PLACE: Via Videoconference

DATE: Wednesday, October 20, 2021

TIME: 9:30 a.m. - 11:11 a.m.

BEFORE: Commissioner ToNola D. Brown-Bland, Presiding

Chair Charlotte A. Mitchell, Presiding

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-5, Sub 632

Application of Public Service Company

Of North Carolina, Inc., for a

General Increase in Rates and Charges

And

G-5, Sub 634

Application for Approval to Modify

Existing Conservation Programs and

Implement New Conservation Programs

VOLUME 1

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

FOR PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.:
Mary Lynne Grigg, Esq.
Kristin M. Athens, Esq.
McGuireWoods LLP
501 Fayetteville Street, Suite 500
Raleigh, North Carolina 27601

FOR EVERGREEN PACKAGING, LLC:
Christina D. Cress, Esq.
Bailey & Dixon, LLP
434 Fayetteville Street, Suite 2500
Raleigh, North Carolina 27601

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

A P P E A R A N C E S Cont'd.:

FOR THE USING AND CONSUMING PUBLIC AND THE CITIZENS OF THE STATE OF NORTH CAROLINA IN THIS MATTER OF PUBLIC INTEREST:

Margaret A. Force, Esq.
Teresa L. Townsend, Esq.
North Carolina Department of Justice
Attorney General's Office
114 West Edenton Street
Raleigh, North Carolina 27603

FOR THE USING AND CONSUMING PUBLIC:

Gina C. Holt, Esq.
John Little, Esq.
Lucy Edmonson, Esq.
Public Staff - North Carolina Utilities Commission
4326 Mail Service Center
Raleigh, North Carolina 27699-4300

TABLE OF CONTENTS

EXAMINATIONS

E X H I B I T S

IDENTIFIED/ADMITTED

P R O C E E D I N G S

COMMISSIONER BROWN-BLAND: Good morning. Let us come to order and go on the record. I am Commissioner ToNola D. Brown-Bland with the North Carolina Utilities Commission, Presiding Commissioner for this hearing. With me this morning, via remote connection, are Chair Charlotte A. Mitchell, Commissioners Lyons Gray, Daniel G. Clodfelter, Kimberly W. Duffley, Jeffrey A. Hughes and Floyd B. McKissick, Jr.

I now call for hearing Docket No. G-5, Sub 632, in the Matter of Application of Public Service Company of North Carolina, Inc., for a General Increase in its Rates and Charges and Docket No. G-5, Sub 634, in the Matter of Application for Approval of Conservation Programs of Public Service Company of North Carolina.

On April 1st, 2021, Public Service Company of North Carolina, Inc. (the Applicant, Company or PSNC) filed an application for a general increase in its rates and charges and filed in support the direct testimony and exhibits of witnesses D. Russell Harris, M. Shaun Randall, Michael B. Phibbs, Jennifer E. Nelson, John D. Taylor, John J. Spanos, James Herndon, Byron W. Hinson and James A. Spaulding.

On April 27th, 2021, the Commission issued an

Order Establishing General Rate Case and Suspending Rates.

The intervention and participation of the Public Staff is recognized pursuant to G.S. 62-15(d) and Commission Rule R1-19(e), and on May 4th, 2021, the Public Staff filed a motion to consolidate Docket No. G-5, Sub 634, regarding Application to Approve Conservation Programs, with Docket No. G-5, Sub 632, the Application for General Rate case -- Rate Increase. The motion to consolidate the dockets was granted by Commission Order dated May 18th, 2021.

Carolina Utility Customers Association, Inc. (CUCA) and Evergreen Packaging, LLC (Evergreen) filed timely petitions to intervene which were granted by respective orders of the Commission issued on April 15th, 2021, and July 14th, 2021. On September 17th, 2021, the Attorney General’s Office filed Notice of Intervention, which is recognized pursuant to North Carolina General Statute 62-20.

On June 11th, 2021, the Commission issued an Order Scheduling Investigations and Hearings, Establishing Intervention and Testimony Due Dates and Discovery Guidelines, and Requiring Public Notice. The Order scheduled a public hearing to be held remotely by

WebEx in two sessions at 1:30 p.m. and 6:30 p.m. on Monday, August 16th, 2021, and scheduled the expert witness evidentiary hearing to begin on Monday, October 18th, 2021, at 2:00 p.m. in Raleigh in the Commission Hearing Room.

On July 15th, 2021, PSNC filed Affidavits of Publication of Public Notice.

On August 10th, 2021, PSNC filed the Supplemental Testimony and Exhibits of witnesses Spaulding, Hinson and Taylor.

On August 12th, 2021, the Company filed a motion to cancel the public hearing, explaining that no witnesses registered with the Public Staff to testify by the deadline noted in the -- in the customer notice. The motion was granted by the Commission on August 13th.

On September 17th, 2021, PSNC filed a Motion to Conduct the Evidentiary Hearing by Remote Means due to public health concerns related to the Coronavirus pandemic. The motion noted that no parties objected to the motion.

On September 23rd, the Public Staff filed the Direct Testimony and Exhibits of Mary A. Coleman, Lynn Feasel, Roxie McCullar, Jack L. Floyd, John R. Hinton, Neha Patel, Julie G. Perry, Sonja R. Johnson, and the

Joint Testimony of James M. Singer and David M. Williamson. On that day, the Public Staff filed the revised testimony and exhibits of witnesses Hinton, Patel and Johnson.

Also on September 23rd, 2021, Evergreen Packaging, LLC, filed the Testimony and Exhibits of Brian C. Collins and CUCA filed the Testimony and Exhibits of Kevin O'Donnell.

On September 24th, 2021, the Commission granted the motion to conduct the hearing by remote means and issued Order Establishing Remote Procedures for Expert Witness Hearing. All parties filed written consent to remote hearing.

On October 5, 2021, the Public Staff filed Revised Johnson Exhibit 1.

On October 7th, 2021, PSNC filed the Rebuttal Testimony and exhibits of witnesses Phibbs, Nelson, Spanos, Taylor, Hinson, Spaulding, and Regina J. Elbert.

On October 13th, 2021, PSNC filed a Motion for Expedited Approval of Notice and Undertaking to Implement Temporary Rates Subject to Refund. The next day, on October 14, the Company filed Revised Public Notice of Temporary Rates and also filed a Motion to Delay Evidentiary Hearing to allow PSNC, the Public Staff, CUCA and Evergreen to finalize and file a stipulation of settlement and supporting testimony and exhibits.

On October 15, 2021, the Commission issued Order Approving Public Notice of Temporary Rates Subject to Refund and Approving Financial Undertaking and issued Order Rescheduling Expert Witness Hearing to this date and time, Wednesday, October 20th, 2021 at 9:30 a.m.

Also on October 15th, 2021, PSNC, the Public Staff, CUCA and Evergreen filed Stipulation of Settlement and also filed a joint motion to excuse specified witnesses. On the same day, PSNC filed the testimony and exhibits of witnesses Hinson, Spaulding and Nelson and the Public Staff filed the testimony and exhibit of witness Johnson in support of Stipulation of Settlement.

On October 18th, 2021, the Public Staff filed the testimony of witness Perry also in support of Stipulation of Settlement.

On October 19th, 2021, the Commission issued an order granting the Stipulating Parties’ joint motion to excuse specified witnesses from attending today’s hearing.

In compliance with the requirements of Chapter 163A of the State Government Ethics Act, I remind the members of the Commission of our responsibility to avoid conflicts of interest, and I inquire whether any member has any known conflict of interest with respect to the matter before us at this time.

(No response.)

COMMISSIONER BROWN-BLAND: The record will reflect that no conflicts were identified.

Before we go further today, I will make just a few points on the record in light of the fact that the 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 at www.ncuc.net.

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 order to verify that they're able to access the remote technology utilized by the Commission 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, but in the event that a party must reference confidential information during testimony, we will leave the video conference and join a teleconference line.

The parties whose confidential information is discussed -- the party whose confidential information is discussed is responsible for ensuring that only those parties who have executed confidentially agreements are on the teleconference line. When -- if we were to leave and go into a confidential session, when the confidential information is -- when discussion of the confidential information is complete, we will leave the line and go back on the public videoconference via WebEx.

Finally, I will ask that all hearing participants keep their microphones muted unless they are actively addressing the Commission in order to avoid interference with the court reporter’s ability to transcribe this proceeding. Additionally, when addressing the Commission, participants should appear on camera.

With that, I’ll now call for appearances of counsel, beginning with the Applicant.

MS. GRIGG: Good morning, Presiding Commissioner Brown-Bland. This is Mary Lynne Grigg with the law firm of McGuireWoods, appearing on behalf of Public Service Company of North Carolina, doing business as Dominion Energy North Carolina.

COMMISSIONER BROWN-BLAND: All right. Thank you, Ms. Grigg. Next?

MS. ATHENS: Good morning. This is Kristin Athens from McGuireWoods, also appearing on behalf of Public Service Company of North Carolina, doing business as Dominion Energy North Carolina. Good morning, everyone.

COMMISSIONER BROWN-BLAND: Good morning. Next party?

MS. FORCE: Good morning. My name is Margaret Force, with the Attorney General's Office. And also appearing with me is Teresa Townsend on behalf of the Using and Consuming Public pursuant to G.S. 62-20 and also on behalf of the state and its citizens pursuant to G.S. 62 -- excuse me, G.S. 114-28.

COMMISSIONER BROWN-BLAND: Ms. Force, you were a little quiet or soft when we were listening to you. I think we heard you. The court reporter is nodding. But when you turned your head, it was a little difficult to hear you.

MS. FORCE: Okay.

COMMISSIONER BROWN-BLAND: So stay focused towards the microphone, and it's good to see you this morning.

MS. FORCE: I was looking at my notes. Thank you.

COMMISSIONER BROWN-BLAND: All right. Next? How about Evergreen?

MS. CRESS: Good morning, Presiding Commissioner Brown-Bland. This is Christina Cress with the Raleigh law firm of Bailey & Dixon, appearing this morning on behalf of Evergreen Packaging, LLC.

COMMISSIONER BROWN-BLAND: Good morning, Ms. Cress. You, too, might also need to speak up a little bit. I think we got you, but we had -- we had identified that issue earlier. So I'm -- I'm aware.

CUCA?

MR. SCHAUER: Good morning. Craig Schauer with the firm of Brooks Pierce, appearing -- appearing on behalf of the Carolina Utilities Customers Association.

COMMISSIONER BROWN-BLAND: Good morning, Mr. Schauer.

MR. SCHAUER: Good morning, Commissioner.

COMMISSIONER BROWN-BLAND: And the Public Staff?

MS. HOLT: Good morning. I'm Gina Holt with the Public Staff, here on behalf of the Using and Consuming Public. And appearing with me today are Public Staff attorneys John Little and Lucy Edmondson.

COMMISSIONER BROWN-BLAND: Good morning, Public Staff Team. Good to see you.

All right. Are there any preliminary matters that need to come to the Commission's attention before we start?

(No response.)

COMMISSIONER BROWN-BLAND: Looks like there are none. And so the case is with the applicant.

MS. GRIGG: Good morning again, Presiding Commissioner Brown-Bland. PSNC would like to call our first witness to the stand, Ms. Jennifer E. Nelson.

(WHEREUPON,

JENNIFER E. NELSON,

having been duly affirmed, testified as follows:)

MS. GRIGG: Thank you, Commissioner. My screen is not showing Ms. Nelson, but I assume y'all are seeing her.

COMMISSIONER BROWN-BLAND: No. Actually, mine is not either.

MS. GRIGG: I wonder if other people turn off their video if she'll appear. Would that --

COMMISSIONER BROWN-BLAND: That should not be the issue. Make sure that she has her camera on? Has she checked her video button?

THE WITNESS: My video is on and I see myself at the top of the screen.

COMMISSIONER BROWN-BLAND: There you are. We see you now.

THE WITNESS: There I am. Okay.

COMMISSIONER BROWN-BLAND: I guess WebEx was just a little bit sleepy this morning. Thank you.

MS. GRIGG: I think it’s helpful to see her. Thank you.

DIRECT EXAMINATION BY MS. GRIGG:

Q. Good morning, Ms. Nelson.

A. Good morning.

Q. Would you please state your name and business address for the record?

A. My name is Jennifer E. Nelson. And I'm an Assistant Vice President at Concentric Energy Advisors, and my business address is 293 Boston Post Road West, Suite 500, in Marlborough -- that's spelled M-a-r-l-b-o-r-o-u-g-h -- Massachusetts 01742.

Q. Thank you. Did you cause to be prefiled in these dockets on April 1st, 2021, 79 pages of direct testimony and eight (8) exhibits?

A. Yes, I did.

Q. Do you have any changes or corrections to your direct testimony or exhibits?

A. No, I do not.

Q. If I were to ask you the same questions today that appear in your direct testimony, would your answers be the same?

A. Yes, they would.

Q. Ms. Nelson, did you also cause to be prefiled in these dockets on October 7th, 2021, 76 pages of rebuttal testimony and 16 exhibits?

A. Yes, I did.

Q. Do you have any changes or corrections to your rebuttal testimony or exhibits?

A. Yes, I have two changes. The first change is on -- both are on Page 11 of my rebuttal testimony. Starting at Line 8, I would like to strike the words "in the top third, i.e., average/1" and replace that with "above average/3."

On Line 9, I would like to replace the words "average/2" with "average/1." And those are all my changes.

Q. Thank you. Other than the changes you note, if I were to ask you the same questions that appear in your rebuttal testimony today, would your answers be the same?

A. Yes, they would.

Q. Ms. Nelson, did you also cause to be prefiled in these dockets on October 15th, 2021, ten (10) pages of settlement testimony and two (2) exhibits?

A. Yes, I did.

Q. Do you have any changes or corrections to your settlement testimony or exhibits?

A. No, I do not.

Q. If I were to ask you the same questions that appear in your settlement testimony today, would your answers be the same?

A. Yes, they would.

Q. Ms. Nelson, did you prepare a summary of your testimonies?

A. Yes, I did.

Q. Will you please read it for the Commission at this time?

A. Since the filing of my direct and rebuttal testimony, PSNC has reached a Stipulation of Settlement with the Public Staff, Carolina Utility Customers Association, Inc., and Evergreen Packaging, LLC. The testimony I have filed in support of the Stipulation on October 15th, 2021, addresses and provides support for the return on equity, capital structure and overall rate of return agreed upon by the stipulating parties.

Specifically, the stipulating parties have agreed to a return on equity of 9.60 percent, a capital structure consisting of 51.60 percent common equity, 47.06 percent long-term debt and 1.34 percent short-term debt, and an overall rate of return of 7.07 percent. Although the agreed upon return on equity is at the low end of my initial ROE recommendations described in my direct and rebuttal testimonies, I believe the components of the Stipulation contribute to a reasonable resolution of all issues in this proceeding and should be approved. That's the conclusion of my summary.

Q. Thank you.

MS. GRIGG: Presiding Chair Brown-Bland, at this time, I move that the prefiled direct, rebuttal and settlement testimonies of Ms. Nelson be copied into the record as if given orally from the stand and that her eight (8) direct exhibits, 16 rebuttal exhibits and two (2) settlement exhibits be identified as prefiled.

COMMISSIONER BROWN-BLAND: Ms. Grigg, that motion will be allowed and the direct, rebuttal and settlement prefiled testimony of witness Nelson will be received into the record as if given -- be received into evidence as if given orally from the witness stand. And the corresponding prefiled exhibits will be identified as they were marked when prefiled.

(Nelson Direct Exhibits 1 through 8, Nelson Rebuttal Exhibits 1 through 16, and Nelson Settlement Exhibits 1 and 2 were marked for identification and received into evidence.)

(Whereupon, the prefiled direct, rebuttal and settlement testimonies of Jennifer E. Nelson were copied into the record as if given from the stand.)

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET G-5, SUB 632

DIRECT TESTIMONY

OF

JENNIFER E. NELSON

APRIL 1, 2021

TABLE OF CONTENTS

Page

I. WITNESS IDENTIFICATION AND QUALIFICATIONS

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

A. My name is Jennifer E. Nelson. I am an Assistant Vice President at Concentric Energy Advisors. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01742.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this direct testimony ("Direct Testimony") before the North Carolina Utilities Commission ("Commission") on behalf of Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or the "Company").

Q. PLEASE DESCRIBE YOUR EDUCATIONAL BACKGROUND.

A. I hold a Bachelor's degree in Business Economics from Bentley College (now Bentley University) and a Master's degree in Resource and Applied Economics from the University of Alaska.

Q. PLEASE DESCRIBE YOUR EXPERIENCE IN THE ENERGY AND UTILITY INDUSTRIES.

A. I have worked in the energy industry for nearly thirteen years, having served as a consultant and energy/regulatory economist for state government agencies. Since 2013, I have provided consulting services to utility and regulated energy clients on a range of financial and economic issues including rate case support (*e.g.*, Cost of Capital and integrated resource planning) and policy and strategy issues (*e.g.*, alternative ratemaking and natural gas distribution expansion).

Prior to consulting, I was a staff economist at the Massachusetts Department of Public Utilities, where I worked on regulatory filings related to energy efficiency, renewable power contracts, smart grid and electric grid modernization, and retail choice; prior to that I was a petroleum economist at the State of Alaska Department of Revenue. A summary of my professional and educational background, including a list of my testimony filed before regulatory commissions, is included as Nelson Direct Exhibit 1.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THE COMMISSION?

A. No, I have not. However, I have previously filed testimony before regulatory commissions in Arkansas, Kentucky, Maine, New Mexico, Texas, and West Virginia. During my time as a consultant, I have supported the development of expert witness testimony and analyses regarding the Cost of Capital (*i.e.*, Return on Equity, "ROE", and capital structure) in more than 100 proceedings filed before numerous U.S. state regulatory commissions and the Federal Energy Regulatory Commission.

II. PURPOSE AND OVERVIEW OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR DIRECT TESTIMONY?

A. The purpose of my Direct Testimony is to present evidence and provide the Commission with a recommendation regarding the Company's ROE[1] and to assess the reasonableness of the Company's requested capital structure. My analyses and conclusions are supported by the data presented in Nelson Direct

[1] Throughout my testimony, I interchangeably use the terms "ROE" and "Cost of Equity."

Exhibit 2 through Nelson Direct Exhibit 8, which have been prepared by me or under my direction.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE APPROPRIATE COST OF EQUITY AND CAPITAL STRUCTURE FOR THE COMPANY?

A. My analyses indicate that an ROE in the range of 9.60 percent to 10.75 percent represents the range of equity investors' required return for investment in a natural gas utility such as PSNC in today's volatile capital market environment. To develop my recommended range, I considered the quantitative and qualitative analyses discussed throughout my Direct Testimony, the current capital market environment, the Company's relatively small size, and the Commission's ROE decisions in recent proceedings. Additionally, I considered the current economic conditions in North Carolina. Based on those factors, I conclude that 10.25 percent is a reasonable and appropriate estimate of PSNC's Cost of Equity.

As to the capital structure, I conclude the Company's requested capital structure consisting of 54.88 percent common equity, 1.33 percent short-term debt, and 43.79 percent long-term debt is consistent with the proxy group and, is, therefore, reasonable and should be approved.

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF THE ANALYSES THAT LED TO YOUR ROE DETERMINATION.

A. The Cost of Equity, which is the return required by equity investors to assume the risks of ownership, is a market-based concept. Because it is unobservable, the Cost of Equity is estimated based on market data applied to financial models. Since all financial models are subject to various assumptions and constraints, equity analysts and investors tend to use multiple methods to develop their return requirements. As such, I relied on three widely accepted approaches to develop my ROE range and estimate: (1) the constant growth and quarterly forms of the Discounted Cash Flow ("DCF") model; (2) the traditional and empirical forms of the Capital Asset Pricing Model ("CAPM"); and (3) the Bond Yield Plus Risk Premium approach. The results of those analytical approaches are summarized in Table 1 below.

Table 1: Summary of Results[2]

Constant Growth DCF	**Low**	**Mean**	**High**
30-Day Average	9.47%	10.13%	10.98%
90-Day Average	9.51%	10.25%	10.92%
180-Day Average	9.56%	10.23%	10.89%
Quarterly Growth DCF	**Low**	**Mean**	**High**
30-Day Average	9.63%	10.32%	11.14%
90-Day Average	9.67%	10.41%	11.08%
180-Day Average	9.73%	10.37%	11.12%
***Value Line*-based CAPM**		**Current 30-Year Treasury Yield (1.97%)**	**Projected 30-Year Treasury Yield (2.72%)**
Proxy Group Average		12.92%	13.01%
Proxy Group Median		12.48%	12.59%
***Value Line*-based Empirical CAPM**		**Current 30-Year Treasury Yield (1.97%)**	**Projected 30-Year Treasury Yield (2.72%)**
Proxy Group Average		13.28%	13.34%
Proxy Group Median		12.95%	13.03%
Bond Yield Plus Risk Premium			
Current 30-Year Treasury Yield (1.97%)		9.86%	
Projected 30-Year Treasury Yield (2.72%)		9.75%	

In addition to the methods noted above, I considered the Company's small size relative to the proxy group in my recommendation. I also considered the currently unstable capital market and the economic conditions in North Carolina. Although those factors are relevant to investors, their effect on the Company's Cost of Equity cannot be directly quantified. Therefore, rather than make explicit adjustments to my ROE estimates in connection with those

[2] *See,* Nelson Direct Exhibits 2, 3, 5, 6. DCF model results are the average of the mean and median proxy group results.

factors, I considered them in determining where the Company's Cost of Equity falls within the range of analytical results

Q. HOW DID YOU DETERMINE YOUR RECOMMENDED RANGE FROM THE METHODS AND RESULTS SUMMARIZED ABOVE?

A. As noted earlier, because the Cost of Equity is not directly observable, it must be estimated based on both quantitative and qualitative information. As my Direct Testimony explains, no single model is more reliable than all others under all market conditions. All models used to estimate the Cost of Equity are subject to certain assumptions, which may become more or less relevant as market conditions change. Each model's results must be assessed in the context of current and expected capital market conditions, as well as relative to appropriate benchmarks. Consequently, many finance texts recommend using multiple approaches to estimate the Cost of Equity.[3] Because estimating the Cost of Equity is an approximation of investor behavior and cannot be precisely quantified, analysts and investors are inclined to gather and evaluate relevant data from a wide variety of sources available to them and, therefore, rely on multiple analytical approaches. The use of various financial models provides different perspectives on investor return requirements, which enables a more robust and comprehensive assessment of the Cost of Equity.

[3] *See, for example,* Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341, and Tom Copeland, Tim Koller and Jack Murrin, Valuation: Measuring and Managing the Value of Companies, 3rd Ed., 2000, at 214.

Simply, each model has strengths and weaknesses, and it is important to recognize those differences when estimating the Cost of Equity. For example, the Constant Growth DCF model requires constant assumptions, inputs, and results in perpetuity, while Risk Premium-based methods provide the ability to reflect investors' views of risk, future market returns, and the relationship between interest rates and the Cost of Equity.

My recommendation therefore recognizes that estimating the Cost of Equity is not an entirely mathematical exercise. It relies on both quantitative and qualitative data and analyses, all of which are used to inform the judgment that necessarily must be applied in determining the Cost of Equity for a particular company at a particular time. As such, I considered my analytical results in the context of Company-specific factors and current capital market conditions. In developing my recommendation, I considered the quantitative results produced by each model and their comparability to returns available to other similarly-situated natural gas utilities, as well as each model's consistency with, and reflection of, the current capital market environment. Moreover, selecting a range at the lower end[4] of the range of analytical results considers the weakened, but improving economic conditions in North Carolina described in Section V below. Although my analytical results and current conditions suggest the investor-required ROE now falls toward the higher end of my range,

[4] My recommended range of 9.60 percent to 10.75 percent ranks in the 9th to 51st percent (*i.e.*, lower half) of the analytical results presented in Table 1 above.

I conclude an ROE of 10.25 percent is reasonable and conservative in light of current market uncertainty, the economic conditions in North Carolina.

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 issues regarding Cost of Equity estimation in regulatory proceedings and discusses the regulatory guidelines pertinent to the development of the Cost of Capital, explains my selection of the proxy group used to develop my analytical results, and describes the analyses on which my ROE determination is based;
- Section IV – Discusses the Company's relatively small size and the direct bearing on its Cost of Equity;
- Section V – Discusses the current North Carolina economic conditions;
- Section VI – Highlights the current capital market conditions and their effect on PSNC's Cost of Equity;
- Section VII – Provides an assessment of the Company's requested capital structure; and
- Section VIII – Summarizes my conclusions.

III. COST OF EQUITY ESTIMATION

A. Regulatory Guidelines and Financial Considerations

Q. BEFORE ADDRESSING THE SPECIFIC ASPECTS OF THIS PROCEEDING, PLEASE PROVIDE A GENERAL OVERVIEW OF THE ISSUES SURROUNDING THE COST OF EQUITY IN REGULATORY PROCEEDINGS.

A. As noted previously, the Cost of Equity is the return that investors require to make an equity 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. From the firm's perspective, that required return, whether it is provided to debt or equity investors, has a cost. Individually, we speak of the "Cost of Debt" and the "Cost of Equity" as measures of those costs; together, they are referred to as the "Cost of Capital."

The Cost of Capital (*i.e.*, the costs of both 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. In that important respect, the returns required by debt and equity investors represent a cost to the Company.

Although both debt and equity have required costs, they differ in certain fundamental ways. Most noticeably, the Cost of Debt is contractually defined and can be directly observed as the interest rate or yield on debt securities.[5] The Cost of Equity, on the other hand, is neither directly observable nor a contractual obligation. Rather, equity investors have a claim on cash flows only after debt holders are paid; the uncertainty (or risk) associated with those residual cash flows determines the Cost of Equity. Because equity investors bear the "residual risk," they take greater risks and require higher returns than debt holders. In that basic sense, equity and debt investors differ – they invest in different securities, face different risks, and require different returns.

Whereas the Cost of Debt can be directly observed, the Cost of Equity must be estimated based on market data and various financial models. As discussed throughout my Direct Testimony, each of those models is subject to certain assumptions, which may be more or less applicable under differing market conditions. Further, because the Cost of Equity is premised on opportunity costs, the models are typically applied to a group of "comparable" or "proxy" companies. The choice of models (including their inputs), the selection of proxy companies, and the interpretation of the model results all require the application of reasoned judgment. That judgment should consider data and information that is not necessarily included in the models themselves.

[5] The observed interest rate may be adjusted to reflect issuance or other directly observable costs.

In the end, the estimated Cost of Equity should reflect the return that investors require considering the subject company's risks, and the returns available on comparable investments. A given utility stock may require a higher return based on the risks to which it is exposed, or its expected growth, relative to other utilities. That is, although utilities may be viewed as a "sector," not all require the same return.

Q. PLEASE BRIEFLY SUMMARIZE THE GUIDELINES ESTABLISHED BY THE UNITED STATES SUPREME COURT (THE "SUPREME COURT") FOR THE PURPOSE OF DETERMINING THE RETURN ON EQUITY.

A. The Supreme Court established the guiding principles for establishing a fair return for capital in two cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. ("*Bluefield*");[6] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*").[7] In *Bluefield*, the Court stated:

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[8]

---

[6] *See, Bluefield Water Works and Improvement Co. v. Public Service Comm'n*. 262 U.S. 679, 692 (1923).

[7] *See, Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944).

[8] *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* 262 U.S. 679, 692 (1923).

The Supreme Court therefore recognized that: (1) a regulated public utility cannot remain financially sound unless the return it is allowed to earn on its invested capital is at least equal to the Cost of Capital (the principle relating to the demand for capital); and (2) a regulated public utility will not be able to attract capital if it does not offer investors an opportunity to earn a return on their investment equal to the return they expect to earn on other investments of similar risk (the principle relating to the supply of capital).

In *Hope*, the Supreme Court reiterates the financial integrity and capital attraction principles of the *Bluefield* case:

> 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... 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.[9]

In summary, the Supreme Court has recognized that the fair rate of return on equity should be: (1) comparable to returns investors expect to earn on other investments of similar risk; (2) sufficient to assure confidence in the company's financial integrity; and (3) adequate to maintain and support the company's credit and to attract capital.

---

[9] *Federal Power Comm'n v. Hope Natural Gas Co.,* 320 U.S. 591, 603 (1944).

Q. HAS THE COMMISSION ALSO LOOKED TO THE *HOPE* AND *BLUEFIELD* STANDARDS AS GUIDANCE FOR SETTING RATES?

A. Yes, it has. For example, in Docket No. E-7, Sub. 1026, the Commission noted that:

> First, there are, as the Commission noted in the DEP Rate Order, constitutional constraints upon the Commission's return on equity decision, established by the United States Supreme Court decisions in Bluefield Waterworks & Improvement Co., v. Pub. Serv. Comm'n of W. Va., 262 U.S. 679 (1923) (Bluefield), and Fed. Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1944) (Hope):
>
> To fix rates that do not allow a utility to recover its costs, including the cost of equity capital, would be an unconstitutional taking. In assessing the impact of changing economic conditions on customers in setting an ROE, the Commission must still provide the public utility with the opportunity, by sound management, to (1) produce a fair profit for its shareholders, in view of current economic conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. State ex rel. Utilities Commission v. General Telephone Co. of the Southeast, 281 N.C. 318, 370, 189 S. E.2d 705, 757 (1972). As the Supreme Court held in that case, these factors constitute "the test of a fair rate of return declared" in Bluefield and Hope. Id.[10]

Based on those standards, the authorized ROE should provide the Company with the opportunity (which is not a guarantee) to earn a fair and reasonable return and enable efficient access to external capital under a variety of market conditions.

---

[10] North Carolina Utilities Commission, Docket No. E-7, Sub 1026, *Order Granting General Rate Increase*, September 24, 2013, at 23.

Q. WHY IS IT IMPORTANT FOR A UTILITY TO BE ALLOWED THE OPPORTUNITY TO EARN A RETURN ADEQUATE TO ATTRACT CAPITAL AT REASONABLE TERMS?

A. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe and reliable service while maintaining its financial integrity. As discussed above, and in keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected for investments of equivalent risk.

The ratemaking process is based on the principle that, for investors and companies to commit the capital needed to provide safe and reliable utility services, the utility must have the opportunity to recover the return of, and the market-required return on, invested capital. The allowed ROE should enable the subject utility to maintain its financial integrity in a variety of economic and capital market conditions. In order to preserve and enhance service reliability, PSNC must generate adequate cash flow from operations and have efficient access to external capital needed to undertake its capital investment plan regardless of the economic and capital market conditions at the time. A return that is adequate to attract capital at reasonable terms enables the utility to provide safe, reliable service while maintaining its financial soundness.

Further, the financial community carefully monitors utility companies' current and expected financial conditions, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk.[11] That consideration is especially important during uncertain economic and financial conditions in which the utility may require access to capital markets.

The outcome of the Commission's order in this case, therefore, should provide PSNC with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments in enterprises having corresponding risks. To the extent PSNC is provided a reasonable opportunity to earn its market-based Cost of Equity, neither customers nor shareholders are disadvantaged. In fact, a return that is adequate to attract capital at reasonable terms enables PSNC to provide safe, reliable natural gas utility service while maintaining its financial integrity.

Q. DOES THE REGULATORY ENVIRONMENT INFLUENCE UTILITIES' EFFICIENT ACCESS TO CAPITAL?

A. Yes, it does. The regulatory environment is a key driver of investors' risk assessment for utilities. Investors and rating agencies understand that a constructive regulatory environment is critical to support utilities' credit ratings and financial integrity, especially during adverse market conditions.

Moody's Investors Service ("Moody's) considers the regulatory structure to be so important that 50.00 percent of the factors that weigh in a

[11] *See, e.g.*, Moody's Investor Service, Rating Methodology, *Regulated Electric and Gas Utilities*, June 23, 2017, at 4.

ratings determination are related to the nature of regulation.[12] Among the factors considered by Moody's in assessing the regulatory framework are the predictability and consistency of regulatory actions:

> As the revenues set by the regulator are a primary component of a utility's cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality. The regulatory framework generally provides more certainty around a utility's cash flow and typically allows the company to operate with significantly less cushion in its cash flow metrics than comparably rated companies in other industrial sectors.
>
> ***
>
> In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly.[13]

Similarly, as Standard & Poor's ("S&P") notes, "Regulatory advantage is the most heavily weighted factor when S&P Global Ratings analyzes a regulated utility's business risk profile."[14]

Q. HOW IS THE COST OF EQUITY 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

---

[12] *See,* Moody's Investors Service, Rating Methodology, *Regulated Gas and Electric Utilities*, at 4 (June 23, 2017).

[13] Moody's Investors Service, *Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities*, at 2 (June 18, 2010).

[14] S&P Global Ratings, *Assessing U.S. Investor-Owned Utility Regulatory Environments*, at 2 (August 10, 2016).

which the costs of the individual sources of capital are weighted by their respective book values.

As noted earlier, the ROE is market-based and, therefore, is estimated by applying observable market data to various financial models. By their nature, those models produce a range of results from which the ROE is determined. Although quantitative models are used to estimate the ROE, it cannot be precisely quantified through a strict mathematical solution. Other regulatory commissions have found no individual model is more reliable than all others under all market conditions.[15] Consistent with investor practice, it is both prudent and appropriate to use multiple methods to mitigate the effects of assumptions and inputs associated with any single approach. The key consideration in determining the ROE is to ensure the overall analysis reasonably reflects investors' view of financial markets in general, and the subject company (in the context of the proxy companies), in particular.

In summary, practitioners, academics, and regulatory commissions recognize that financial models are not precise quantifications of investor behavior but are tools to be used in the ROE estimation process. They appreciate that the strict adherence to any single approach, or to the specific

[15] *See, for example*: (1) Public Utilities Commission of the State of Hawaii, Docket No. 7700, Order No. 13704 in Docket No. 7700, *In the Matter of the Application of Hawaiian Electric Company, Inc. For Approval of Rate Increases and Revised Rate Schedules and Rules*, December 28, 1994 at 92; (2) The Commonwealth of Massachusetts Department of Public Utilities, *Investigation by the Department of Public Utilities*, Docket D.P.U. 15-155, September 30, 2016, at 376-378; and (3) State of North Carolina Utilities Commission, *In the Matter of Application of Public Service Company of North Carolina, Inc. for a General Increase in its Rates and Charges*, Docket No. G-5, Sub 565, Order Approving Rate Increase and Integrity Management Tracker, October 28, 2016, at 35-36.

results of any single approach, can lead to flawed or misleading conclusions.[16] A reasonable ROE estimate therefore considers multiple methods and the reasonableness of their individual and collective results in the context of observable, relevant market information.

B. Proxy Group Selection

Q. AS A PRELIMINARY MATTER, WHY IS IT NECESSARY TO SELECT A GROUP OF PROXY COMPANIES TO DETERMINE THE COST OF EQUITY FOR PSNC?

A. First, it is important to bear in mind that the Cost of Equity for a given enterprise depends on the risks attendant to the business in which the company is engaged. According to financial theory, the value of a given company is equal to the aggregate market value of its constituent business units. The value of the individual business units reflects the risks and opportunities inherent in the business sectors in which those units operate. In this proceeding, we are focused on estimating the Cost of Equity for PSNC, whose ultimate parent is Dominion Energy, Inc ("DEI"). Because the ROE is a market-based concept, and PSNC is not a separate entity with its own stock price, it is necessary to establish a group of companies that are both publicly traded and generally comparable to the Company in certain fundamental respects to serve as its "proxy" in the ROE estimation process. Even if the Company were a publicly traded entity, short-term events could bias its market value during a given time

[16] This is consistent with the *Hope* and *Bluefield* principle establishing it is the analytical result, as opposed to the method employed, that controls in determining just and reasonable rates.

period. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company.

Q. DOES THE SELECTION OF A PROXY GROUP SUGGEST THAT ANALYTICAL RESULTS WILL BE TIGHTLY CLUSTERED AROUND AVERAGE (*I.E.*, MEAN) RESULTS?

A. Not necessarily. For example, the Constant Growth DCF approach defines the Cost of Equity as the sum of the expected dividend yield and projected long-term growth. Despite the care taken to ensure risk comparability, market expectations with respect to future risks and growth opportunities will vary from company to company. Therefore, even within a group of similarly situated companies, it is common for analytical results to reflect a seemingly wide range. Consequently, at issue is how to estimate the Cost of Equity from within that range. Such a determination necessarily must consider both quantitative and qualitative information.

Q. PLEASE PROVIDE A SUMMARY PROFILE OF PSNC.

A. PSNC is a wholly owned subsidiary of SCANA Corporation, which is a wholly owned subsidiary of DEI. DEI provides gas distribution services to approximately 3.10 million customers in Idaho, North Carolina, Ohio, South Carolina, Utah, West Virginia, and Wyoming.[17] PSNC serves approximately

[17] Dominion Energy, Inc., SEC Form 10-K for the fiscal year ended December 31, 2020, at 17.

600,000 customers in North Carolina.[18] PSNC's current long-term issuer credit ratings are as follows:

Table 2: PSNC Current Credit Ratings[19]

S&P	Moody's
BBB+ (Outlook: Positive)	Baa1 (Outlook: Stable)

Q. HOW DID YOU SELECT THE COMPANIES INCLUDED IN YOUR PROXY GROUP?

A. A proxy group should consist of companies with risk profiles comparable to the subject company. In selecting a proxy group, my objective was to balance the competing interests of selecting companies that are representative of the risks and prospects faced by PSNC, while at the same time ensuring that there is a sufficient number of companies in the proxy group. Based on those two considerations, I began with the universe of companies that *Value Line* classifies as Natural Gas Utilities and applied the following screening criteria:

- Because certain of the models used in my analyses assume that earnings and dividends grow over time, I excluded companies that do not consistently pay quarterly cash dividends, or have cut their dividend in the last five years;
- To ensure that the growth rates used in my analyses are not biased by a single analyst, all the companies in my proxy group are consistently covered by at least two utility industry equity analysts;
- All the companies in my proxy group have investment grade senior unsecured bond and/or corporate credit ratings from S&P and/or Moody's Investor's Service;

[18] Source: S&P Global Market Intelligence.

[19] Source: S&P Global Market Intelligence.

- To incorporate companies that are primarily regulated gas distribution utilities, I included companies with at least 60.00 percent of net operating income from regulated natural gas utility operations, on average, over the last three years; and
- I eliminated companies that have recent merger activity, other significant transactions, or have had any recent financial event that could affect its market data or financial condition.

Q. DID YOU INCLUDE DEI IN YOUR ANALYSES?

A. No. DEI is not classified by *Value Line* as a natural gas utility, nor does it meet my screening criterion of having at least 60.00 percent of net operating income from regulated natural gas utility operations. Further, it would be circular logic to include PSNC's ultimate parent company in my analyses.

Q. WHICH COMPANIES MET YOUR SCREENING CRITERIA?

A. The criteria discussed above resulted in a proxy group of the following seven companies:

Table 3: Proxy Group Screening Results

Company	Ticker
Atmos Energy Corporation	ATO
New Jersey Resources Corporation	NJR
Northwest Natural Holding Company	NWN
ONE Gas, Inc.	OGS
South Jersey Industries	SJI
Southwest Gas Holdings, Inc.	SWX
Spire Inc.	SR

Q. IS A PROXY GROUP OF SEVEN COMPANIES SUFFICIENTLY LARGE?

A. Yes. The analyses performed in estimating the ROE are more likely to be representative of the subject utility's Cost of Equity to the extent that the chosen proxy companies are fundamentally comparable to the subject utility. Because all analysts use some form of screening process to arrive at a proxy group, the group, by definition, is not randomly drawn from a larger population. Consequently, there is no reason to place more reliance on the quantitative results of a larger proxy group simply by virtue of having more observations.

Moreover, because I am using market-based data, my analytical results will not necessarily be tightly clustered around a central point. Results that may be somewhat dispersed, on the other hand, do not suggest that the screening approach is inappropriate or the results less meaningful. In my view, including companies whose fundamental comparability may be tenuous at best, simply for the purpose of expanding the number of observations, does not add relevant information to the analysis.

C. Cost of Equity Models

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

A. As discussed earlier, I have relied on the constant growth and quarterly forms of the DCF model, the traditional and empirical forms of the CAPM, and the Bond Yield Plus Risk Premium approach.

I rely on these models for two reasons. First, the purpose of an ROE analysis is to estimate the return that investors require; therefore, it is important to use models on which those investors rely. The models I apply are commonly used in practice.[20] Second, the models focus on different aspects of return requirements, and provide different insights to investors' views of risk and return. As explained earlier, using multiple methods provides a broader, and therefore, more reliable perspective on investors' return requirements.

1. Constant Growth Discounted Cash Flow Model

Q. PLEASE DESCRIBE THE CONSTANT GROWTH DCF APPROACH.

A. The Constant Growth DCF approach is based on the theory that a stock's current price represents the present value of all expected future cash flows. DCF theory assumes that an investor buys a stock for an expected total return rate, which is derived from cash flows received in the form of dividends plus appreciation in market price (the expected growth rate). In its simplest form, the Constant Growth DCF model expresses the Cost of Equity as the discount rate that sets the current price equal to expected cash flows:

$$P = \frac{D_1}{(1+k)} + \frac{D_2}{(1+k)^2} + \cdots + \frac{D_\infty}{(1+k)^\infty} \qquad [1]$$

where P represents the current stock price, $D_1 \ldots D_\infty$ represent expected future dividends, and k is the discount rate, or required ROE. Equation [1] is a standard present value calculation that can be simplified and rearranged into the familiar form:

$$k = \frac{\mathrm{D_0}\ (1+g)}{\mathrm{P}} + g \qquad [2]$$

[20] *See, for example,* Eugene Brigham, Louis Gapenski, Financial Management: Theory and Practice, 7th Ed., 1994, at 341.

Equation [2] often is referred to as the "Constant Growth DCF" model, in which the first term is the expected dividend yield, and the second term is the expected long-term annual growth rate in perpetuity.

Q. WHAT ASSUMPTIONS UNDERLIE THE CONSTANT GROWTH DCF MODEL?

A. The Constant Growth DCF model assumes: (1) a constant average annual growth rate for earnings and dividends; (2) a stable dividend payout ratio; (3) a constant Price/Earnings multiple; and (4) a discount rate greater than the expected growth rate. The model also assumes that the current Cost of Equity will remain constant in perpetuity.

Q. WHAT MARKET DATA DID YOU USE TO CALCULATE THE DIVIDEND YIELD IN YOUR CONSTANT GROWTH DCF MODEL?

A. The dividend yield is based on the proxy companies' current quarterly dividend multiplied by four, and the average closing stock prices over the 30-, 90-, and 180-trading day periods as of February 26, 2021.

Q. WHY DID YOU USE THREE AVERAGING PERIODS TO CALCULATE AN AVERAGE STOCK PRICE?

A. I did so to ensure that the model's results are not skewed by anomalous events that may affect stock prices on any given trading day. At the same time, the averaging period should be reasonably representative of expected capital market conditions over the long term. Using 30-, 90-, and 180-trading day averaging periods reasonably balances those concerns.

Q. DID YOU MAKE ANY ADJUSTMENTS TO THE DIVIDEND YIELD TO ACCOUNT FOR PERIODIC GROWTH IN DIVIDENDS?

A. Yes, I did. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. That adjustment ensures that the expected dividend yield is, on average, representative of the coming 12-month period, and does not overstate the dividends to be paid during that time.

Q. WHAT MEASURES OF LONG-TERM GROWTH DID YOU APPLY IN THE DCF MODEL?

A. I have applied analysts' consensus projected earnings per share ("EPS") growth rates. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [2] above) assumes a single expected growth estimate in perpetuity. Accordingly, in order to reduce the long-term growth rate to a single measure, one must assume a fixed payout ratio, and the same constant growth rate in EPS, dividends per share, and book value per share. Since dividend growth can only be sustained by earnings growth, the model should incorporate a variety of measures of long-term earnings growth. This can be accomplished by averaging those measures of long-term growth that tend to be least influenced by capital allocation decisions that companies may make in response to near-term changes in the business environment. Because such decisions may directly affect near-term dividend payout ratios, estimates of earnings growth are more indicative of long-term investor expectations than are dividend growth estimates. For the purposes of the Constant Growth DCF model, therefore, growth in EPS represents the appropriate measure of long-term growth.

Q. PLEASE SUMMARIZE THE FINDINGS OF ACADEMIC RESEARCH ON THE APPROPRIATE MEASURE FOR ESTIMATING EQUITY RETURNS USING THE CONSTANT GROWTH DCF MODEL.

A. The relationship between various growth rates and stock valuation metrics has been the subject of much academic research.[21] As noted by Charles Phillips over 40 years ago in The Economics of Regulation:

> For many years, it was thought that investors bought utility stocks largely on the basis of dividends. More recently, however, studies indicate that the market is valuing utility stocks with reference to total per share earnings, so that the earnings-price ratio has assumed increased emphasis in rate cases.[22]

Subsequent academic research has clearly and consistently indicated that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[23] For example, Vander Weide and Carleton state that,

---

[21] *See,* Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

[22] Charles F. Phillips, Jr., The Economics of Regulation, at 285 (Rev. ed. 1969).

[23] *See, e.g.*, Andreas C. Christofi, Petros C. Christofi, Marcus Lori and Donald M. Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, 21 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

"[our] results … are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions."[24] Other research specifically notes the importance of analysts' growth estimates in determining the Cost of Equity, and in the valuation of equity securities. Dr. Robert Harris noted that "a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices." Citing Cragg and Malkiel, Dr. Harris notes that those authors "found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based."[25] Similarly, Brigham, Shome, and Vinson noted that "evidence in the current literature indicates that (i) analysts' forecasts are superior to forecasts based solely on time series data; and (ii) investors do rely on analysts' forecasts."[26]

To that point, the research of Vander Weide and Carleton demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[27] Those findings suggest that investors form their investment decisions based on expectations of growth in earnings, not dividends. Consequently, earnings growth, not

---

[24] James H. Vander Weide and Willard T. Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

[25] Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

[26] 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).

[27] *See,* Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988).

dividend growth, is the appropriate estimate for the purpose of the Constant Growth DCF model.

Q. PLEASE SUMMARIZE YOUR INPUTS TO THE CONSTANT GROWTH DCF MODEL.

A. I applied the Constant Growth DCF model to the proxy group of natural gas distribution utility companies using the following inputs for the price and dividend terms:

- The average daily closing prices for the 30-, 90-, and 180-trading days ended February 26, 2021, for the term P_0; and
- The annualized dividend per share as of February 26, 2021, for the term D_0.

I then calculated my Constant Growth DCF results using each of the following growth terms:

- Zacks consensus long-term earnings growth estimates;
- First Call consensus long-term earnings growth estimates; and
- *Value Line* long-term earnings growth estimates.

Q. DID YOU REVIEW THE EARNINGS GROWTH RATES INCLUDED IN YOUR ANALYSIS FOR OUTLIERS?

A. Yes, I did. I excluded from my calculations earnings growth rates that were more than one standard deviation above or below the average earnings growth rate projection for the proxy group (7.70 percent).[28] Based on that criterion,

[28] One standard deviation is 5.45 percent; the low outlier threshold is 2.25 percent (7.70 percent – 5.45 percent) and the high outlier threshold is 13.15 percent (7.70 percent + 5.45 percent).

three growth rates were removed: (1) the 1.50 percent earnings growth rate for New Jersey Resources from *Value Line*, (2) the 24.50 percent earnings growth rate for South Jersey Industries from Zacks, and (3) the 24.50 percent earnings growth rate for South Jersey Industries from Yahoo! First Call.

Q. HOW DID YOU CALCULATE THE DCF RESULTS?

A. For each proxy company, I calculated the low, mean, and high DCF (excluding the outlier growth rates discussed above). For the mean result, I combined the average of the three EPS growth rate estimates listed above with the subject company's expected dividend yield for each proxy company. I calculated the high DCF result by combining the maximum EPS growth rate estimate with the subject company's expected dividend yield. I used the same approach to calculate the low DCF result, using instead the minimum EPS growth rate estimate for each proxy company. I then calculated the mean and median low, mean, and high results for the proxy group. In developing my ROE recommendation, I rely on the average of the mean and median proxy group Constant Growth DCF results (*see* Table 4, below, and Nelson Direct Exhibit 2). In doing so, I consider the DCF results of each proxy company without giving undue weight to outliers on either the high or the low side.

Table 4: Constant Growth DCF Results[29]

	Low	Mean	High
30-Day Average	9.47%	10.13%	10.98%
90-Day Average	9.51%	10.25%	10.92%
180-Day Average	9.56%	10.23%	10.89%

2. Quarterly Growth DCF Model

Q. PLEASE BRIEFLY DESCRIBE THE QUARTERLY GROWTH DCF MODEL.

A. As noted earlier, the Constant Growth DCF model is based on several limiting assumptions, one of which is that dividends are paid annually. However, most dividend-paying companies, including utilities, pay dividends on a quarterly (as opposed to an annual) basis. Although the adjusted dividend yield discussed earlier is meant to address that assumption (by increasing the observed dividend yield by one-half of the expected growth rate), it does not fully reflect the quarterly receipt and reinvestment of dividends. As a consequence, the Constant Growth DCF model likely understates the Cost of Equity. The Quarterly Growth DCF model specifically incorporates investors' expectations of the quarterly payment of dividends, and the associated quarterly compounding of those dividends as they are reinvested at the required ROE. As noted by Dr. Roger Morin:

> Clearly, given that dividends are paid quarterly and that the observed stock price reflects the quarterly nature of dividend payments, the market-required return must recognize quarterly

[29] Nelson Direct Exhibit 2. Average of the mean and median proxy group results.

> compounding, for the investor receives dividend checks and reinvests the proceeds on a quarterly schedule ... The annual DCF model inherently understates the investors' true return because it assumes all cash flows received by investors are paid annually.[30]

Q. HOW IS THE DIVIDEND YIELD PORTION OF THE QUARTERLY DCF MODEL CALCULATED?

A. To more accurately reflect the timing and compounding of quarterly dividends, the model replaces the "D" component of the Constant Growth DCF model with the following equation:

$$D = d_1(1+k)^{0.75} + d_2(1+k)^{0.50} + d_3(1+k)^{0.25} + d_4(1+k)^{0} \quad [3]$$

where:

d_1, d_2, d_3, d_4 = expected quarterly dividends over the coming year; and

k = the required Return on Equity.

Because the required ROE (k) is a variable in the dividend calculation, the Quarterly Growth DCF model is solved iteratively.

To calculate the expected dividends over the coming year for the proxy companies (*i.e.*, d_1, d_2, d_3, and d_4), I obtained the last four paid quarterly dividends for each company and multiplied them by one plus the growth rate (*i.e.,* $1 + g$). For the P_0 component of the dividend yield, I used the same average stock prices applied in the Constant Growth DCF analysis (*i.e.*, 30-, 90-, and 180-trading day averages ended February 26, 2021) for each proxy company.

[30] Roger A. Morin, Ph.D., New Regulatory Finance, Public Utility Reports, Inc., 2006 at 344.

Q. WHAT ARE THE RESULTS OF YOUR QUARTERLY GROWTH DCF ANALYSES?

A. My Quarterly Growth DCF results are summarized in Table 5, below (*see also* Nelson Direct Exhibit 3). As with my Constant Growth DCF results, I exclude high and low outlier growth rates and rely on the average of the mean median proxy group results.

Table 5: Quarterly Growth DCF Results[31]

	Low	**Mean**	**High**
30-Day Average	9.63%	10.32%	11.14%
90-Day Average	9.67%	10.41%	11.08%
180-Day Average	9.73%	10.37%	11.12%

3. Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

Q. PLEASE DESCRIBE THE GENERAL FORM OF THE CAPM.

A. The CAPM is a risk premium method that estimates the Cost of Equity for a given security as a function of a risk-free return plus a risk premium (to compensate investors for the non-diversifiable or "systematic" risk of that security). The CAPM describes the relationship between a security's investment risk and the market rate of return. The CAPM assumes that all non-market or unsystematic risk, can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic risk. In addition, the CAPM presumes that investors require compensation only

[31] Nelson Direct Exhibit 3. Average of the mean and median proxy group results.

for systematic risk that is the result of macroeconomic and other events that affect the returns on all assets.

As shown in Equation [4], the CAPM is defined by four components, each of which theoretically must be a forward-looking estimate:

$$K_e = r_f + \beta(r_m - r_f) \qquad [4]$$

where:

K_e = the required market ROE for a security;

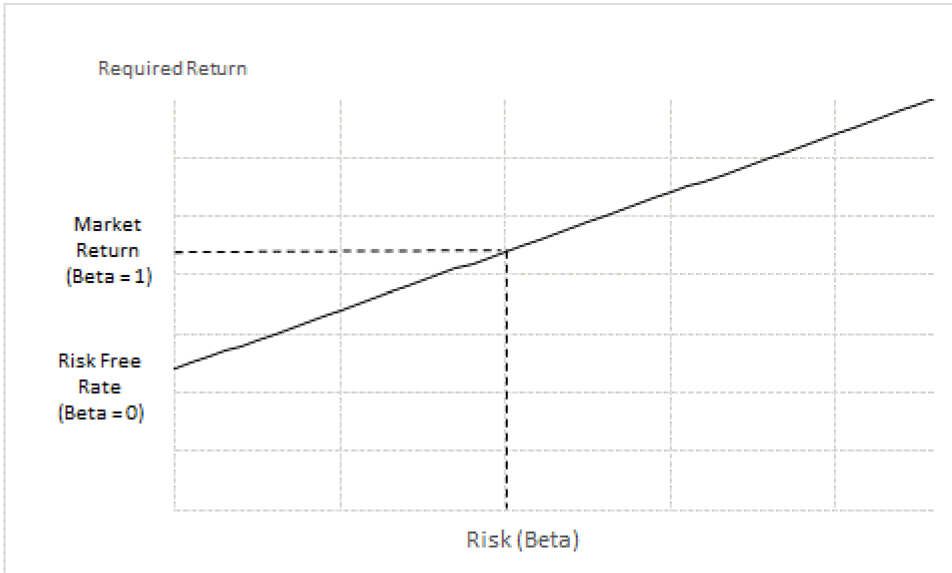
β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

Equation [4] describes the Security Market Line ("SML"), or the CAPM risk-return relationship, which is graphically depicted in Chart 1 below. The intercept is the risk-free rate (r_f) which has a Beta coefficient of zero, and the slope is the expected market risk premium ($r_m - r_f$). By definition, r_m, the return on the market, has a Beta coefficient of 1.00. CAPM states that in well-behaving capital markets, the expected equity risk premium on a given security is proportional to its Beta coefficient.

Chart 1: Security Market Line



Intuitively, higher Beta coefficients indicate that the subject company's returns have been relatively volatile and have moved in tandem with the overall market. Consequently, if a company has a Beta coefficient of 1.00, it is as risky as the market and does not provide any diversification benefit.

In Equation [4], the term $(r_m - r_f)$ represents the Market Risk Premium.[32] According to the theory underlying the CAPM, since unsystematic risk can be diversified away by adding securities to investment portfolios, the market will not compensate investors for bearing that risk. Therefore, under the CAPM theory, investors should be concerned only with systematic or non-diversifiable risk. Non-diversifiable risk is measured by the Beta coefficient, which is defined as:

[32] The Market Risk Premium is defined as the incremental return of the market portfolio over the risk-free rate.

$$\beta_j = \frac{\sigma_j}{\sigma_m} \text{ x } \rho_{j,m} \quad [5]$$

where σ_j is the standard deviation of returns for company "j," σ_m is the standard deviation of returns for the broad market (as measured, for example, by the S&P 500 Index), and $\rho_{j,m}$ is the correlation of returns in between company j and the broad market. The Beta coefficient, therefore, represents both relative volatility (*i.e.*, the standard deviation) of returns, and the correlation in returns between the subject company and the overall market.

Q. WHAT RISK-FREE RATES DO YOU ASSUME IN YOUR CAPM ANALYSIS?

A. I used two different estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (*i.e.*, 1.97 percent)[33] and (2) a projected 30-year Treasury yield (*i.e.*, 2.72 percent).[34]

Q. WHY HAVE YOU RELIED ON THE 30-YEAR TREASURY YIELD IN YOUR CAPM ANALYSIS?

A. In determining the security most relevant to the application of the CAPM, it is important to select the term (or maturity) that best matches the life of the underlying investment. Natural gas utilities are typically long-duration investments and, as such, the 30-year Treasury yield is more suitable for the purpose of calculating the Cost of Equity.

---

[33] Source: Bloomberg Professional Service.

[34] The average of: (1) the average projected 30-year Treasury yield for the six quarters ended Q2 2022 and (2) the long-term projected 30-year Treasury yield for the years 2022-2026 and 2027-2031 reported by *Blue Chip Financial Forecasts. See, Blue Chip Financial Forecasts* Vol. 40, No. 3, March 1, 2021, at 2 and *Blue Chip Financial Forecasts,* Vol. 39, No. 12, December 1, 2020, at 14.

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

A. It is my usual practice to consider the Beta coefficients reported by two sources: Bloomberg and *Value Line*. Both of those services adjust their calculated (or "raw") Beta coefficients to reflect the tendency of the Beta coefficient to regress toward the market mean of 1.00; *Value Line* calculates the Beta coefficient over a five-year period, while Bloomberg's calculation is based on two years of data. The proxy group mean and median Beta coefficients from *Value Line* and Bloomberg are shown in Table 6 below.

Table 6: Proxy Group Beta Coefficients[35]

	Value Line	**Bloomberg**
Proxy Group Average	0.886	0.949
Proxy Group Median	0.850	0.959

To be conservative, I have relied on the *Value Line* Beta coefficients in my CAPM and ECAPM analyses presented in my Direct Testimony.

Q. PLEASE DESCRIBE YOUR FORWARD-LOOKING (*I.E.*, *EX-ANTE*) APPROACH TO ESTIMATING THE MARKET REQUIRED RETURN.

A. It is my usual practice to develop two estimates of the market required return by calculating the market capitalization-weighted average ROE based on the Constant Growth DCF model for the S&P 500 companies using data from Bloomberg and *Value Line* (*see* Nelson Direct Exhibit 4). With respect to Bloomberg-derived growth estimates, I calculated the expected dividend yield (using the same one-half growth rate assumption described earlier) and

[35] Sources: *Value Line* and Bloomberg Professional Service as of February 26, 2021.

combined that amount with the projected earnings growth rate to arrive at the market capitalization weighted average DCF result. I performed that calculation for each of the S&P 500 companies for which Bloomberg provided consensus growth rates, which produces an expected market required return of 16.35 percent. In the case of *Value Line*, I performed the same calculation, again using all companies for which five-year earnings growth rates were available, which produces an expected market required return of 14.34 percent.

While my usual practice is to apply the average of the Bloomberg-derived and *Value Line*-derived expected market return estimates, in order to be conservative, my CAPM and ECAPM analyses presented in my Direct Testimony rely on the more conservative *Value Line*-derived expected market return estimate.

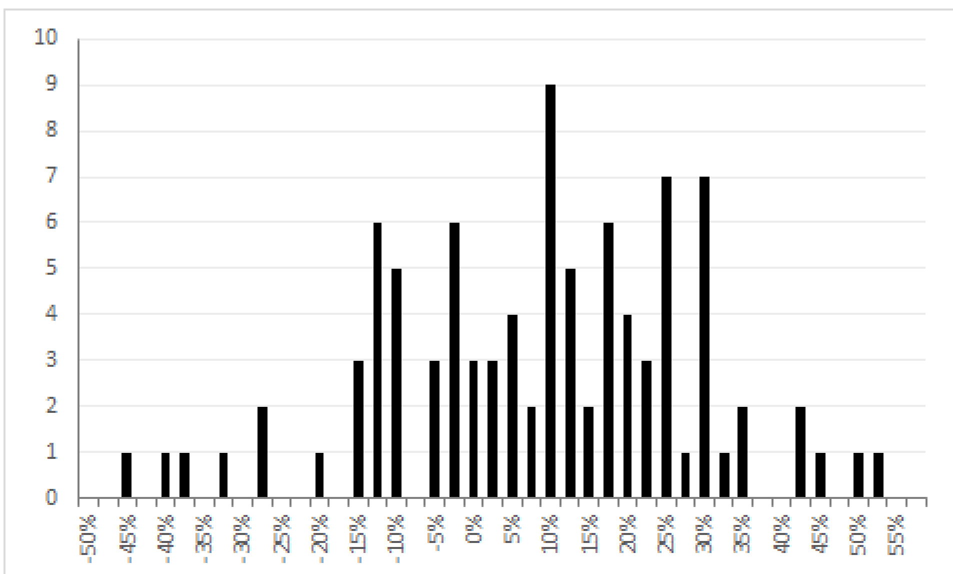
Q. WITH THE RISK-FREE RATES AND *EX-ANTE* MARKET REQUIRED RETURN ESTIMATES DESCRIBED ABOVE, HOW DID YOU CALCULATE THE MARKET RISK PREMIUM ("MRP")?

A. Because I apply two estimates of the risk-free rate, I calculated two estimates of the MRP. The first MRP estimate takes the *Value Line ex-ante* market required return described above (14.34 percent) and subtract the current 30-day average 30-year Treasury yield (1.97 percent). My second MRP estimate subtracts the projected 30-year Treasury yield (2.72 percent) *Value Line ex-ante* market required return (14.34 percent). These calculations result in *ex-ante* MRP estimates using the current and projected 30-year Treasury yield of 12.37 percent and 11.62 percent, respectively.

Q. HAVE YOU UNDERTAKEN ANY ANALYSES TO DETERMINE THE REASONABLENESS OF THE *EX-ANTE* MRP ESTIMATES?

A. Yes. To do so, I considered how often various ranges of MRPs have been observed over the 1926 to 2019 period. To perform that analysis, I gathered the annual Market Risk Premia reported by Duff & Phelps and produced a histogram of those observations. The results of that analysis, which are presented in Chart 2, below, demonstrate that MRPs in the range of approximately 12.00 percent (the average of my MRP estimates) and higher occurred quite frequently, approximately 42.00 percent of the time.

Chart 2: Frequency Distribution of MRP, 1926-2019[36]



[36] Source: Duff & Phelps, 2020 SBBI, Appendix A-1, A-7.

Q. WHAT ARE THE RESULTS OF YOUR CAPM ANALYSIS?

A. As shown in Table 7, the proxy group average and median CAPM results suggest an ROE range of 12.48 percent to 13.01 percent (*see* Nelson Direct Exhibit 5).

Table 7: Summary of CAPM Results[37]

	Current 30-Year Treasury Yield (1.97%)	Projected 30-Year Treasury Yield (2.72%)
Proxy Group Average	12.92%	13.01%
Proxy Group Median	12.48%	12.59%

Q. DID YOU CONSIDER ANOTHER FORM OF THE CAPM IN YOUR ANALYSIS?

A. Yes. I also consider the Empirical CAPM ("ECAPM") approach, which calculates the product of the adjusted Beta coefficient and the Market Risk Premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the Market Risk Premium, without any effect from the Beta coefficient.[38] The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [6] below:

$$k_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \qquad [6]$$

where:

[37] Nelson Direct Exhibit 5.

[38] *See, e.g.*, Roger A. Morin, Ph.D., New Regulatory Finance, at 189-190 (2006).

k_e = the required market ROE;

β = the adjusted Beta coefficient of an individual security;

r_f = the risk-free rate of return; and

r_m = the required return on the market as a whole.

Q. WHAT IS THE BENEFIT OF THE ECAPM APPROACH?

A. The ECAPM addresses the tendency of the CAPM to under-estimate the Cost of Equity for companies, such as regulated utilities, with low Beta coefficients. As discussed below, the ECAPM recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM under-estimates the alpha, or the constant return term.[39]

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. The ECAPM method reflects the finding that the actual SML described by the CAPM formula is not as steeply sloped as the predicted SML.[40] Fama and French state that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[41] Similarly, Morin states:

> With few exceptions, the empirical studies agree that . . . low-beta securities earn returns somewhat higher than the CAPM

[39] *Ibid*., at 191 ("The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks.").

[40] *Ibid*., at 175. The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on the X-axis.

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

would predict, and high-beta securities earn less than predicted. . . .

Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:

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

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:

$$K = R_F + 0.25(R_M - R_F) + 0.75\,\beta(R_M - R_F)$$ [42]

Q. DOES THE APPLICATION OF ADJUSTED BETA COEFFICIENTS IN THE ECAPM ADDRESS THE EMPIRICAL ISSUES WITH THE CAPM?

A. No, it does not. Beta coefficients are adjusted because of their general regression tendency to converge toward 1.00 over time, *i.e.*, over successive calculations. As also noted earlier, numerous studies have determined that at any given point in time, the SML described by the CAPM formula is not as steeply sloped as the predicted SML. To that point, Morin states:

Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence.

[42] Roger A. Morin, Ph.D., New Regulatory Finance, at 175, 190 (2006).

> The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary.[43]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM. As with the CAPM, my application of the ECAPM uses the Market DCF-derived *ex-ante* market return estimate from *Value Line*, the current and projected yield on 30-year Treasury securities as the risk-free rate, and *Value Line's* Beta coefficient. The results of my ECAPM analyses are shown on Nelson Direct Exhibit 5 and summarized in Table 8 below.

Table 8: Summary of ECAPM Results[44]

	Current 30-Year Treasury Yield (1.97%)	Projected 30-Year Treasury Yield (2.72%)
Proxy Group Average	13.28%	13.34%
Proxy Group Median	12.95%	13.03%

4. Bond Yield Plus Risk Premium Approach

Q. PLEASE DESCRIBE THE BOND YIELD PLUS RISK PREMIUM APPROACH.

A. The Bond Yield Plus Risk Premium approach is based on the basic financial principle of risk and return; that is, equity investors require a premium over the

[43] *Ibid.*, at 191.

[44] Nelson Direct Exhibit 5.

return they would have earned as a bondholder to account for the residual risk associated with equity ownership. In other words, since returns to equity holders are riskier than returns to bondholders, equity investors must be compensated for bearing that additional risk. Risk premium approaches, therefore, estimate the Cost of Equity as the sum of the equity risk premium and the yield on a particular class of bonds.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS.

A. I first defined the Equity Risk Premium as the difference between the authorized ROE and the then-prevailing level of long-term (*i.e.*, 30-year) Treasury yield. I gathered the authorized ROE for 1,185 natural gas utility rate proceedings between January 1, 1980, and February 26, 2021. To reflect the prevailing level of interest rates during the pendency of the proceedings, I calculated the average 30-year Treasury yield over the average period between the filing of the rate case and the date of the final order (approximately 187 days).

Because the data covers several economic cycles, the analysis is helpful in assessing the change in the Equity Risk Premium over time. Prior research, for example, has shown that the Equity Risk Premium is inversely related to the level of interest rates.[45] That analysis is particularly relevant given the relatively low level of current Treasury yields.

Q. HOW DID YOU ANALYZE THE RELATIONSHIP BETWEEN INTEREST RATES AND THE EQUITY RISK PREMIUM?

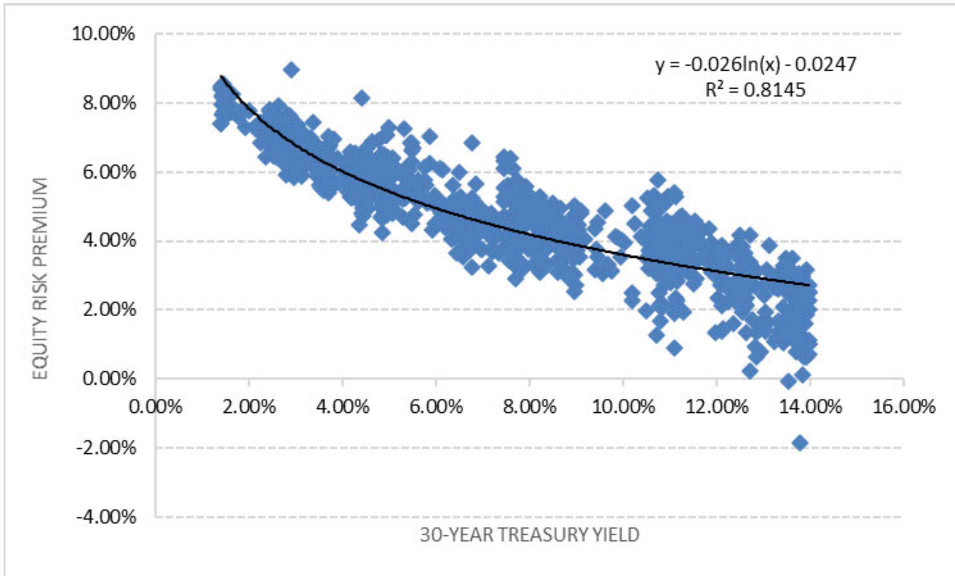
A. I estimated the relationship between interest rates and the Equity Risk Premium by applying a regression analysis, in which the observed Equity Risk Premium described above is the dependent variable, and the average 30-year Treasury yield is the independent variable. To account for the variability in interest rates and authorized ROEs over several decades, I used the semi-log regression, in which the Equity Risk Premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$\text{RP} = \alpha + \beta\left(LN(T_{30})\right) \quad [7]$$

As shown on Chart 3 (below), the semi-log form is useful when measuring an absolute change in the dependent variable (in this case, the Equity Risk Premium) relative to a proportional change in the independent variable (the 30-year Treasury yield).

[45] *See*, *for example*, Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management, (Summer 1992), at 63-70; 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 33-45; and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management, (Autumn 1995), at 89-95.

Chart 3: Equity Risk Premium[46]



As Chart 3 illustrates, the Equity Risk Premium increases as interest rates fall. The finding that the Equity Risk Premium and interest rates are inversely related is supported by published research. For example, Dr. Roger Morin notes that: "… [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when interest rates rose."[47] Based on the regression coefficients in Chart 3, the implied ROE is between 9.75 percent and 9.86 percent (*see* Table 9 and Nelson Direct Exhibit 6).

---

[46] Nelson Direct Exhibit 6.

[47] Roger A: Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 128 [clarification added].

Table 9: Summary of Bond Yield Plus Risk Premium Results[48]

	Return on Equity
Current 30-Year Treasury (1.97%)	9.86%
Projected 30-Year Treasury (2.72%)	9.75%

IV. SMALL SIZE PREMIUM

Q. DID YOU CONSIDER ADDITIONAL FACTORS WHEN DEVELOPING YOUR RANGE OF THE COST OF EQUITY FOR PSNC?

A. Yes, I did. As explained below, PSNC's small size relative to the proxy group must be taken into consideration when determining where its Cost of Equity falls within the range of results.

Q. PLEASE EXPLAIN THE RISK ASSOCIATED WITH SMALL SIZE.

A. Both the financial and academic communities have long accepted the proposition that the Cost of Equity for small firms is subject to a "size effect."[49] Although empirical evidence of the size effect often is based on studies of industries beyond regulated utilities, utility analysts also have noted the risks associated with small market capitalizations. Specifically, an analyst from Ibbotson Associates noted:

> For small utilities, investors face additional obstacles, such as a smaller customer base, limited financial resources, and a lack of diversification across customers, energy sources, and geography. These obstacles imply a higher investor return.[50]

---

[48] Nelson Direct Exhibit 6.

[49] Mario Levis, *The record on small companies: A review of the evidence*, Journal of Asset Management, March 2002, at 368-397, for a review of literature relating to the size effect.

[50] Michael Annin, *Equity and the Small-Stock Effect*, Public Utilities Fortnightly, October 15, 1995.

Small size, therefore, leads to two categories of increased risk for investors: (1) liquidity risk (*i.e.*, the risk of not being able to sell one's shares in a timely manner due to the relatively thin market for the securities); and (2) fundamental business risks.

Q. HOW DOES THE COMPARATIVELY SMALL SIZE OF PSNC AFFECT ITS BUSINESS RISKS RELATIVE TO THE PROXY GROUP OF COMPANIES?

A. In general, smaller utility companies are less able to withstand adverse events that affect their revenues and expenses. Capital expenditures for non-revenue producing investments such as system maintenance and replacements will put proportionately greater pressure on customer costs, potentially leading to customer attrition or demand reduction. These risks affect the return required by investors for smaller companies.

Q. IS THERE SUPPORT IN THE FINANCIAL COMMUNITY FOR THE USE OF A SMALL SIZE PREMIUM?

A. Yes. There have been several studies that demonstrate the existence of the size premium. One of the earliest works in this area found that over a period of 40 years "the common stock of small firms had, on average, higher risk-adjusted returns than the common stock of large firms."[51] The author, who referred to that finding as the "size effect," suggested that the CAPM was mis-specified, in that on average, smaller firms had significantly larger risk-adjusted returns

[51] R. W. Banz, *The Relationship Between Return and Market Value of Common Stocks*, Journal of Financial Economics, 9, 1981.

than larger firms. The author also concluded that the size effect was "most pronounced for the smallest firms in the sample."[52] Since then, additional empirical research has focused on explaining the size effect as a function of lower trading volume and other factors, but the proposition that Beta coefficients fail to reflect the risks of smaller firms persists.[53]

In 1994, Fama and French focused on the issue of whether the CAPM adequately explained security returns and proposed a "three factor" model for expected security returns. Those factors include: (1) the covariance with the market, (2) size, and (3) financial risk as determined by the book-to-market ratio. As explained by Morningstar, Fama and French "found that the returns on stocks are better explained as a function of size and book-to-market value in addition to the single market factor of the CAPM, with the company's size capturing the size effect and its book-to-market ratio capturing the financial distress of a firm."[54]

Q. IS IT APPROPRIATE TO CONSIDER THE RISK ASSOCIATED WITH PSNC'S SMALL SIZE EVEN THOUGH IT IS A SUBSIDIARY OF DEI?

A. Yes. The widely accepted "stand-alone" regulatory principle treats each utility subsidiary as its own company. Parent entities, like other investors, have capital constraints and must look at the attractiveness of the expected risk-adjusted

---

[52] *Ibid.*

[53] *See,* e.g. Mario Levis, *The record on small companies: A review of the evidence*, Journal of Asset Management, March, 2002.

[54] Morningstar, Ibbotson SBBI 2013 Valuation Yearbook, at 109.

return of each investment alternative in their capital budgeting process. The opportunity cost concept applies regardless of the source of the 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 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, as well as with other, similarly situated utility 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. Therefore, it is important that the authorized ROE reflects the risks and prospects of the regulated utility's operations and supports the regulated utility's financial integrity from a stand-alone perspective.

Q. HOW DOES PSNC COMPARE IN SIZE TO THE PROXY COMPANIES?

A. Relative to the proxy group, PSNC is smaller in terms of both average customers and market capitalization. Because PSNC is not a separately traded entity, an estimated stand-alone market capitalization for PSNC must be calculated. Nelson Direct Exhibit 7 estimates the implied market capitalization for PSNC. The implied market capitalization of PSNC is calculated by multiplying the median market-to-book ratio for the proxy group of 1.62 to the Company's implied total common equity of $961.50 million.[55] The implied market capitalization based on that calculation is approximately $1,559.57

[55] Equity value of PSNC is estimated from the proposed test year rate base in Schedule B and requested equity ratio.

million. To provide another perspective of the relative size difference, the proxy group median market capitalization is $3.50 billion, which is approximately 2.24 times PSNC's implied market capitalization.

Q. HOW DID YOU ESTIMATE THE SIZE PREMIUM FOR PSNC?

A. In its *Cost of Capital Navigator*, Duff & Phelps presents its calculation of the size premium for deciles of market capitalizations relative to the S&P 500 Index. An additional estimate of the size premium associated with PSNC, therefore, is the difference in the Duff & Phelps size risk premiums for the proxy group median market capitalization relative to the implied market capitalization for PSNC.

As shown on Nelson Direct Exhibit 7, based on recent market data, the median market capitalization of the proxy group was approximately $3.50 billion, which corresponds to the fifth decile of Duff & Phelps's market capitalization data. Based on the Duff & Phelps analysis, that decile has a size premium of 1.09 percent (or 109 basis points). The implied market capitalization for PSNC is approximately $1,559.57 million, which falls within the 7th decile and corresponds to a size premium of 1.54 percent (or 154 basis points). The difference between those size premiums is 45 basis points (1.54 percent – 1.09 percent).

Q. HAVE YOU CONSIDERED THE COMPARATIVELY SMALL SIZE OF PSNC IN YOUR ROE RECOMMENDATION?

A. Yes. While I have quantified the small size effect, rather than proposing a specific premium, I have considered the small size of PSNC in order to determine where, within a reasonable range of returns, PSNC's required ROE appropriately falls.

V. ECONOMIC CONDITIONS IN NORTH CAROLINA

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 that the Commission must balance the interests of investors and customers in setting the ROE. 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."[56] 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

[56] 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*, October 23, 2013 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.").

> constitutional proscriptions against confiscation of property. This is in accord with the "end result" test of <u>Hope</u>. This the Commission has done.[57]

The North Carolina Supreme Court agreed, and upheld the Commission's Order on Remand.[58] The North Carolina Supreme Court has also made clear that the Commission "must make findings of fact regarding the impact of changing economic conditions on customers when determining the proper ROE for a public utility."[59] 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 consumers",[60] which the Commission made in its Order on Remand.[61] In light of the *Cooper II* decision and the North Carolina Supreme Court precedent that preceded it,[62] 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.

---

[57] State of North Carolina Utilities Commission, Docket No. E-7, Sub 989, *Order on Remand*, October 23, 2013, at 34 - 35; *see also,* State of North Carolina Utilities Commission, Docket No. E-22, Sub 479, *Order on Remand*, July 23, 2015 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").

[58] *See, State of North Carolina ex rel. Utilities Commission v. Cooper*, 367 N.C. 644, 766 S.E.2d 827 (Dec. 2014).

[59] *State of North Carolina ex rel. Utilities Commission v. Cooper*, 366 N.C. 484, 739 S.E.2d 548 (April 2013) ("*Cooper I*").

[60] *State of North Carolina ex rel. Utilities Commission v. Cooper*, 367 N.C. 430, 758 S.E.2d 635, 643 (June 2014) ("*Cooper II*").

[61] *See,* State of North Carolina Utilities Commission, Docket No. E-22, Sub 479, *Order on Remand*, at 4-10.

[62] *See*, *Cooper I.*

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 Equity.[63] 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;
- 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. Additionally, the overall cost of living in North Carolina also is below the national average, including the District of Columbia and Puerto Rico. Lastly, at the national level, income has generally been increasing since the 2008/2009 financial crisis.

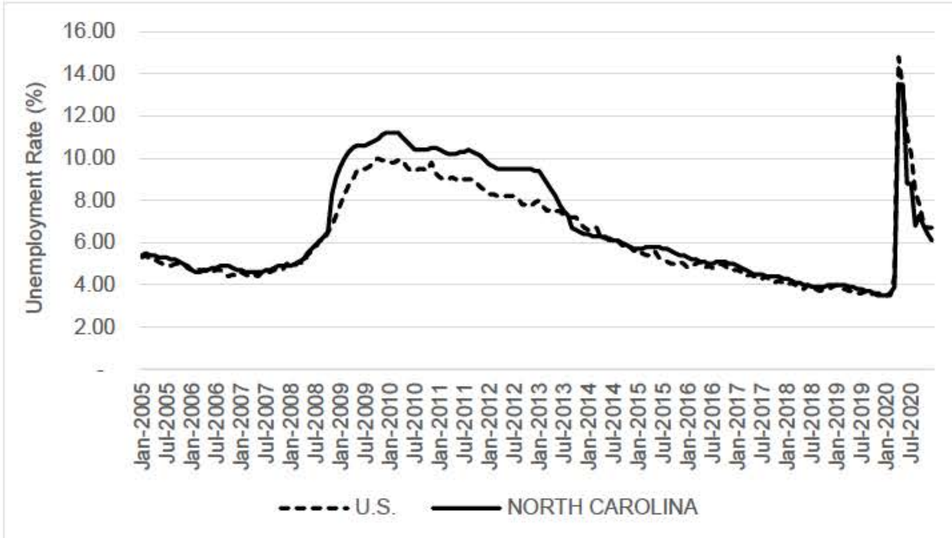
[63] *See,* State of North Carolina Utilities Commission, Docket No. E-22, Sub 479, *Order on Remand*, July 23, 2015, at 39.

On balance, the correlations between statewide measures of economic conditions noted by the Commission in Docket No. E-22, Sub 479 remain in place and, as such, they continue to be reflected in the models used to estimate the Cost of Equity.

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, unemployment 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 recent unemployment rate has fared better than the overall U.S., even as both fell considerably by the end of 2020 (*see* Chart 4, below).

Chart 4: Unemployment Rate (Seasonally Adjusted)[64]



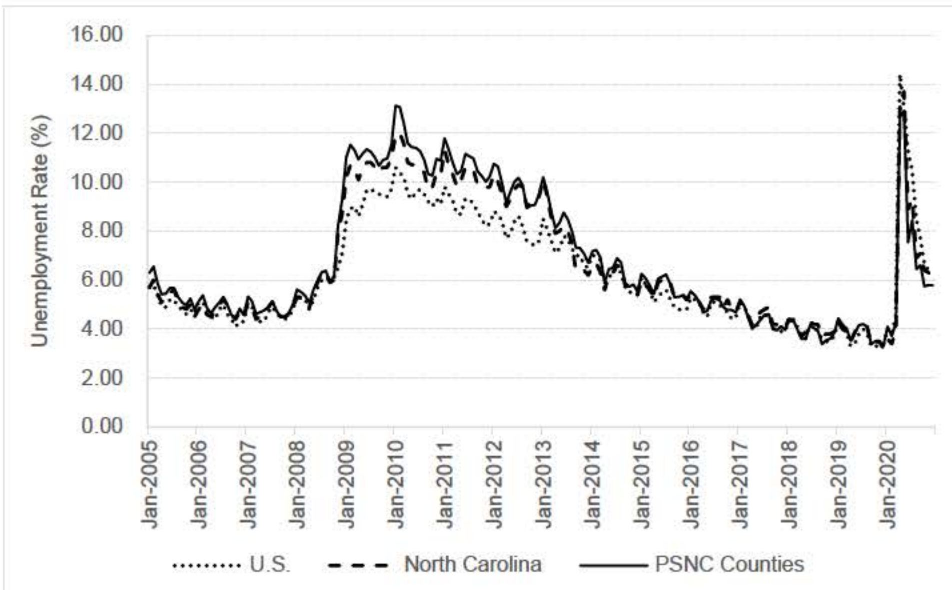
Between 2005 and 2020, the correlation between North Carolina's unemployment rate and the national rate was 97.20 percent, indicating the two are highly correlated.

Second, I reviewed seasonally unadjusted unemployment rates in the counties served by PSNC. As with the seasonally adjusted statistics described above, the seasonally unadjusted unemployment rate in those counties spiked in April 2020, peaking in May 2020 at 12.90 percent (below both the national and state-wide averages of 13.00 percent and 13.70 percent, respectively, in May 2020), but by December 2020 it had fallen substantially to 5.78 percent, below both the rate state-wide in North Carolina (6.10 percent) and for the overall U.S. (6.50 percent). From 2005 through December 2020, the correlation in seasonally unadjusted unemployment rates between the counties served by

[64] Source: Bureau of Labor Statistics.

PSNC and the U.S., as well as North Carolina statewide, was approximately 95.79 percent and 99.33 percent, respectively. In summary, county-level unemployment (1) has fallen considerably since spiking in April and May 2020, (2) remains below both the U.S. and statewide unemployment rates, and (3) is highly correlated to state and national unemployment rates.

Chart 5: Seasonally Unadjusted Unemployment Rates[65]

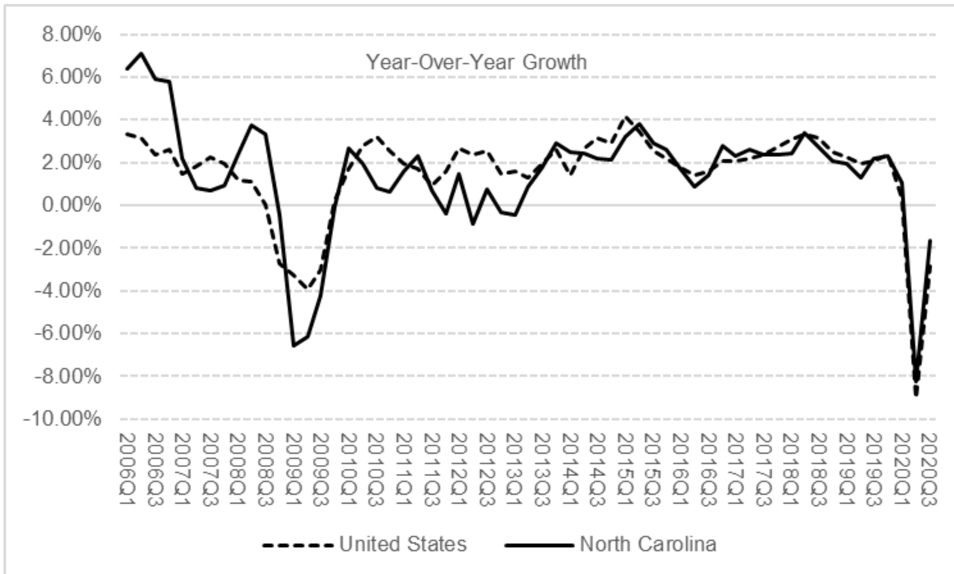


Looking to real Gross Domestic Product growth, there also has been a strong correlation between North Carolina and the national economy (approximately 81.51 percent). While the national rate of GDP growth at times outpaced North Carolina's GDP growth between 2010 and 2014, since the first quarter of 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

[65] Source: Bureau of Labor Statistics; Federal Reserve Bank of St. Louis FRED Economic Data.

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.

Chart 6: Real Gross Domestic Product Growth Rate (Year over Year)[66]



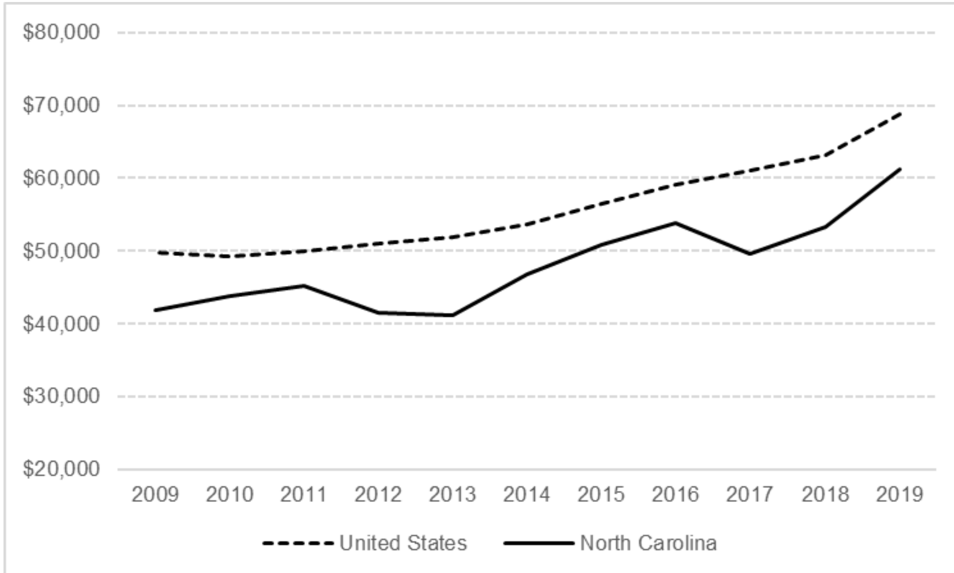
As to median household income, the correlation between North Carolina and the U.S. is strong (94.00 percent from 2005 through 2019). Since 2009 (that is, subsequent to the 2008/2009 financial crisis), nominal median household income in North Carolina has grown at a faster pace than the national median income (compound annual growth rate of 3.85 percent vs. 3.27 percent, respectively; *see* Chart 7, below). To put household income in perspective, the Missouri Economic Research and Information Center reports that in 2020, North Carolina had the 24th lowest cost of living index among the 50 states, the District of Columbia, and Puerto Rico.[67]

---

[66] Source: Bureau of Economic Analysis.

[67] Source: meric mo.gov/data/cost-living-data-series accessed March 7, 2021.

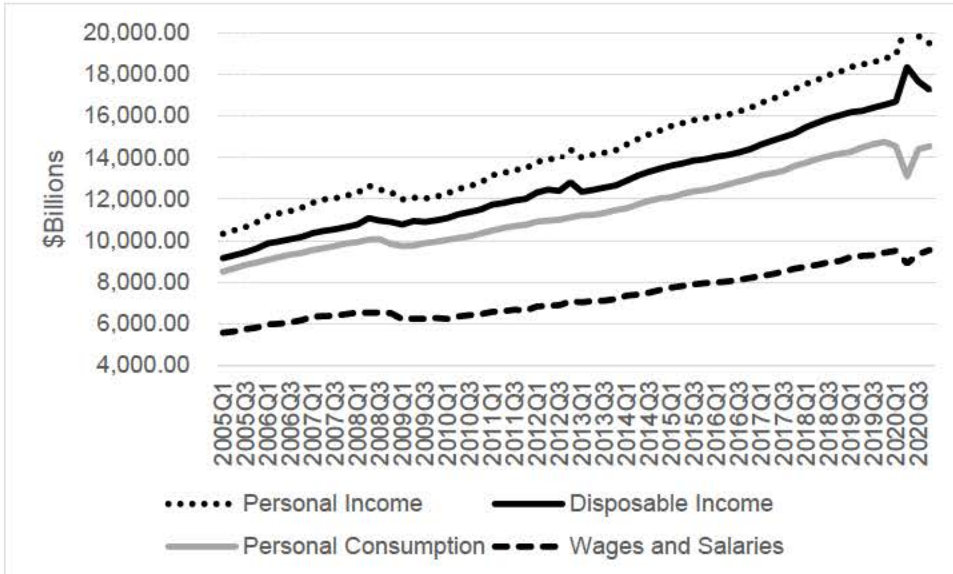
Chart 7: Median Household Income[68]



Similarly, as shown in Chart 8, 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.

[68] Source: U.S. Census Bureau, Current Population Survey. Nominal dollars.

Chart 8: United States Income and Consumption[69]



Q. PLEASE SUMMARIZE THE ECONOMIC INDICATORS THAT YOU ANALYZED AND REVIEWED 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 PSNC have fallen by half since spiking in April and May 2020;
- The state's real Gross Domestic Product remains highly correlated with national GDP; and
- Since 2005, median household income has grown in North 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

[69] Source: Bureau of Economic Analysis.

(including the District of Columbia and Puerto Rico). Lastly, at the national level, income has generally been increasing since the 2008/2009 financial crisis, and has rebounded since dropping in the second quarter of 2020.

The U.S. and North Carolina economies both experienced a 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 PSNC'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 PERCENT FAIR AND REASONABLE TO PSNC, ITS SHAREHOLDERS, AND ITS CUSTOMERS, AND NOT UNDULY BURDENSOME TO PSNC'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 percent is fair and reasonable to PSNC, its shareholders, and its customers in light of the changing economic conditions.

VI. CAPITAL MARKET ENVIRONMENT

Q. DO ECONOMIC CONDITIONS INFLUENCE THE REQUIRED COST OF CAPITAL AND REQUIRED RETURN ON COMMON EQUITY?

A. Yes. The required Cost of Capital, including the ROE, is a function of prevailing and expected economic and capital market conditions. As discussed below, the models used to estimate the Cost of Equity are influenced by current and expected capital market conditions. In addition, all analytical models used to estimate the required ROE are based on simplifying assumptions that may not hold true under specific market circumstances. Therefore, it is important to assess the reasonableness of any financial model's results in the context of observable market data. To the extent that certain ROE estimates are incompatible with such data or inconsistent with basic financial principles, it is appropriate to consider whether alternative estimation methods are likely to provide more meaningful and reliable results.

Q. PLEASE DESCRIBE THE RECENT CAPITAL MARKET DISLOCATION AND ITS IMPLICATIONS FOR ESTIMATING THE COMPANY'S COST OF EQUITY.

A. It is well recognized that there have been dramatic shifts in the capital markets brought about by the COVID-19 pandemic. The speed and severity of the increase in risk and the loss in value cut across all market sectors, including utilities. Notably:

- From February 12 to March 23, 2020, the Standard & Poor's ("S&P") 500 Index lost approximately 34.00 percent of its value, as did the utility sector.[70]

[70] Source: Yahoo! Finance. Utility sector measured by the XLU and Dow Jones Utility Average.

- At the same time, the Chicago Board Options Exchange ("CBOE") Volatility Index ("VIX"), a measure of expected market volatility, increased six-fold (from 13.68 on February 14, 2020 to 82.69 on March 16, 2020).[71]
- On March 9, 2020, the 30-year Treasury yield fell below 1.00 percent for the first time.[72]

Although government and central bank actions have stabilized the capital markets somewhat, as explained in more detail below, volatility (and, therefore, risk) remain elevated for the utility sector, which has important implications on ROE analyses.

Q. IS THERE A RELATIONSHIP BETWEEN EQUITY MARKET VOLATILITY AND INTEREST RATES?

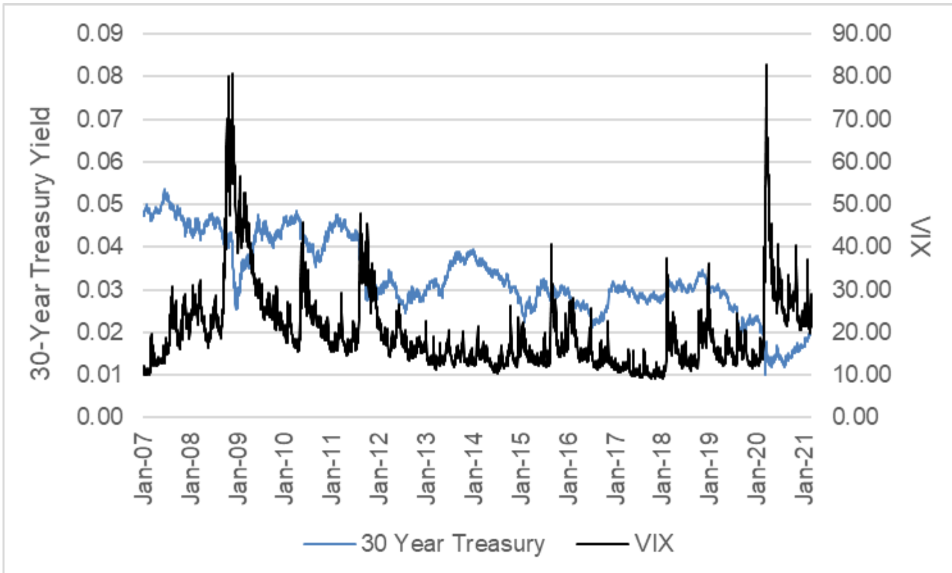
A. Yes, there is. Significant and abrupt increases in volatility tend to be associated with declines in Treasury yields. That relationship makes intuitive sense; as investors see increasing risk, their objectives may shift principally to capital preservation (that is, avoiding a capital loss). A means of doing so is to allocate capital to the relative safety of Treasury securities, in a "flight to safety." Because Treasury yields tend to be inversely related to Treasury bond prices, as investors bid up the prices of bonds, they bid down the yields. As Chart 9 below demonstrates, decreases in the 30-year Treasury yield are coincident with significant increases in the VIX. In those instances, the decline in yields does

[71] Source: Bloomberg Professional Service.

[72] Source: Bloomberg Professional Service.

not reflect a reduction in required returns, it reflects an increase in risk aversion and, therefore, an increase in required equity returns as investors favor the relative security of bonds during volatile markets.

Chart 9: 30-Year Treasury Yields vs. VIX[73]



Q. HAS VOLATILITY REMAINED ELEVATED RELATIVE TO HISOTRICAL LEVELS IN RECENT MONTHS?

A. Yes. A visible and widely reported measure of expected volatility is the VIX. As CBOE explains, the VIX calculation is designed to produce a measure of constant, 30-day expected volatility of the U.S. stock market, derived from real-time, mid-quote prices of S&P 500 Index call and put options.[74] Simply, the VIX is a market-based measure of expected volatility. Because volatility is a measure of risk, increases in the VIX, or in its volatility, are a broad indicator

[73] Source: Bloomberg Professional Service.

[74] Source: www.cboe.com/vix.

of expected increases in market risk. That is, if the level of the VIX stood at 15.00, it would be interpreted as an expected standard deviation in annual market returns of 15.00 percent over the coming 30 days. Since 1990, the VIX has averaged about 19.49, which is consistent with the long-term standard deviation on annual market returns as reported by Duff & Phelps.[75] From February 12, 2020 to February 26, 2021, the VIX averaged 30.08, or more than 54.00 percent above its long-term average.[76] In other words, since the onset of the COVID-19 pandemic, market volatility has been approximately 54.00 percent higher on average than the market's long-term average volatility.

A further measure of market uncertainty is the volatility of the VIX itself. That is, we can look to the expected volatility of volatility, as measured by Chicago Board Options Exchange VVIX Index ("VVIX"), which is a traded index of the expected volatility of the VIX. Over the long-term, the VVIX has averaged approximately 91.11. As Table 10 below shows, the average VVIX in 2020, and so far in 2021, was at its highest level since the index's inception in 2006.

---

[75] Source: Duff & Phelps, 2020 SBBI Yearbook, at 6-17.

[76] Source: Bloomberg Professional Service.

Table 10: Annual Average VVIX (2006-2021)[77]

Calendar Year	Average VVIX
2006	78.75
2007	87.68
2008	81.85
2009	79.78
2010	88.36
2011	92.94
2012	94.84
2013	80.64
2014	83.01
2015	94.82
2016	92.80
2017	90.01
2018	102.26
2019	91.00
2020	118.47
2021	119.01
Average 2006 - 2019	88.77
Average 2020 - Feb 2021	118.54
Average 2006 - Feb 2021	91.11

From a different perspective, the VVIX averaged 88.77 between 2006 and 2019; in 2020 and 2021, the average VVIX was approximately 34.00 percent higher (118.54), indicating that expected volatility is currently well above the long-term average. Stated differently, a relatively high VVIX suggests the VIX might be more volatile in the future, which in turn suggests expectations for higher market volatility in the future.

[77] Source: Bloomberg Professional Service, data through February 26, 2021.

Q. IS MARKET VOLATILITY EXPECTED TO REMAIN ELEVATED IN THE NEAR TERM?

A. Yes. One means of assessing market expectations regarding the future level of volatility is to review CBOE's "Term Structure of Volatility", which is described by CBOE as:

> The implied volatility term structure observed in SPX options markets is analogous to the term structure of interest rates observed in fixed income markets. Similar to the calculation of forward rates of interest, it is possible to observe the option market's expectation of future market volatility through use of the SPX implied volatility term structure.[78]

As shown in Table 11 below, the implied volatility is expected to remain approximately 50.00 percent above historical volatility[79] until at least March 2022.

---

[78] Source: www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data.

[79] The long-term average price of VIX is 19.49, which, as discussed above, is similar to the long-term standard deviation of annual market returns.

Table 11: CBOE Term Structure of Volatility[80]

Date	Projected VIX
March 2021	28.21
April 2021	28.44
May 2021	29.59
June 2021	30.12
July 2021	30.71
August 2021	31.02
September 2021	31.75
December 2021	31.13
January 2022	29.15
March 2022	29.02

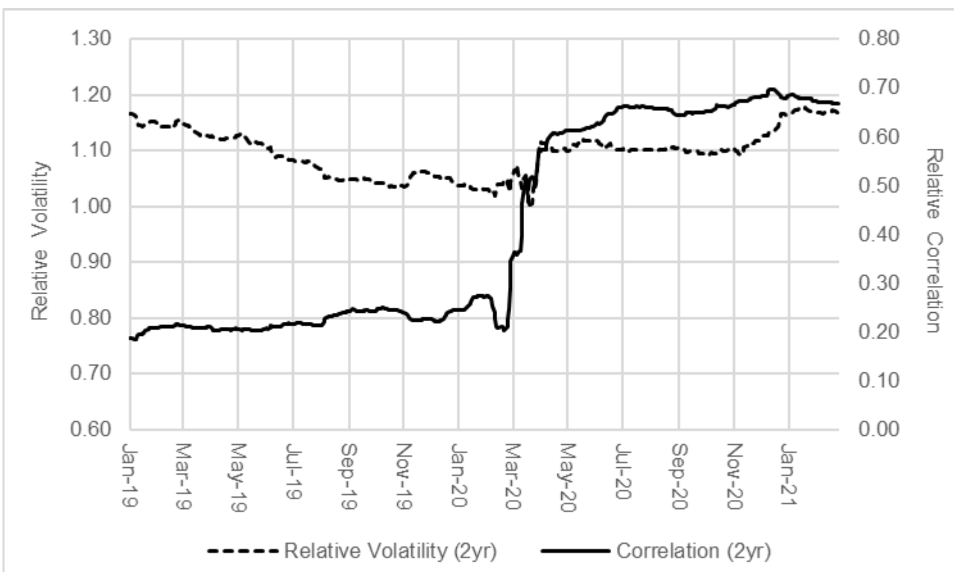
In short, investors reacted to the increase in market volatility associated with the COVID-19 pandemic by moving away from equity securities (including utilities) to Treasury securities, thereby pushing down long-term Treasury yields. Consequently, current levels of interest rates are the result of a volatility-driven "flight to safety" on the part of investors, indicating increased risk aversion, and therefore a corresponding increase in investors' required equity returns. As shown in Chart 9 above, although volatility has declined somewhat from their March 2020 highs (as Treasury yields have begun to increase), it remains – and is expected to remain – above historical levels in the near term.

[80] Source: http://www.cboe.com/trading-tools/strategy-planning-tools/term-structure-data, as of February 26, 2021.

Q. ARE THERE ADDITIONAL MEASURES THAT INDICATE THE COST OF EQUITY HAS INCREASED FOR UTILITIES?

A. Yes. As explained in Section III, Beta coefficients are a function of two parameters: (1) relative volatility (the standard deviation of the subject company's returns relative to the standard deviation of the market return); and (2) the correlation between the subject company's returns and the market return.[81] Under the CAPM, higher Beta coefficients indicate an increase in the Cost of Equity, all else equal. As Chart 10 below demonstrates, both the relative correlation and relative volatility between the proxy group and the overall market (as measured by the S&P 500) increased substantially since March 2020.

Chart 10: Components of Proxy Group (Two-Year) Beta Coefficients[82]



[81] *See*, Equation [5].

[82] Source: S&P Global Market Intelligence. Weekly returns calculated over 24 months.

This increase in correlation between price changes for the proxy group and those for the S&P 500 is not surprising. As Morningstar recently explained, during volatile markets there often is little distinction in returns across assets or portfolios. That is, "correlations go to 1."[83] When that happens, utility stocks lose their "defensive" quality. Not surprisingly, the increased correlation and relative volatility combine to produce significantly increased (adjusted) Beta coefficients. As shown in Table 12, below, the average *Value Line* and Bloomberg Beta coefficients for the proxy group increased by approximately 1.4x and 1.6x, respectively, between February 2020 and February 2021.

Table 12: Average *Value Line* and Bloomberg Proxy Group Beta Coefficients[84]

Date	February 2020	February 2021
Value Line Average	0.629	0.886
Bloomberg Average	0.593	0.949

Q. DOES YOUR RECOMMENDATION ALSO CONSIDER THE INTEREST RATE ENVIRONMENT?

A. Yes, it does. As discussed below, prevailing interest rates have begun to increase. That increase is consistent with expectations for increases in U.S. economic growth and inflation.[85] From an analytical perspective, it is important that the inputs and assumptions used to arrive at an ROE recommendation,

[83] Morningstar, *Correlations Going to 1: Amid Market Collapse, U.S. Stock Fund Factors Show Little Differentiation*, March 6, 2020.

[84] Sources: *Value Line* and Bloomberg Professional Service as of February 28, 2020 and February 26, 2021.

[85] *See, e.g., Blue Chip Financial Forecasts*, Vol. 40, No. 3, March 1, 2021, at 1.

including assessments of capital market conditions, are consistent with the recommendation itself. Because the Cost of Equity is forward-looking, the salient issue is whether investors see the likelihood of increased interest rates during the period in which the rates set in this proceeding will be in effect. With respect to long-term interest rates, the 50 economists surveyed by *Blue Chip Financial Forecasts* ("*Blue Chip*") expect the 30-year Treasury yield to increase from the current 30-day average of 1.97 percent[86] to 2.80 percent on average over the five-year period 2022-2026.[87]

Q. ARE THERE OTHER INDICATIONS THAT INVESTORS EXPECT LONG-TERM INTEREST RATES TO RISE IN THE FUTURE?

A. Yes. Treasury bond prices, and therefore yields, are influenced by inflation expectations. As such, we can look to market data regarding investors' expectations for inflation as an indicator of future Treasury yields. As a recent article in *Barron's* explains, "While all Treasury yields reflect future interest rate expectations and inflation risk, longer-term securities' performance is more sensitive to rising interest rates and yields and their value is eroded by more inflation."[88] As such, when long-term Treasury yields increase faster than short-term yields (*i.e.*, the yield curve steepens), it is an indication that investors

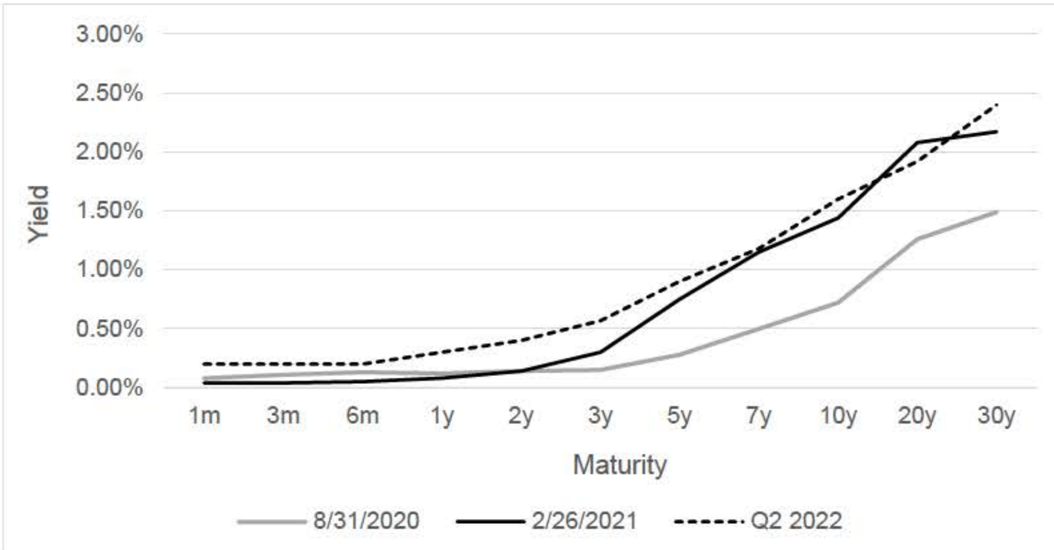
[86] Source: Bloomberg Professional Service; Nelson Direct Exhibit 5.

[87] *See, Blue Chip Financial Forecasts*, Vol. 39 No. 12, December 1, 2020, at 14.

[88] Alexandra Scaggs, *The Yield Curve is the Steepest It Has Been in Years. Here's What That Means for Investors*., *Barron's*, February 4, 2021.

expect stronger economic growth and inflation.[89] As Chart 11 shows, the yield curve has steepened since August 2020, and is expected to widen further by the second quarter of 2022.

Chart 11: Treasury Yield Curve[90]



Q. HAS THE FEDERAL RESERVE CHANGED ITS INFLATION POLICY RECENTLY?

A. Yes, it has. On August 27, 2020, Federal Reserve Chair Jerome H. Powell released a statement noting that Federal Open Market Committee will take an approach towards inflation that "could be viewed as a flexible form of average inflation targeting", meaning that following periods in which inflation has run

---

[89] Alexandra Scaggs, *The Yield Curve is the Steepest It Has Been in Years. Here's What That Means for Investors.*, *Barron's*, February 4, 2021.

[90] Source: Federal Reserve Board of Governors H.15 interest rate data. Q2 2022 projections from *Blue Chip Financial Forecasts*, Vol. 40, No. 3, March 1, 2021, at 2. Three-year, seven-year, and 20-year projected yields are interpolated.

below 2.00 percent, "appropriate monetary policy will likely aim to achieve inflation moderately above 2 percent for some time."[91]

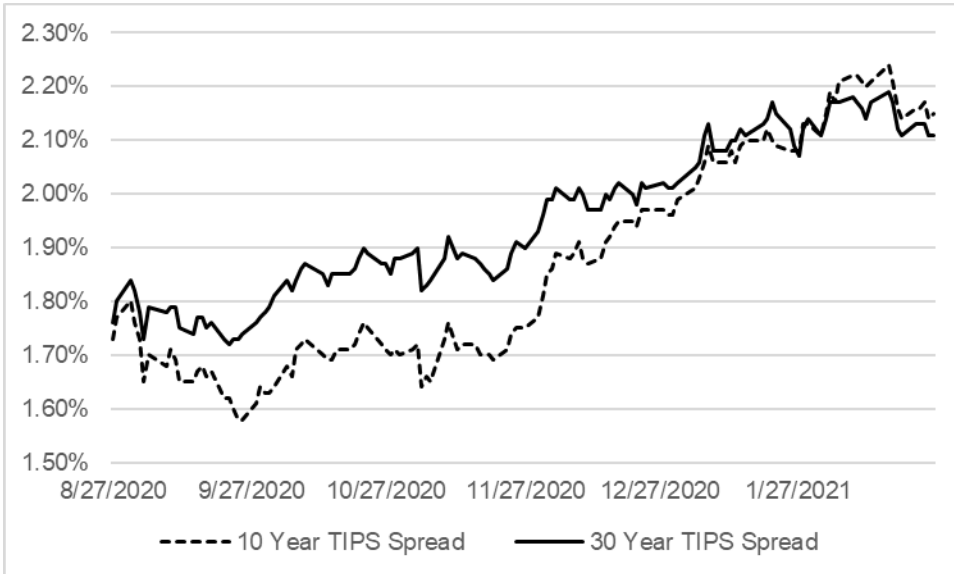
Since Chairman Powell's remarks, the breakeven inflation rate of ten-year and thirty-year Treasury securities,[92] represented as the spread between constant maturity Treasury Securities and Treasury Inflation-Protected Securities ("TIPS"), has increased from 1.73 percent and 1.76 percent, respectively, to 2.15 percent and 2.11 percent respectively, as of February 26, 2021. Further, as shown in Chart 12 below, breakeven inflation has trended upward since the Federal Reserve's target inflation policy change at a relatively consistent pace.

---

[91] *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.

[92] The 10-year breakeven inflation rate represents a measure of expected inflation derived from 10-Year Treasury Constant Maturity Securities and 10-Year Treasury Inflation-Indexed Constant Maturity Securities. The latest value implies what market participants expect inflation to be in the next 10 years, on average. The 30-year breakeven inflation rate represents a measure of expected inflation derived from 30-Year Treasury Constant Maturity Securities and 30-Year Treasury Inflation-Indexed Constant Maturity Securities. The latest value implies what market participants expect inflation to be in the next 30 years, on average. Source: Federal Reserve Bank of St. Louis FRED Economic Data.

Chart 12: Breakeven Inflation Rate[93]



Given these market-based indications of higher inflation expectations in the future, it is reasonable to expect long-term Treasury yields to also increase.

Q. WHAT CONCLUSIONS DO YOU DRAW FROM YOUR REVIEW OF THE CURRENT CAPITAL MARKET ENVIRONMENT AND ITS IMPLICATIONS ON THE COMPANY'S COST OF EQUITY?

A. In short, during a period of heightened and possibly prolonged market uncertainty, observable market information makes clear that utility investors now face greater risks, and therefore, require higher returns. When markets become uncertain and disrupted, investors increase their return requirements. Estimating that additional return requirement becomes increasingly complex. However, when utility investors are faced with such extraordinary market uncertainty, regulatory supportiveness becomes even more critically important.

[93] Source: Federal Reserve Board of Governors H.15 interest rate data.

I appreciate that the Commission has the difficult task of balancing the interests of customers and investors. I also appreciate that doing so becomes increasingly difficult under stressed economic and financial conditions. However, we should not lose sight of the common interest customers and investors have in a financially strong utility. On balance, I conclude the Company's Cost of Equity falls in the range of 9.60 percent to 10.75 percent. Although the uncertainty surrounding the eventual scope and duration of the current market dislocation supports an ROE toward the upper end of my recommended range; an ROE of 10.25 percent is a reasonable, if not conservative, estimate of the Company's Cost of Equity that balances the common interests of utility customers and investors.

VII. CAPITAL STRUCTURE

Q. WHAT IS THE COMPANY'S REQUESTED CAPITAL STRUCTURE?

A. As described by Company witness Phibbs, the Company requests a capital structure consisting of 54.88 percent common equity, 1.33 percent short-term debt, and 43.79 percent long-term debt.

Q. IS THERE A GENERALLY ACCEPTED APPROACH TO ASSESSING THE CAPITAL STRUCTURE FOR A REGULATED NATURAL GAS UTILITY?

A. Yes, there is. In general, it is important to consider the capital structure in light of industry norms and investor requirements. That is, the capital structure should be reasonably consistent with industry practice and enable the subject company to maintain its financial integrity, thereby enabling access to capital at competitive rates under a variety of economic and financial market conditions.

Q. HOW DOES THE CAPITAL STRUCTURE AFFECT THE COST OF CAPITAL?

A. It is well understood that from a financial perspective, there are two general categories of risk: business risk and financial risk. Business risk includes operating, market, regulatory, and competitive uncertainties, while financial risk is the incremental risk to investors associated with additional levels of debt. As such, the capital structure relates to a company's financial risk, which represents the risk that a company may not have adequate cash flows to meet its financial obligations, and is a function of the percentage of debt (or financial leverage) in its capital structure. In that regard, as the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt. Consequently, as the degree of financial leverage increases, the risk of financial distress (*i.e.*, financial risk) also increases.[94] In essence, even if two firms face the same business risks, a company with meaningfully higher levels of debt in its capital structure is likely to have a higher cost of both debt and equity. Since the capital structure can affect the subject company's overall level of risk, it is an important consideration in establishing a just and reasonable rate of return.

---

[94] *See,* Roger A. Morin, Ph.D., New Regulatory Finance, Public Utility Reports, Inc., 2006, at 45-46.

Q. IS THERE SUPPORT FOR THE PROPOSITION THAT THE CAPITAL STRUCTURE IS A KEY CONSIDERATION IN ESTABLISHING AN APPROPRIATE ROE?

A. Yes. The Supreme Court and various utilities commissions have long recognized the role of capital structure in the development of a just and reasonable rate of return for a regulated utility. In particular, a utility's leverage, or debt ratio, has been explicitly recognized as an important element in determining a just and reasonable rate of return:

> Although the determination of whether bonds or stocks should be issued is for management, the matter of debt ratio is not exclusively within its province. Debt ratio substantially affects the manner and cost of obtaining new capital. It is therefore an important factor in the rate of return and must necessarily be considered by and come within the authority of the body charged by law with the duty of fixing a just and reasonable rate of return.[95]

Perhaps ultimate authority for balancing the issues of cost and financial integrity is found in the Supreme Court's statement in *Hope*:

> 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.[96]

As the U.S. Court of Appeals, District of Columbia Circuit found in *Communications Satellite Corp. et. al. v. FCC*:

---

[95] *New England Telephone & Telegraph Co. v. State*, 98 N.H. 211, 97 A.2d 213, (1953), citing *New England Tel. & Tel. Co. v. Department of Pub. Util*., (Mass.) 327 Mass. 81, 97 N.E. 2d 509, 514; *Petitions of New England Tel. & Tel. Co*. 116 Vt. 480, 80 A2d 671, at 6.

[96] *Federal Power Commission v. Hope Natural Gas Co.,* 320 U.S., at 603 (1944).

> The equity investor's stake is made less secure as the company's debt rises, but the consumer rate-payer's burden is alleviated.[97]

Consequently, the principles of fairness and reasonableness with respect to the allowed rate of return and capital structure are considered at both the federal and state levels.

Q. PLEASE SUMMARIZE YOUR ANALYSIS OF THE PROXY COMPANIES' CAPITAL STRUCTURES.

A. First, it is important to keep in mind that the proxy group has been selected to reflect comparable companies in terms of financial and business risk. As such, it is appropriate to review the proxy companies' capital structures as a means of assessing whether the requested capital structure is consistent with industry practice. To the extent that the Company's requested capital structure differs from industry practice, the difference in financial risk should be considered when estimating its required Cost of Equity.

To make that assessment, I calculated the average equity ratio for each of the proxy group operating companies over the last eight quarters (*see* Nelson Direct Exhibit 8). The mean and median equity ratio of the proxy group is 52.90 percent and 55.26 percent, respectively.[98] The Company's requested equity ratio of 54.88 percent is within that range and falls below the average equity ratio of four of the seven proxy companies.

---

[97] *Communications Satellite Corp. et. al. v. FCC*, 198 U.S. App. D.C. 60, 63-64611 F.2d 883.

[98] Source: S&P Global Market Intelligence. As shown in Nelson Direct Exhibit 8, I have included short-term debt in my proxy group capital structure analysis.

Q. WHAT IS THE BASIS FOR USING AVERAGE CAPITAL COMPONENTS RATHER THAN A POINT-IN-TIME MEASUREMENT?

A. Measuring the capital components at a particular point in time can skew the capital structure by the specific circumstances of a particular period. Therefore, it is appropriate to normalize the relative relationship between the capital components over a period of time.

Q WHAT IS YOUR CONCLUSION REGARDING THE COMPANY'S REQUESTED CAPITAL STRUCTURE?

A. The requested common equity ratio of 54.88 percent is consistent with the equity ratios in place at the proxy group companies. As such, I conclude that a capital structure including 54.88 percent common equity, 1.33 percent short-term debt, and 43.79 percent long-term debt is reasonable and should be approved.

VIII. CONCLUSIONS

Q. WHAT IS YOUR CONCLUSION REGARDING THE ROE AND CAPITAL STRUCTURE FOR PSNC?

A. As discussed throughout my testimony, it is important to consider a variety of quantitative and qualitative information in reviewing analytical results and arriving at ROE determinations. Based on my review of the results from three commonly used analytical approaches, I conclude an ROE in the range of 9.60 percent to 10.75 percent represents the range of equity investors' required ROE for investment in natural gas utilities similar to PSNC. Within that range, I conclude that an ROE of 10.25 percent represents the Cost of Equity for PSNC.

That conclusion also considers PSNC's small size relative to the proxy companies, the Commission's recent ROE decisions, and the current capital market environment and economic conditions in North Carolina.

As to the capital structure, a capital structure including 54.88 percent common equity, 1.33 percent short-term debt, and 43.79 percent long-term debt is consistent with capital structures in place at the proxy companies. Therefore, I conclude it is reasonable and should be approved.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

REBUTTAL TESTIMONY

OF

JENNIFER E. NELSON

OCTOBER 7, 2021

TABLE OF CONTENTS

I. WITNESS IDENTIFICATION, PURPOSE, AND SUMMARY

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

A. My name is Jennifer E. Nelson. I am an Assistant Vice President at Concentric Energy Advisors. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS TESTIMONY?

A. I am submitting this rebuttal testimony ("Rebuttal Testimony") before the North Carolina Utilities Commission ("Commission") on behalf of Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or the "Company").

Q. ARE YOU THE SAME JENNIFER E. NELSON WHO FILED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my Rebuttal Testimony is to respond to the testimonies of John R. Hinton, on behalf of the Public Staff – North Carolina Utilities Commission ("Public Staff") and Kevin W. O'Donnell, on behalf of the Carolina Utility Customers Association ("CUCA", collectively, the "Opposing Witnesses"), as their testimonies relate to the appropriate Return on Equity ("ROE") and capital structure for PSNC. I also respond to Brian C. Collins, who testifies on behalf of Evergreen Packaging, LLC ("Evergreen") and expresses a brief opinion regarding the Company's requested ROE. Mr. Collins does not provide an independent analysis regarding the Company's Cost of Equity; instead, he recommends the Commission authorize an ROE no higher than the average authorized ROE for natural gas utilities over the twelve months ended June 30, 2021 (*i.e.*, 9.55 percent).[1] Because his recommendation is not based on an independent analysis relative to a group of risk-comparable proxy companies, the majority of my testimony responds to Mr. Hinton and Mr. O'Donnell. Please note that my silence in response on a particular issue should not be regarded as agreement with that issue.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS REGARDING THE APPROPRIATE ROE AND CAPITAL STRUCTURE FOR PSNC.

A. In my direct testimony, I concluded that an ROE in the range of 9.60 percent to 10.75 percent represents the range of equity investors' required return for investment in a natural gas utility such as PSNC. Within that range, I recommended the Commission authorize an ROE of 10.25 percent.[2] As to the capital structure, I concluded that the Company's requested capital structure consisting of 54.88 percent common equity, 1.33 percent short-term debt, and 43.79 percent long-term debt is consistent with the proxy group and is therefore reasonable. In its supplemental filing on August 10, 2021, the Company slightly modified its proposed capital structure to consist of 54.86 percent

[1] Direct Testimony of Brian C. Collins, at 16.
[2] Direct Testimony of Jennifer E. Nelson, at 3.

common equity, 1.34 percent short-term debt, and 43.80 percent long-term debt, which is also reasonable and should be approved. As discussed throughout my Rebuttal Testimony, my recommended ROE and conclusions regarding the reasonableness of the Company's proposed capital structure continue to hold based on my updated model results applying data as of August 31, 2021, and additional analyses provided in response to the Opposing Witnesses. As such, I maintain my recommendation regarding the ROE and support the updated capital structure.

Q. PLEASE SUMMARIZE YOUR RESPONSE TO THE OPPOSING WITNESSES REGARDING THE ROE AND CAPITAL STRUCTURE.

A. Quite simply, the Opposing Witnesses' analytical results and recommendations (as summarized in Table 1 below) are below any reasonable measure of PSNC's Cost of Equity and would likely be insufficient to maintain PSNC's credit rating. Overall, it is my opinion that if adopted, the Opposing Witnesses' recommendations would increase the Company's regulatory and financial risk, diminish its ability to compete for capital, and have the counter-productive effect of increasing its overall Cost of Capital, ultimately to the detriment of customers.

Table 1: Summary of ROE Ranges and Recommendations

	PSNC Witness Nelson (Direct)	PSNC Witness Nelson (Rebuttal)	Public Staff Witness Hinton[3]	CUCA Witness O'Donnell[4]	Evergreen Witness Collins
DCF Results	9.47% - 11.14%	8.44% - 12.18%	9.15% - 9.84%	7.50% - 9.50%	-
CAPM Results	12.48%- 13.34%	13.08%- 14.26%	-	6.00% - 8.00%	-
Risk Premium Results	9.75% - 9.86%	9.76% - 9.85%	9.49%	-	-
Comparable Earnings Results	-	-	9.50% - 10.00%	9.00% - 10.00%	-
ROE Recommendation (Range)	**10.25% (9.60% - 10.75%)**	**10.25% (9.60% - 10.75%)**	**9.48% (9.15% - 10.00%)**	**9.00% (6.00% - 10.00%)**	**≤ 9.55%**

Q. WHAT ARE THE KEY ISSUES IN WHICH YOU DISAGREE WITH THE OPPOSING WITNESSES' METHODS AND CONCLUSIONS REGARDING THE COMPANY'S COST OF EQUITY AND CAPITAL STRUCTURE?

A. Although there are several areas in which I disagree with the Opposing Witnesses' methods and conclusions, the key issues are:

- *The sufficiency of the Opposing Witnesses' recommendations to maintain PSNC's credit profile and credit ratings*. The Opposing Witnesses' recommendations to reduce both the authorized ROE and equity ratio would put further downward pressure on the Company's credit metrics that are already

[3] Hinton Exhibit 10.
[4] Direct Testimony of Kevin W. O'Donnell, at 80.

constrained, jeopardizing the Company's credit rating and investors' perceptions of the regulatory environment in North Carolina to the detriment of customers. As explained in the Rebuttal Testimony of Michael B. Phibbs, Moody's has clearly stated in published reports that the Company would be at risk of a downgrade if the Cash Flow from Operations (pre-working capital)/Debt ("CFO pre-WC/Debt") financial metric remains below 15.00 percent, which it has been for the past three years. Moody's also stated that PSNC's "Stable" outlook depends on a constructive outcome in this proceeding that materially improves its CFO pre-WC to Debt ratio from approximately a 12.00 percent range to a 15-17 percent range.

- *Flawed application of their ROE analytical models*. Consistent with investor and regulatory practice, the use of multiple generally accepted common equity cost rate models adds reliability and accuracy when arriving at a recommended common equity cost rate. While the Opposing Witnesses perform multiple Cost of Equity analyses, certain of their inputs and assumptions bias their results downward. Despite the fact that the Cost of Equity is forward-looking, the Opposing Witnesses give undue weight to historical-based inputs in many of their analyses. For example, Mr. Hinton does not consider forward-looking projected bond yields in his Risk Premium analysis and Mr. O'Donnell's CAPM-based estimates are based on the long-term average historical market risk premia that do not reasonably reflect current or expected market conditions. As a result, Mr. O'Donnell's Capital Asset Pricing Model ("CAPM")-based

ROE estimates are unreasonably low. Additionally, the Opposing Witnesses exclude or largely dismiss forward-looking expected returns on book equity in their Comparable Earnings Analysis. Lastly, Mr. O'Donnell includes negative growth rates in his Discounted Cash Flow ("DCF")-based results, violating common sense financial principles. Correcting for the flaws in the Opposing Witnesses' analyses produces more reasonable ROE estimates.

- *Improper imputation of a hypothetical capital structure*. The Opposing Witnesses each recommend the Commission impute a hypothetical capital structure (a 50.90 percent common equity ratio by Mr. Hinton and a 50.00 percent common equity ratio by Mr. O'Donnell). Mr. Hinton's and Mr. O'Donnell's hypothetical capital structure recommendations are not based on PSNC's specific risks and financing requirements, contrary to utility financing practices. Their recommendations presume that utilities should be financed with the same proportions of equity and debt as an "average" utility, notwithstanding the fact that it is common for utility capital structures to vary widely. Simply, neither Mr. Hinton nor Mr. O'Donnell has demonstrated that the Company's requested actual capital structure deviates substantially from sound utility practice.

Q. MR. HINTON REFERS TO MOODY'S RECENT CREDIT OPINIONS FOR THE COMPANY TO SUPPORT HIS CAPITAL STRUCTURE RECOMMENDATION.[5] DO YOU AGREE WITH HIS CONCLUSIONS?

A. No. Mr. Hinton's review is oversimplified and incomplete. Even though the Company's current authorized 52.00 percent equity ratio has not been sufficient to produce credit metrics within Moody's Baa1-rating thresholds as Mr. Phibbs explains, Mr. Hinton recommends the Commission further reduce PSNC's authorized equity ratio by 110 basis points. Specifically, Mr. Hinton's position overlooks the following conclusions from Moody's (emphasis added):

- "*PSNC's credit is constrained by the likelihood that weakened financial metrics will remain lower for longer* due to 1) increased leverage that has helped fund the utility's capital program, 2) a base rate freeze through November 2021, and 3) the negative cash flow impacts of federal tax reform, once new rates are set in place for 2022." (Hinton Exhibit 3, pages 1, 9).
- "PSNC's stable outlook reflects our expectation that its CFO pre-WC to debt ratio will improve to 15-17% beginning in 2022, following a general rate case filing and *what we expect to be supportive regulatory treatment from the North Carolina Utilities Commission* (NCUC)." (Hinton Exhibit 3, page 10).

[5] Direct Testimony of John R. Hinton, at 20-21.

- "Factors that could lead to a downgrade: *If the North Carolina regulatory environment were to become less credit supportive*" and "*CFO pre-WC to debt metric remains below 15%*." (Hinton Exhibit 3, page 10).
- "*PSNC's financials are positioned weakly* versus select A3 and Baa1 LDC Peers." (Hinton Exhibit 3, page 4).
- "However, the revenue increase associated with the investment recovery will be tempered by cash flow reductions that are commensurate with the December 2017 Tax Cuts and Jobs Act (*i.e.,* loss of bonus depreciation for utilities, federal tax rate reduction to 21% from 35% and the cash return of excess deferred income taxes over a period of time). This will likely keep CFO pre-WC to debt below 18%, *even when assuming a supportive general rate case outcome*." (Hinton Exhibit 3, page 12).

It is clear that Moody's "Stable" outlook and projected credit metrics for the Company depends on a constructive outcome in this proceeding. Instead, Mr. Hinton's (and Mr. O'Donnell's) recommendation to reduce both PSNC's authorized ROE and equity ratio is contrary to Moody's expectations and would further constrain the Company's financial profile, adversely affecting investors' perceptions of the regulatory environment in North Carolina.

Q. MR. O'DONNELL AND MR. COLLINS REFERENCE AUTHORIZED ROES FOR NATURAL GAS UTILITIES IN OTHER JURISDICTIONS.[6] DO YOU AGREE WITH THEIR CHARACTERIZATION OF THE TREND IN

[6] Direct Testimony of Kevin W. O'Donnell, at 66-67; Direct Testimony of Brian C. Collins, at 16.

AUTHORIZED ROES AND THE RELEVANCE OF THE TREND ON PSNC'S COST OF EQUITY?

A. No, I do not. National average returns must be placed in the proper context in order to be useful. While I agree that investors consider authorized returns in other states when assessing the reasonableness of the authorized ROE for PSNC, I have several concerns with the nationwide average ROE information presented by Mr. O'Donnell and Mr. Collins. First, annual average 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. Nonetheless, as Mr. O'Donnell's Chart 5 shows, the average authorized ROE for natural gas utilities has been relatively stable since 2013.[7] As shown in Chart 1 (below), there has been no discernible downward trend in authorized ROEs over the last five years. As such, I disagree with Mr. O'Donnell's characterization of a downward trend.

Second, market conditions at the time the authorized returns were established may be very different than conditions going forward. For example, equity returns set when interest rates were very low in 2020 are not a reasonable basis of comparison for evaluating the authorized ROE when bond yields have increased and are projected to continue increasing as the economy recovers and the Federal Reserve moves to a more neutral monetary policy.

[7] Direct Testimony of Kevin W. O'Donnell, at 67.

Q. ARE THE OPPOSING WITNESSES' RECOMMENDATIONS CONSISTENT WITH THOSE RECENTLY AUTHORIZED FOR NATURAL GAS UTILITIES ELSEWHERE IN THE U.S.?

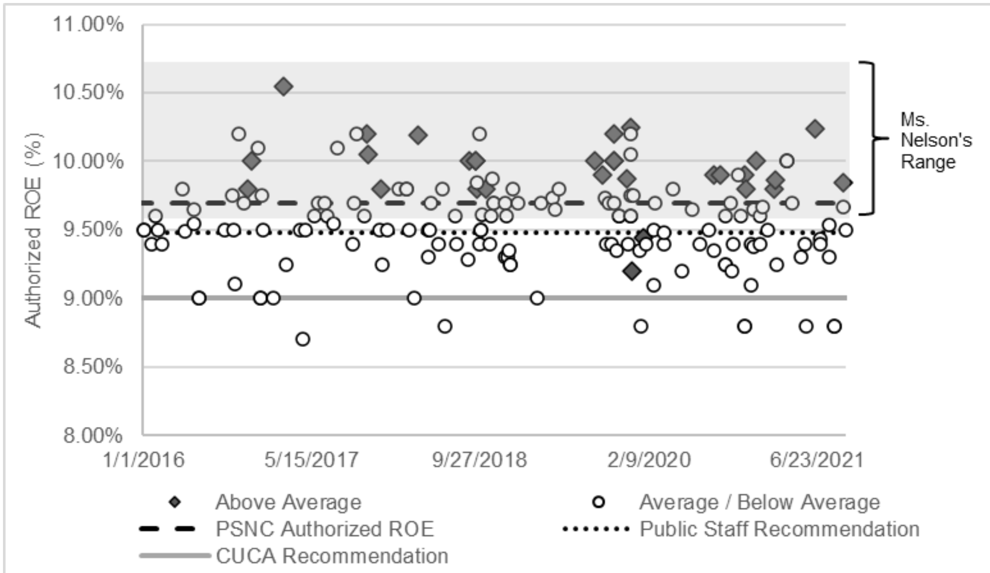
A. No, they are not. Mr. O'Donnell's 9.00 percent ROE recommendation falls in the bottom 5th percentile of ROEs authorized for natural gas utilities between 2016 and 2021. In other words, 95.00 percent of ROEs authorized for natural gas utilities over the last five years were above Mr. O'Donnell's 9.00 percent recommendation. Mr. Hinton's 9.48 percent ROE recommendation falls in the bottom 34th percentile of ROEs authorized for natural gas utilities over the last five years (*i.e.*, 66.00 percent were above his recommendation).

The Opposing Witnesses' recommendations are even more unduly low relative to ROEs authorized in jurisdictions that are ranked Average/1 and higher by Regulatory Research Associates ("RRA") in terms of regulatory constructiveness.[8] RRA ranks the Commission as Average/1 and jurisdictions ranked Average/1 and higher represent the top third of regulatory jurisdictions. Utilities with a similar ranking should generally have similar regulatory risk, making it reasonable to compare the returns available to utilities in jurisdictions that are viewed as similar to North Carolina. As Chart 1 below shows, my

[8] 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.

recommended ROE range is consistent with ROEs authorized in jurisdictions that are rated the same as, or better, than North Carolina in terms of regulatory constructiveness, whereas the Opposing Witnesses' recommendations are not.

Chart 1: Authorized ROE (2016 – 2021) and Witness Recommendations[9]



The difference in returns available to natural gas utilities in more constructive jurisdictions and those authorized in less constructive jurisdictions is unmistakable. Over the last five years, the average and median authorized ROE in jurisdictions ranked in the top third (*i.e.*, Average/1 and higher) was 9.94 percent and 9.95 percent, respectively. In jurisdictions ranked Average/2 and lower, the average and median authorized ROE was 9.52 percent and 9.50 percent, respectively.

---

[9] Source: Regulatory Research Associates. Authorized ROEs for natural gas utilities from January 1, 2016 through September 30, 2021. Excludes ROEs authorized in limited issue rate rider proceedings.

Q. WHAT ARE THE PRACTICAL IMPLICATIONS FOR PSNC OF A RETURN THAT IS FAR BELOW THOSE AUTHORIZED FOR OTHER UTILITIES?

A. The significant difference between the Opposing Witnesses' ROE and capital structure recommendations and those available to other utilities raises very practical concerns. First, PSNC must compete with other companies, including utilities, for the long-term capital needed to provide utility service. Given the choice between two similarly situated utilities, one with a return that falls far below industry levels, and another whose authorized return more closely aligns with those available to other utilities, investors will choose the latter.

In the end, the outcome of this proceeding will have important implications on the Company's ability to maintain its financial profile. I recognize the Commission must balance the interests of customers and shareholders; however, it is important to remember that PSNC's ability to access capital at reasonable terms to fund the investments necessary to provide safe, reliable service depends on a strong financial profile. From that perspective, customers benefit from a financially healthy utility and their interests are aligned.

Q. HOW IS THE REMAINDER OF YOUR REBUTTAL TESTIMONY ORGANIZED?

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

- Section II – Responds to the Opposing Witnesses' capital structure recommendations;
- Section III – Responds to the Opposing Witnesses' interpretation of the capital market environment;
- Section IV – Discusses the differences in the proxy groups used in our respective ROE analyses;
- Section V – Responds to the Opposing Witnesses regarding the ROE analytical approaches;
- Section VI – Updates my analyses of the economic conditions in North Carolina;
- Section VII – Presents the results of my updated ROE analyses; and
- Section VIII – Summarizes my conclusions and recommendations.

II. CAPITAL STRUCTURE

Q. PLEASE SUMMARIZE THE OPPOSING WITNESSES' RECOMMENDATIONS REGARDING THE APPROPRIATE CAPITAL STRUCTURE FOR PSNC.

A. Both Mr. Hinton and Mr. O'Donnell recommend the Commission authorize hypothetical capital structures that contain significantly less common equity than the Company's requested and current authorized capital structure (54.86 percent and 52.00 percent common equity, respectively), as summarized in Table 2 below. Mr. Collins does not provide a recommendation with respect to the Company's capital structure.

Table 2: Opposing Witnesses' Capital Structure Recommendations[10]

Witness (Party)	Common Equity	Long-Term Debt	Short-Term Debt
Mr. Hinton (Public Staff)	50.90%	47.71%	1.39%
Mr. O'Donnell (CUCA)	50.00%	48.53%	1.47%

Mr. Hinton's recommended hypothetical equity ratio of 50.90 percent is based on the average capital structures authorized for natural gas Local Distribution Companies ("LDC") in general rate cases during 2020 and 2021.[11] Mr. O'Donnell's recommended hypothetical equity ratio of 50.00 percent is based on his review of (1) the actual and projected equity ratios at his proxy group consolidated holding company level, (2) the actual and projected equity ratio for PSNC's parent Dominion Energy Inc. ("Dominion Energy"), and (3) average authorized equity ratios by state utility regulatory commissions from 2006-2020.[12]

Q. DO YOU AGREE WITH MR. HINTON'S AND MR. O'DONNELL'S HYPOTHETICAL CAPITAL STRUCTURE RECOMMENDATIONS?

A. No, I do not. Importantly, as noted earlier and as Company witness Phibbs explains, Mr. Hinton's and Mr. O'Donnell's hypothetical capital structure recommendations are likely insufficient to support PSNC's current credit rating. As Moody's notes, and as Mr. Phibbs explains, the Company's current 52.00 percent authorized equity ratio has not produced CFO pre-WC/Debt

[10] Direct Testimony of John R. Hinton, at 5; Direct Testimony of Kevin W. O'Donnell, at 5.
[11] Direct Testimony of John R. Hinton, at 23.
[12] Direct Testimony of Kevin W. O'Donnell, at 40-41, Table 5.

ratios above the 15.00 percent threshold necessary to sustain a Baa1 rating in the last three years. It therefore is unreasonable to expect that an authorized equity ratio of approximately 50.00 percent to 51.00 percent would somehow be sufficient, particularly when combined with a materially lower authorized ROE as the Opposing Witnesses recommend. Moody's credit opinion quite clearly emphasized that its rating and stable outlook for PSNC is based on its expectation of a constructive outcome in this proceeding that materially improves its CFO pre-WC to Debt ratio. The Opposing Witnesses' recommendations to reduce PSNC's authorized ROE and equity ratio would do the opposite, putting further downward pressure on the CFO pre-WC to Debt ratio (all else equal), jeopardizing the Company's credit rating and investors' perceptions of the regulatory environment in North Carolina.

Furthermore, Mr. Hinton's and Mr. O'Donnell's hypothetical capital structure recommendations are not based on PSNC's specific risks and financing requirements, contrary to utility financing practices. Their recommendations presume that utilities should be financed with the same proportions of equity and debt as an "average" utility, and that a utility with an equity ratio above the average suggests an "unbalanced" capital structure to the detriment of customers.[13] However, as explained below, utility capital structures vary widely based on the unique needs of each company. While I agree that reviewing the actual and authorized capital structures in place at other

[13] Direct Testimony of Kevin W. O'Donnell, at 32.

natural gas utilities provides insight into the reasonableness of a utility's capital structure, and may be used as a benchmark, in my opinion it is inappropriate to impute a hypothetical capital structure for ratemaking purposes based solely on industry averages unless it is clearly demonstrated that the requested actual capital structure deviates substantially from sound utility practice.[14] As discussed below, neither Mr. Hinton nor Mr. O'Donnell has satisfied that burden.

As shown in Nelson Direct Exhibit 8 and Nelson Rebuttal Exhibit 8, the Company's actual equity ratio of 54.86 percent is well within the range of the capital structures in place at the proxy companies. Moreover, although I disagree with certain of their capital structure analyses (as explained below), Mr. Hinton and Mr. O'Donnell's data demonstrates that PSNC's actual capital structure does not deviate substantially from sound utility practice. As shown in Mr. O'Donnell's Table 4, the Company's actual equity ratio of 54.86 percent is well within the range of his proxy group consolidated holding company historical and projected capital structures (ranging from 32.90 percent to 62.30 percent). Hinton Exhibit 5 also shows that the range of authorized equity ratios in 2020 and 2021 is between 46.26 percent and 60.12 percent. Here again, 54.86 percent is well within the range of recent authorized equity ratios for natural gas distribution utilities. There simply is no basis to conclude that the

[14] An example would be if an operating subsidiary was financed with 100 percent equity. *See also*, David C. Parcell, The Cost of Capital – A Practitioner's Guide, at 47 (2020 Edition).

Company's actual equity ratio of 54.86 percent deviates substantially from sound utility practice. As such, the Commission should reject Mr. Hinton's and Mr. O'Donnell's recommendations to impute a hypothetical capital structure for ratemaking purposes.

Q. PLEASE EXPLAIN THE FACTORS UTILITIES GENERALLY CONSIDER IN DEVELOPING THEIR CAPITAL STRUCTURES AND WHY IT IS IMPORTANT TO REFLECT UTILITY-SPECIFIC FINANCING REQUIREMENTS WHEN DETERMINING THE APPROPRIATE RATEMAKING CAPITAL STRUCTURE.

A. Companies (including subsidiary companies) are financed in light of the specific risks and funding requirements associated with their individual operations. Therefore, capital structures vary widely, even among utility companies. Capital structure management is dynamic and complex, looking to satisfy multiple objectives subject to multiple constraints. Utilities must focus on the nature of the assets providing utility service, and recognize the constraints brought about by the obligation to serve. It therefore is important to understand utility financing practice, including the principles and constraints that drive financing decisions, and how that practice is reflected in the Cost of Capital.

In many ways, the nature of regulation enables utilities to finance large, essentially irreversible, investments that are recovered over decades. In exchange for the obligation to serve, equity investors expect utilities to have the opportunity to earn a fair return on prudent investments over the life of the investments. Financing practices therefore must address the nature of investments made under the regulatory compact.

It also is important to keep in mind that capital structures, and the financial strength they support, are set not only to ensure capital access during normal markets, but when markets are constrained as well. The reason is straightforward: The obligation to serve is not contingent on capital market conditions. When markets are constrained, only those utilities with sufficient financial strength are able to attract capital at reasonable terms, which benefits customers. That ability provides those utilities with critically important financing flexibility. Relying more heavily on debt, as Mr. Hinton and Mr. O'Donnell propose, increases the risk of refinancing maturing obligations during less accommodating market environments at likely higher costs.

The requirement to access the capital markets in all market conditions can be contrasted with the financial needs of other entities without the legal obligation to serve. Because of that obligation, the financial flexibility brought about by the access to both long-term capital and short-term liquidity is critical for utilities' financial integrity, and their ability to continually attract capital. Unregulated firms have options to choose whether, where, and when to make investments; what services or products will be offered; whether to invest in expansions; and whether to cease operations in a given location. That is, unregulated companies may adjust the timing and amount of their major capital expenditures to align with economic cycles, and to defer decisions and investments to better match market conditions. Regulated companies have limited options to do so. Ensuring the financial strength to access capital because of the reduced spending flexibility therefore is critically important not only to utilities and shareholders, but to customers as well.

As noted above, an appropriate capital structure is important not only to ensure long-term financial integrity, it also is critical to enabling access to capital during constrained markets, or when near-term liquidity is needed to fund extraordinary requirements. In that important respect, the capital structure, and the financial strength it engenders, must support both normal circumstances and periods of market uncertainty. Although Mr. Hinton and Mr. O'Donnell suggest otherwise, optimizing the capital structure is a very complex process, which balances the need to maintain an appropriate financial profile while ensuring reasonable capital cost rates. Therefore, I disagree with their conclusion that a capital structure that contains more than 50 percent common equity, or contains more equity than industry averages, is by definition "unbalanced."

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S ANALYSIS REGARDING THE CAPITAL STRUCTURES IN PLACE FOR THE PROXY GROUP AT THE CONSOLIDATED HOLDING COMPANY LEVEL AS A

MEASURE OF THE APPROPRIATE RATEMAKING CAPITAL STRUCTURE FOR PSNC?

A. As Mr. Hinton and Mr. O'Donnell acknowledge,[15] because capital at the consolidated holding company level may finance unregulated operations, comparisons to the parent company capital structure may lead to flawed and misleading conclusions.

My capital structure analysis presented in Nelson Direct Exhibit 8 (and updated in Nelson Rebuttal Exhibit 8), however, calculates the capital structures in place for the proxy companies' *regulated* utility operations; therefore, it provides an apples-to-apples assessment of the reasonableness of PSNC's requested capital structure. As shown in Nelson Direct Exhibit 8, the Company's requested equity ratio of 54.86 percent is within the range of the proxy group's regulated equity ratio, demonstrating PSNC's financial risk is consistent with the proxy group. My updated analysis presented in Nelson Rebuttal Exhibit 8 continues to support the reasonableness of PSNC's requested capital structure. As such, PSNC's requested capital structure is consistent with the regulated capital structures in place at the proxy group.

Q. MR. HINTON ASSERTS YOUR PROXY GROUP CAPITAL STRUCTURE ANALYSIS IS "MISLEADING" BECAUSE IT INCLUDES "NON-REGULATED OPERATIONS AND OTHER CONCERNS THAT ARE NOT

[15] Direct Testimony of John R. Hinton, at 23; Direct Testimony of Kevin W. O'Donnell, at 41.

NECESSARILY APPROPRIATE FOR REGULATED UTILITIES."[16] WHAT IS YOUR RESPONSE?

A. Mr. Hinton's concern is misplaced. I understand Mr. Hinton's concern to be that capital structure data reported to the SEC may reflect capital that finances non-regulated operations in the proxy group. His concern would be valid if I used capital structure data for the consolidated holding company as Mr. O'Donnell does. However, my analysis presents quarterly capital structure data at the regulated operating company level for each of the utility operating subsidiaries in which data is reported. For example, in Nelson Rebuttal Exhibit 8, the capital structure data for South Jersey Industries in the top table reflects the capital structure only for South Jersey Gas Company as shown in the bottom table. Two companies, Atmos Energy Corporation and One Gas, Inc. are 100 percent regulated, so these companies' capital balances reflect only regulated operations. In other words, I have not used the consolidated holding company capital structure data in my analysis as Mr. O'Donnell has.

However, to respond to Mr. Hinton's concern, I prepared another capital structure analysis for the Combined Proxy Group using data reported on FERC Form 2 filed annually with the public utility commissions, which would reflect only regulated operations. I note FERC Form 2 data is reported annually, not quarterly, so I reviewed data as of the end of each year in 2018-2020.[17] The

---

[16] Direct Testimony of John R. Hinton, at 23.
[17] I note Spire Inc.'s fiscal year ends September 30, whereas the data reported for the other proxy companies use December 31.

results of that analysis are shown in Nelson Rebuttal Exhibit 9 and summarized in Table 3 below. As Table 3 shows, the Company's requested 54.86 percent equity ratio is highly consistent with the actual capital structures in place at the regulated operating companies within the Combined Proxy Group. As such, Mr. Hinton's concern is without merit.

Table 3: Combined Proxy Group Regulated Equity Ratio Reported on FERC Form 2, 2018-2020[18]

Company	2020	2019	2018	2018-2020 Average
ATO	58.31%	57.85%	58.35%	58.17%
CPK	NA	NA	NA	NA
MDU	48.89%	48.03%	71.31%	56.08%
NFG	58.99%	60.72%	58.39%	59.37%
NJR	55.13%	57.55%	58.86%	57.18%
NI	54.43%	54.33%	54.83%	54.53%
NWN	41.92%	45.77%	42.93%	43.54%
OGS	60.04%	63.28%	62.03%	61.78%
SJI	53.66%	54.52%	57.62%	55.26%
SWX	47.10%	46.35%	47.39%	46.94%
SR	52.90%	53.20%	54.54%	53.55%
UGI	47.44%	49.07%	47.63%	48.05%
MEAN	52.62%	53.70%	55.81%	54.04%
MEDIAN	53.66%	54.33%	57.62%	55.26%
HIGH	60.04%	63.28%	71.31%	61.78%
LOW	41.92%	45.77%	42.93%	43.54%

Q. MR. HINTON AND MR. O'DONNELL COMPARE PSNC'S REQUESTED EQUITY RATIO TO THE NATIONAL AVERAGE AUTHORIZED EQUITY

[18] Sources: FERC Form 2 reported to public utility commissions in the annual LDC reports. *See* Nelson Rebuttal Exhibit 9. The regulated operating subsidiaries of Chesapeake Utilities Corp. are financed with 100 percent equity and therefore have been excluded from the analysis.

RATIOS FOR NATURAL GAS UTILITIES.[19] PLEASE COMMENT ON THAT COMPARISON.

A. As explained previously, the Company's proposed equity ratio is well within the range of their data. In addition, the range of authorized equity ratios since 2019 has been between 46.26 percent to 60.18 percent.[20] PSNC's proposed equity ratio of 54.86 percent is well within this range.

For another perspective, I also looked to the capital structures authorized in jurisdictions ranked by RRA as Average/1 (the Commission's ranking from RRA) and higher since 2019. As shown in Table 4 below, the Company's requested equity ratio is within the range of those authorized in jurisdictions that are rated equal to or better than the Commission in terms of regulatory constructiveness.

Table 4: Authorized Equity Ratios for Natural Gas Utilities in Jurisdictions Ranked Average/1 and Higher (2019-2021)[21]

	Authorized Equity %
Average	52.60%
Median	52.02%
High	59.64%
Low	48.00%

Lastly, I reviewed the current authorized equity ratios of the Combined Proxy Group companies. Several proxy companies operate under a Formula

[19] Direct Testimony of John R. Hinton, at 23 and Hinton Exhibit 5; Direct Testimony of Kevin W. O'Donnell, at 38, 40.
[20] Source: Regulatory Research Associates, excluding decisions in Arkansas, Florida, Indiana, and Michigan that include non-investor supplied capital.
[21] Source: Regulatory Research Associates. Distribution rate cases completed through September 30, 2021, excluding decisions in Arkansas, Florida, Indiana, and Michigan that include non-investor supplied capital.

Rate Plan ("FRP") framework in one or more jurisdictions (*i.e.*, Atmos Energy Corp., ONE Gas, Inc., and Spire Energy). FRPs allow for streamlined annual rate reviews that adjust rates annually if earnings are outside a specified target ROE bandwidth. Utilities that operate under an FRP have less frequent general rate cases where the ROE and capital structure are determined; therefore, depending on the timeframe under review, those companies' authorized capital structures would not appear in the RRA rate case data set used by me and the Opposing Witnesses.[22] As such, the current authorized return provides relevant data points as to the returns available to the companies that Mr. Hinton and Mr. O'Donnell agree are comparable in risk to PSNC.

As shown in Table 5 below, PSNC's 54.86 percent requested equity ratio is consistent with the current authorized equity ratio for the Combined Proxy Group.

[22] For example, Spire Inc. has not had a general rate case since 1981 for Spire Alabama and 1995 for Spire Gulf, Inc.

Table 5: Combined Proxy Group Current Authorized Equity Ratio[23]

Company	Average Current Authorized Equity Ratio
ATO	57.89%
CPK	57.41%
MDU	50.38%
NFG	42.90%
NI	49.61%
NJR	54.00%
NWN	49.50%
OGS	59.75%
SJI	52.75%
SWX	50.94%
SR	53.79%
UGI	NA
Average	52.63%
Median	52.75%
High	59.75%
Low	42.90%

Q. DO YOU HAVE ANY OTHER OBSERVATIONS REGARDING MR. O'DONNELL'S ANALYSIS OF NATIONAL AVERAGE AUTHORIZED EQUITY RATIOS FOR NATURAL GAS UTILITIES?[24]

A. Yes, I do. Mr. O'Donnell's Chart 4 shows a clear upward trend in the average authorized equity ratio in the last 15 years. Particularly important is the increase since 2017, partly in recognition of the need to somewhat mitigate the effects

[23] Sources: Regulatory Research Associates; individual company 2020 10-Ks. None of UGI's operating companies published an equity ratio as part of its most recent rate cases. Represents the straight average current authorized equity ratio in each jurisdiction for each proxy company.

[24] Direct Testimony of Kevin W. O'Donnell, at 38-40.

of the Tax Cuts and Jobs Act ("TCJA") on utilities' cash flows and their credit profiles.[25]

Q. HAVE ANY CREDIT RATING AGENCIES COMMENTED ON THE EFFECT OF THE TCJA ON PSNC'S CREDIT PROFILE?

A. Yes. In its January 2020 Credit Opinion for PSNC, Moody's noted that the Company's credit is "constrained by the likelihood that weakened financial metrics will remain lower for longer" due in part to increased leverage (*i.e.*, more debt in the capital structure) and negative cash flow impacts of federal tax reform.[26] Moody's went on to note that any revenue increase associated with the outcome of this proceeding will be "tempered by cash flow reductions that are commensurate with the December 2017 Tax Cuts and Jobs Act"[27] Moody's reiterated these concerns in its February 2021 Credit Opinion update.[28]

Q. MR. O'DONNELL SUGGESTS THAT THE COMPANY IS ENGAGING IN DOUBLE LEVERAGE TO THE DETRIMENT OF CUSTOMERS.[29] WHAT IS YOUR RESPONSE?

A. Mr. O'Donnell's position violates widely accepted regulatory and financial principles and should be dismissed. Turning first to the regulatory principles,

[25] *See, e.g.,* Georgia Public Service Commission, Docket No. 42516, Short Order Adopting Settlement Agreement as Modified, at 7 (December 31, 2019). The ROE and capital structure were not resolved in the Settlement Agreement and therefore were determined by the Georgia PSC. The Georgia PSC determined a 56.00 percent capital structure was reasonable and appropriate, finding a "56% common equity level is just and reasonable considering all the evidence presented and is necessary to avoid a credit rating downgrade."
[26] Hinton Exhibit 3, at 1.
[27] Hinton Exhibit 3, at 3.
[28] Hinton Exhibit 3, at 9, 12.
[29] Direct Testimony of Kevin W. O'Donnell, at 39-40.

under the standalone principle of ratemaking, as explained in my direct testimony, each utility subsidiary is treated as its own company.[30] At issue in this proceeding is the appropriate Cost of Capital for PSNC, not Dominion Energy. Under the standalone principle, the Cost of Capital is based on the subsidiary's capital structure and costs of debt and equity. The Cost of Equity is estimated based on a determination of the subject company's standalone risk profile by reference to a proxy group of firms of comparable risk.

With respect to financial principles, a widely accepted financial principle is that the Cost of Capital is based on the use of funds, not on the source of funds. In other words, a company's ownership structure or source of capital does not affect its Cost of Capital. From an external investor's perspective, the consolidated parent company must provide a return reflecting the risks of the company's constituent parts. As such, investors value the consolidated entity on a "sum-of-the-parts" basis, expecting each operating segment to provide its appropriate risk-adjusted return, which is consistent with the standalone regulatory principle explained above. In other words, under both financial and regulatory principles, it is the subsidiary utility's operating risk (*i.e.*, the use of funds) that defines the capital structure and Cost of Capital, not the parent company or source of funds. The double leverage argument, however, would require every affiliate within the corporate family to have the

---

[30] Direct Testimony of Jennifer E. Nelson, at 48.

same Cost of Capital, regardless of differences in risk. As Dr. Roger Morin notes in his text New Regulatory Finance:

> Just as individual investors require different returns from different assets in managing their personal affairs, why should regulation cause parent companies making investment decisions on behalf of their shareholders to act any differently? A parent company normally invests money in many operating companies of varying sizes and varying risks. These operating subsidiaries pay different rates for the use of investor capital, such as long-term debt capital, because investors recognize the differences in capital structure, risk, and prospects between the subsidiaries. Yet, the double leverage calculation would assign the same return to each activity, based on the parent's cost of capital. Investors recognize that different subsidiaries are exposed to different risks, as evidenced by the different bond ratings and cost rates of operating subsidiaries. The same argument carries over to common equity. If the cost rate for debt is different because the risk is different, the cost rate for common equity is also different, and the double leverage adjustment shouldn't obscure this fact.[31]

Several financial texts support these principles. For example, in Principles of Corporate Finance, Brealey, Myers, and Allen state:

> In principle, each project should be evaluated at its own opportunity cost of capital; the true cost of capital depends on the use to which the capital is put. If we wish to estimate the cost of capital for a particular project, it is project risk that counts.[32]

Mr. O'Donnell's double leverage argument violates another financial principle: the "law of one price," which states that in an efficient market, identical assets would have the same value. As Dr. Roger Morin notes:

> Carrying the double leverage standard to its logical conclusion leads to even more unreasonable prescriptions. If the common shares of a subsidiary were held by both the parent and by

[31] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., at 524-525 (2006).
[32] Richard A. Brealey, Stewart C. Myers, Franklin Allen, Principles of Corporate Finance, McGraw-Hill Irwin, 8th Ed., 2006, at 234.

> individual investors, the equity contributed by the parent would have one cost under the double leverage computation, while the equity contributed by the public would have another.[33]

In an efficient market, identical assets have the same price, or value. If they don't, the difference can be arbitraged away.

Lastly, several regulatory commissions have rejected double leverage arguments. For example, the Maryland Public Service Commission has stated:

> We reject People's Counsel's proposed capital structure [reflecting a double leverage adjustment] because it suffers from numerous flaws. First, it assumes that the rate of return depends on the source of capital rather than the risks faced by the capital.[34]

The FERC also reiterated its position on double leverage stating in a 2016 order that "the motivations of a parent company are irrelevant"[35] so long as the operating company passes the FERC's three-part test: (1) it issues its own debt without guarantees; (2) it has its own bond rating; and (3) it has a capital structure within the range of capital structures approved by the FERC.[36]

Q. MR. O'DONNELL SUGGESTS THAT PSNC'S "RELATIVELY HIGHER EQUITY PERCENTAGE WILL TRANSLATE INTO HIGHER COSTS TO

---

[33] Roger A. Morin, New Regulatory Finance, Public Utility Reports, Inc., at 523 (2006).

[34] Maryland Public Service Commission, Order No. 81517, Case No. 9092, In the Matter of the Application of Potomac Electric Power Company for Authority to Revise its Rate and Charges for Electric Service and for Certain Rate Design Changes, July 19, 2007, at 73. [Clarification added]

[35] *See*, 154 FERC ¶ 61,004, Docket No. ER15-945-001, at 15.

[36] *Ibid*. See also, Transcontinental Gas Pipe Line Corp., 80 FERC ¶ 61,157, Opinion No. 414 (1997).

PSNC'S CUSTOMERS WITHOUT ANY CORRESPONDING IMPROVEMENT IN QUALITY OF SERVICE."[37] DO YOU AGREE?

A. No, I do not. Mr. O'Donnell's position presumes that customers do not benefit from a capital structure that contains more than 50.00 percent equity simply because the cost of equity is greater than the cost of debt. However, a utility with a capital structure that consists of less debt has less financial risk, and therefore lower costs of both debt and equity, all else equal. Moreover, as explained in my direct testimony, an overall rate of return that is adequate to attract capital at reasonable terms when and as needed enables the utility to make the necessary investments to provide safe, reliable natural gas service while maintaining its financial integrity. In that respect, customers benefit, and their interests are aligned with shareholders' interests.

Q. IS THERE A RECENT EXAMPLE THAT DEMONSTRATES THE IMPORTANCE OF MAINTAINING A STRONG FINANCIAL PROFILE TO CUSTOMERS' BENEFIT?

A. Yes, there is. In February of 2021, Winter Storm Uri hit Texas and the midwestern U.S., knocking out electric power to millions of customers and constraining natural gas supplies, which pushed customer demand and natural gas commodity costs to record highs. In such situations, natural gas utilities cannot delay or defer purchasing natural gas, as customers rely on natural gas to heat their homes. Consequently, as Moody's noted, the surge in natural gas

[37] Direct Testimony of Kevin W. O'Donnell, at 30.

commodity costs "strained liquidity for utilities in Texas, Oklahoma, Kansas, and neighboring states."[38] Two of the proxy companies, Atmos Energy Corporation and ONE Gas, Inc., each reported more than $2 billion in natural gas commodity costs attributed to the storm.[39] However, each were able to issue more than $2 billion in long-term debt at low costs[40] which may not have been possible but for their A-rated credit ratings,[41] strong balance sheets, and expectation for constructive regulatory treatment in recovering the natural gas commodity costs.[42] In this situation, Atmos Energy Corporation's and ONE Gas's customers benefited from these companies' strong balance sheets, each of which had approximately 58 percent to 60 percent equity in their regulated operating company capital structures as of December 31, 2020 (*see* Nelson Rebuttal Exhibit 9).

Adverse events can happen unpredictably (*see, e.g.*, Winter Storm Uri and COVID-19), and it is important that utilities maintain a strong financial profile that enables them to access capital when and as needed in all market environments.

---

[38] S&P Capital IQ Pro, "Gas utilities 'most severely affected' by winter storm prices, Moody's says," March 8, 2021.
[39] S&P Capital IQ Pro, "Gas utilities 'most severely affected' by winter storm prices, Moody's says," March 8, 2021.
[40] S&P Capital IQ Pro, "Atmos Energy completes senior notes offering," March 9, 2021; "One Gas to pay $2.2B for gas purchases, secures $2.5B term loan facility," February 22, 2021.
[41] Nonetheless, both companies were downgraded. S&P downgraded Atmos Energy Corporation from A to A- on February 22, 2021. S&P downgraded ONE Gas Inc. two notches from A to BBB+ on February 23, 2021.
[42] *See, e.g.*, S&P Capital IQ Pro, "Gas utilities face multibillion-dollar financing needs after storm price surge," February 22, 2021.

Q. WHAT IS YOUR CONCLUSION WITH REGARD TO PSNC'S PROPOSED CAPITAL STRUCTURE?

A. PSNC'S requested capital structure reflects its specific financing requirements and risk profile and is reasonable compared to the range of equity ratios for the regulated operating companies held by the proxy group as well as to authorized equity ratios for natural gas utilities in other jurisdictions. Neither Mr. Hinton nor Mr. O'Donnell have demonstrated that PSNC's actual capital structure deviates substantially from sound utility practice. Moody's has clearly expressed that a constructive outcome in this proceeding will enable PSNC to maintain its current credit rating. Lastly, PSNC's proposed capital structure enables it to maintain its financial strength, which translates into favorable access to capital for the benefit of customers. For these reasons, the proposed capital structure for PSNC is appropriate and should be approved by the Commission.

III. CAPITAL MARKET ENVIRONMENT

Q. PLEASE SUMMARIZE THE OPPOSING WITNESSES' REVIEW OF THE CURRENT CAPITAL MARKET ENVIRONMENT.

A. Mr. Hinton reviews A-rated utility bond yields since 2016, concluding they have declined, and along with them, so has the Cost of Capital.[43] Mr. Hinton

[43] Direct Testimony of John R. Hinton, at 12.

also notes that observed inflation rates have increased, but questions whether the increases in inflation are transitory or temporary.[44]

Mr. O'Donnell reviews changes in the 30-year Treasury yield since 2016, closing stock prices of the Dow Jones Utility Average and Dow Jones Industrial Average, and statements by the Federal Reserve during this summer.[45]

Q. THE OPPOSING WITNESSES APPEAR TO DOWNPLAY THE INFLATION RISK IN FINANCIAL MARKETS.[46] WHAT IS YOUR RESPONSE?

A. The expectation for rising inflation that was discussed in my direct testimony in April 2021 has persisted as evidenced by the U.S. Bureau of Labor Statistics' announcement on September 14, 2021, that the Consumer Price Index for All Urban Consumers increased at a 5.30 percent annual rate over the last 12 months.

While the U.S. Federal Reserve has commented that it views inflation risk as likely being short-term and transitory, the Federal Reserve summarized in its September 22, 2021 press release that "Overall financial conditions remain accommodative, in part reflecting policy measures to support the economy and the flow of credit to U.S. households and businesses." And "[t]he

[44] Direct Testimony of John R. Hinton, at 12-13.
[45] Direct Testimony of Kevin W. O'Donnell, at 7-19.
[46] Direct Testimony of John R. Hinton, at 12-13; Direct Testimony of Kevin W. O'Donnell, at 20-21.

path of the economy continues to depend on the course of the virus." In terms of its current posture, it indicated:

> The Committee seeks to achieve maximum employment and inflation at the rate of 2 percent over the longer run. With inflation having run persistently below this longer-run goal, the Committee will aim to achieve inflation moderately above 2 percent for some time so that inflation averages 2 percent over time and longer-term inflation expectations remain well anchored at 2 percent. The Committee expects to maintain an accommodative stance of monetary policy until these outcomes are achieved. The Committee decided to keep the target range for the federal funds rate at 0 to 1/4 percent and expects it will be appropriate to maintain this target range until labor market conditions have reached levels consistent with the Committee's assessments of maximum employment and inflation has risen to 2 percent and is on track to moderately exceed 2 percent for some time. Last December, the Committee indicated that it would continue to increase its holdings of Treasury securities by at least $80 billion per month and of agency mortgage-backed securities by at least $40 billion per month until substantial further progress has been made toward its maximum employment and price stability goals. Since then, the economy has made progress toward these goals. If progress continues broadly as expected, the Committee judges that a moderation in the pace of asset purchases may soon be warranted. These asset purchases help foster smooth market functioning and accommodative financial conditions, thereby supporting the flow of credit to households and businesses.[47]

The Federal Reserve's actions and statements are subject to interpretation, but it is clear that the Federal Reserve is signaling a less accommodative monetary policy and a willingness for inflation to exceed 2.00 percent in the near term. Following a recent sell-off in equity markets ("the sharpest pullback since May"), *The Wall Street Journal* summarized:

[47] Board of Governors of the Federal Reserve System, Press Release, September 22, 2021.

> Investors agree the economic outlook has improved significantly since 2020. But many wonder how well the market will be able to stand on its own once the Fed begins to taper its monthly asset purchases—especially since they credit much of the market's rebound from its pandemic low to extraordinary levels of monetary and fiscal support from Washington. Some investors have also expressed concerns about the economic outlook. Inflation has made a surprising comeback this year, something some worry will start to cut into companies' profit margins.[48]

With regard to whether inflation is short-term or transitory in nature, several investment advisory firms and economists have expressed the view that inflation will last longer than expected. For example, a June 25, 2021 Reuters article indicated that Bank of America expects U.S. inflation to remain elevated for an extended period:

> BofA expects U.S. inflation to remain elevated for two to four years, against a rising perception of it being transitory, and said that only a financial market crash would prevent central banks from tightening policy in the next six months. It was "fascinating so many deem inflation as transitory when stimulus, economic growth, asset/housing/commodity inflation are deemed permanent," the investment bank's top strategist Michael Hartnett said in a note on Friday. Hartnett thinks inflation will remain in the 2%-4% range over the next 2- 4 years. U.S. inflation has averaged 3% in the last 100 years, 2% in the 2010s, and 1% in 2020, but it has been annualizing at 8% so far in 2021, BofA said in the note.[49]

As shown in Chart 2 below (which updates Chart 12 in my direct testimony), the breakeven inflation rate of 10-year and 30-year Treasury

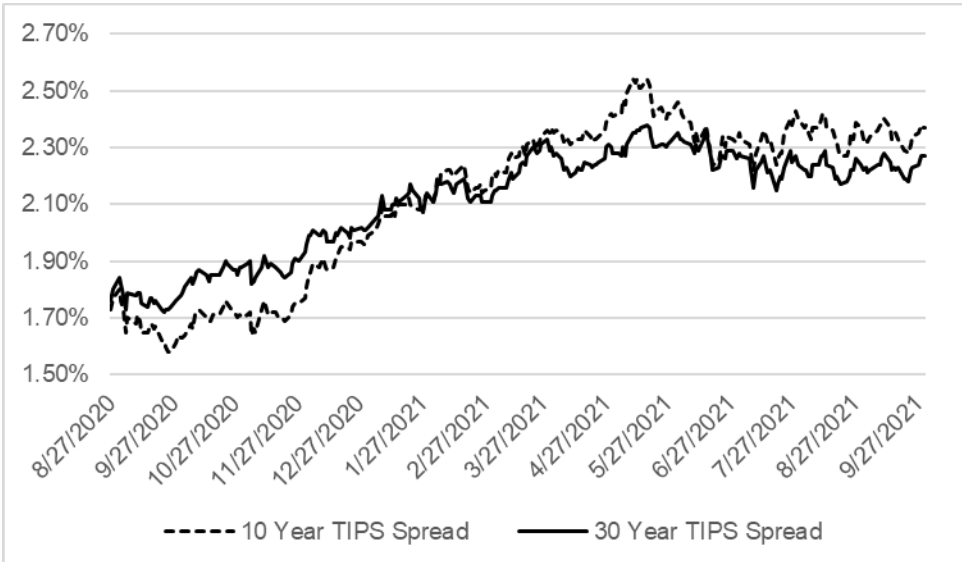
---

[48] "Stocks Close Sharply Lower as Bond Yields Hit Three-Month High," *The Wall Street Journal*, September 28, 2021.

[49] Reuters, U.S. Inflation likely to remain elevated for up to four years – BofA, at 2 (June 25, 2021).

securities[50] remains above the Federal Reserve's 2.00 percent inflation target and within a narrow range since I filed my direct testimony.

Chart 2: Breakeven Inflation Rate[51]



Given these market-based indications of higher inflation expectations in the future, it is reasonable to expect long-term Treasury yields to also increase, supporting the use of projected interest rates.

Q. MR. O'DONNELL REFERS TO SEVERAL RECENT REPORTS BY STANDARD & POOR'S ("S&P") CONCLUDING THAT THE CURRENT

[50] The 10-year breakeven inflation rate represents a measure of expected inflation derived from 10-Year Treasury Constant Maturity Securities and 10-Year Treasury Inflation-Indexed Constant Maturity Securities. The latest value implies what market participants expect inflation to be in the next 10 years, on average. The 30-year breakeven inflation rate represents a measure of expected inflation derived from 30-Year Treasury Constant Maturity Securities and 30-Year Treasury Inflation-Indexed Constant Maturity Securities. The latest value implies what market participants expect inflation to be in the next 30 years, on average. Source: Federal Reserve Bank of St. Louis FRED Economic Data.

[51] Source: Federal Reserve Board of Governors H.15 interest rates, as of September 30, 2021.

OUTLOOK FOR REGULATED UTILITIES IS STABLE.[52] DO YOU AGREE?

A. No, I do not. Mr. O'Donnell reviews certain recent articles from S&P to suggest that the outlook for regulated utilities is stable; however, he ignores a critical finding that the industry performed poorly from a credit quality perspective. In January 2021 S&P noted:

> 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 by about 7 to 1.[53]

Clearly, S&P's finding calls into question Mr. O'Donnell's view of the stability of the utility industry. As explained throughout my Rebuttal Testimony, the ability to maintain a strong credit profile is critical to utilities' ability to provide safe, reliable service to the benefit of customers. That holds true for PSNC as well.

Q. DO YOU AGREE WITH MR. O'DONNELL'S POSITION THAT UTILITIES ARE "A SAFE HARBOR" DURING PERIODS OF MARKET UNCERTAINTY?[54]

A. While Mr. O'Donnell's position may have been true during prior periods of market downturns, that has not been the case during the COVID-19 market dislocation. As explained in my direct testimony, both the utility sector and the

---

[52] Direct Testimony of Kevin W. O'Donnell, at 12-14.

[53] S&P Global Ratings, RatingsDirect, *North American Regulated Utilities' Negative Outlook Could See Modest Improvement*, January 20, 2021, at 2-3.

[54] Direct Testimony of Kevin W. O'Donnell, at 10.

S&P 500 lost approximately 34.00 percent of its value at the early part of the pandemic.[55] Additionally, the returns from the companies in my proxy group have been more volatile (*i.e.*, riskier) than the S&P 500. As shown in Chart 10 in my direct testimony, the proxy group's relative volatility ratio has been above 1.0 and has been increasing. As Chart 10 also demonstrates, the proxy group companies' returns have been more correlated with returns of the S&P 500 Index. That is, the proxy companies have been trading in a more similar pattern as the S&P 500 Index. Whereas Mr. O'Donnell's position may be based on past conventional wisdom, the data does not support his conclusion. Simply, utilities have been more volatile, and therefore riskier, than the broad market since at least February 2020. That data supports an increase in the Cost of Equity.

IV. PROXY GROUP

Q. DO MR. HINTON AND MR. O'DONNELL USE THE SAME PROXY GROUP AS YOU TO PERFORM THEIR ROE ANALYSES?

A. No. While all of the companies included in my proxy group are included in both Mr. Hinton's and Mr. O'Donnell's proxy groups, both witnesses include additional companies, as summarized in Table 6 below, presumably because they believe a proxy group of seven companies is too small. Mr. O'Donnell includes all ten companies *Value Line* classifies as natural gas utilities.[56] Mr.

[55] Direct Testimony of Jennifer E. Nelson, at 61.
[56] Direct Testimony of Kevin W. O'Donnell, at 25.

Hinton excludes NiSource, Inc., but includes MDU Resources and National Fuel Gas, which *Value Line* classifies as natural gas diversified companies, but also have natural gas distribution operations.[57]

Table 6: Comparison of Witness Proxy Group Companies

Company	Ticker	Ms. Nelson (PSNC)	Mr. Hinton (Public Staff)	Mr. O'Donnell (CUCA)
Atmos Energy Corporation	ATO	X	X	X
Chesapeake Utilities	CPK		X	X
MDU Resources	MDU		X	
National Fuel Gas	NFG		X	
New Jersey Resources Corp.	NJR	X	X	X
NiSource Inc.	NI			X
Northwest Natural Holding Co.	NWN	X	X	X
ONE Gas, Inc.	OGS	X	X	X
South Jersey Industries, Inc.	SJI	X	X	X
Southwest Gas Holdings, Inc.	SWX	X	X	X
Spire Inc.	SR	X	X	X
UGI Corporation	UGI		X	X

Q. IS A PROXY GROUP OF SEVEN COMPANIES TOO SMALL?

A. No. As explained in my direct testimony,[58] including companies whose fundamental comparability to the subject company is tenuous. Simply expanding the number of observations does not add relevant information to the analysis. Therefore, there is no reason to place more reliance on the range of results derived from a larger, but potentially less comparable proxy group simply by virtue of the larger number of observations.

[57] Direct Testimony of John R. Hinton, at 31-32.
[58] Direct Testimony of Jennifer E. Nelson, at 22.

Nonetheless, I have performed an additional set of DCF and CAPM analyses based on a proxy group of the 12 companies in Mr. Hinton's, Mr. O'Donnell's, and my proxy groups combined (the "Combined Proxy Group") using data as of August 31, 2021.[59] The DCF and CAPM results based on the Combined Proxy Group continue to support my recommended range of 9.60 percent to 10.75 percent with a point estimate of 10.25 percent (*see* Tables 11a and 11b in Section VII below).

V. RESPONSE TO OPPOSING WITNESSES REGARDING THE ROE ANALYSES

Q. PLEASE SUMMARIZE THE OPPOSING WITNESSES' ROE ANALYSES AND HOW THEY DEVELOPED THEIR OVERALL ROE RECOMMENDATIONS.

A. Mr. Hinton's 9.48 percent ROE recommendation was developed by giving three-fourths weight to his three DCF-based ROE estimates and one-fourth weight to his Risk Premium-based ROE estimate as shown in Table 7 below.

Table 7: Mr. Hinton's ROE Recommendation[60]

	ROE Estimate
DCF Method	
Historical Growth Rates	9.15%
Historical and Forecasted Growth Rates	9.44%
Forecasted Growth Rates	9.84%
Risk Premium Method	
LDC regression analysis	9.49%
Average	**9.48%**

[59] See Nelson Rebuttal Exhibits 3, 4, and 6.
[60] Hinton Exhibit 10.

Mr. Hinton also performs a Comparable Earnings Analysis (with proxy group average and median results of 10.00 percent and 9.50 percent, respectively), however he uses it only as a check on the reasonableness of his other model results.[61]

Mr. O'Donnell's 9.00 percent recommendation is based primarily on the results of his DCF analysis,[62] though he also performs a Comparable Earnings Analysis and a CAPM analysis.

Table 8: Mr. O'Donnell's ROE Recommendation[63]

	Low	High
DCF Method	7.50%	9.50%
Comparable Earnings Analysis	9.00%	10.00%
CAPM	6.00%	8.00%
Overall Recommended ROE	**9.00%**	

I respond to their applications of each of these models below. I also respond to their criticisms of my ROE analyses.

A. Discounted Cash Flow Analysis

Q. PLEASE SUMMARIZE MR. HINTON'S AND MR. O'DONNELL'S DCF ANALYSES AND RESULTS.

A. Mr. Hinton applies his DCF analysis to the 11 companies selected in his proxy group (*see* Table 6 above) to develop a DCF-based cost of common equity

[61] Direct Testimony of John R. Hinton, at 36-38.
[62] Direct Testimony of Kevin W. O'Donnell, at 47, 64-65.
[63] Direct Testimony of Kevin W. O'Donnell, at 80.

estimates ranging from of 9.15 percent to 9.84 percent.[64] He calculates the dividend yield for each proxy company by dividing *Value Line's* estimate of next year's dividend by the stock price reported in the *Value Line Summary & Index* report over the 13-weeks ended September 10, 2021.[65]

For the growth rate component, Mr. Hinton reviews the following historical and forecasted growth rates:

- Five- and ten-year historical Earnings Per Share ("EPS"), Dividend Per Share ("DPS") and Book Value Per Share ("BVPS") growth rates reported by *Value Line*;
- Five-year projected EPS, DPS, and BVPS growth rates from *Value Line*; and
- Projected EPS growth rates from Yahoo! Finance and CFRA.[66]

Mr. O'Donnell calculates his dividend yields in the same manner as Mr. Hinton, but also reviews four-week and one-week averages in addition to a 13-week average.[67] Mr. O'Donnell also reviews the same historical and projected growth rates from *Value Line* and projected EPS growth rates from CFRA. He also reviews the long-term EPS growth rate from Charles Schwab, and calculates a "plowback" growth rate for each of his proxy companies based on *Value Line* data.[68]

---

[64] Direct Testimony of John R. Hinton, at 34.
[65] Direct Testimony of John R. Hinton, at 32.
[66] Direct Testimony of John R. Hinton, at 33 and Hinton Exhibit 7.
[67] Direct Testimony of Kevin W. O'Donnell, at 52-53.
[68] Direct Testimony of Kevin W. O'Donnell, at 57-59.

Q. DO YOU HAVE ANY INITIAL OBSERVATIONS REGARDING THE OPPOSING WITNESSES' DCF ANALYSES?

A. Yes, I do. Turning first to Mr. O'Donnell's analysis, his DCF analysis includes negative growth rates, which is inconsistent with the model's underlying assumptions. No investor would invest in a stock with negative growth prospects in perpetuity. The inclusion of negative growth rates downwardly biases his growth rates, and therefore his DCF results, on which his 9.00 percent ROE recommendation primarily relies. If negative growth rates were excluded, Mr. O'Donnell's DCF results based on his historical and forecasted growth rates[69] for his proxy group would range from approximately 8.80 percent to 11.00 percent (*see* Table 9, below, and Nelson Rebuttal Exhibit 10). The average and maximum corrected DCF-based ROE estimates largely overlap with my recommended range.

Table 9: Mr. O'Donnell's Historical and Forecasted DCF Results Excluding Negative Growth Rates

Natural Gas DCF Results: Mr. O'Donnell's Proxy Group			
	Minimum	Average	Maximum
Value Line Historical Growth Rate Averages + *Value Line* Div Yield Range	8.8%	9.5%	9.9%
Forecasted Growth Rate Averages + *Value Line* Div Yield Range	8.4%	9.7%	11.0%

Turning to Mr. Hinton's DCF analysis, after reviewing Hinton Exhibit 7 in its native Excel format, I observe that his average DCF result from both

[69] As discussed below, his DCF-results based on his "plowback" ratio growth rates should not be given any weight. Because they are substantially below his 9.00 ROE recommendation, it appears he has given them limited weight as well.

historical and forecasted growth rates (*i.e.*, 9.44 percent) excluded his proxy group average DCF result from CFRA of 9.70 percent. As such, the corrected DCF result using historical and forecasted growth rates is 9.46 percent, which increases his overall ROE recommendation slightly to 9.49 percent (*see* Hinton Exhibit 10).

Q. THE OPPOSING WITNESSES CRITICIZE YOUR RELIANCE ON PROJECTED EARNINGS GROWTH RATES IN YOUR DCF ANALYSIS.[70] ARE HISTORICAL GROWTH RATES APPROPRIATE FOR USE IN THE DCF MODEL?

A. No, they are not. Mr. O'Donnell and Mr. Hinton assert I have "ignored" historical growth rates.[71] Mr. Hinton further points to prior Commission orders to criticize the reliance on projected growth rates.[72] I respectfully disagree with their positions.

As explained in my direct testimony[73] (and as Mr. Hinton acknowledges[74]), the Cost of Equity is forward-looking and the growth rate component is the long-term annual growth rate *expected* in perpetuity.[75] As such, investors' expected growth rates are the most appropriate for use in the DCF model. By applying historical growth rates as the expected growth component in the DCF model, Mr. Hinton and Mr. O'Donnell presume these

[70] Direct Testimony of Kevin W. O'Donnell, at 84; Direct Testimony of John R. Hinton, at 46-47.
[71] Direct Testimony of Kevin W. O'Donnell, at 84; Direct Testimony of John R. Hinton, at 46-47.
[72] Direct Testimony of John R. Hinton, at 47.
[73] Direct Testimony of Jennifer E. Nelson, at 70.
[74] Direct Testimony of John R. Hinton, at 28.
[75] Direct Testimony of Jennifer E. Nelson, at 24.

historical growth rates will persist in perpetuity. However, past performance is not necessarily an indicator of future expectations. Further, historical growth rates are likely factored into analysts' projections; therefore, placing any weight on historical growth rates gives undue weight to historical growth estimates. For example, Mr. Hinton develops Cost of Equity estimates using six historical growth rate measures, but only five projected growth rate measures. Moreover, the Opposing Witnesses' five-year historical growth rates are a subset of the ten-year historical growth rates and are therefore double counted.

Lastly, I note that in Docket No. G-9, Sub 743 for Piedmont Natural Gas ("Piedmont"), while the Commission noted its past findings regarding reliance on earnings growth rate projections, it found Piedmont's ROE witness Mr. Hevert's DCF results that relied on analysts' earnings growth rate projections to be "credible, probative, and entitled to substantial weight."[76] Contrary to Mr. O'Donnell's position,[77] the projected earnings growth rates I apply in my DCF analysis are consistent with Mr. Hinton's and Mr. O'Donnell's historical growth rates (excluding Mr. O'Donnell's negative growth rates).[78] Therefore,

---

[76] *In the Matter of Application of Piedmont Natural Gas Company, Inc., for an Adjustment of Rates, Charges, and Tariffs Applicable to Service in North Carolina, Continuation of its IMR Mechanism, Adoption of an EDIT Rider, and Other Relief*, NCUC Docket No. G-9, Sub 743, Order Approving Stipulation, Granting Partial Rate Increase, Line 434 Revenue Rider, EDIT Riders, Provisional Revenues Rider, and Requiring Customer Notice, at 41 (October 31, 2019).

[77] Direct Testimony of Kevin W. O'Donnell, at 87.

[78] In Nelson Direct Exhibit 2, the average and median of my proxy group DCF growth rates is 6.58 percent and 6.00 percent, respectively. Updated for more recent data in Nelson Rebuttal Exhibit 1, my proxy group average and median growth rates are 6.27 percent and 5.83 percent, respectively. Those growth rates are comparable to Mr. Hinton's proxy group average historical growth rates ranging from 4.80 percent to 6.60 percent, respectively (Hinton Exhibit 7), and Mr. O'Donnell's proxy group average historical growth rates ranging from 5.20 percent to 6.90 percent, excluding negative growth (Exhibit KWO-2, *see also* Nelson Rebuttal Exhibit 10).

projected EPS growth rates produce reasonable and reliable Cost of Equity estimates.

Q. THE OPPOSING WITNESSES POINT TO LITERATURE TO SUPPORT THEIR POSITION THAT ANALYSTS' EARNINGS FORECASTS ARE OVERSTATED.[79] WHAT IS YOUR RESPONSE?

A. None of the literature cited by Mr. Hinton or Mr. O'Donnell is specific to our proxy group companies or to the utility sector. As such, the Opposing Witnesses have not demonstrated that the issue applies to utility companies. As regulated companies, there is much more transparency into utility companies' operations and the factors that affect future earnings (such as capital expenditure plans and rate base growth) than there is for non-regulated firms. Accordingly, utility equity analysts have more information from which to develop their projections.

The 2003 study by Chan, *et. al* cited by both Mr. Hinton and Mr. O'Donnell was performed prior to the 2003 Global Analysts Research Settlement that required financial institutions to insulate investment banking from analysis, prohibited analysts from participating in "road shows," and required the settling financial institutions to fund independent third-party research.

A 2010 article in Financial Analysts Journal found that analyst forecast bias declined significantly or disappeared entirely after the Global Settlement:

[79] Direct Testimony of John R. Hinton, at 46; Direct Testimony of Kevin W. O'Donnell, at 85-86.

> Introduced in 2002, the Global Settlement and related regulations had an even bigger impact than Reg FD on analyst behavior. After the Global Settlement, the mean forecast bias declined significantly, whereas the median forecast bias essentially disappeared. Although disentangling the impact of the Global Settlement from that or related rules and regulations aimed at mitigating analysts' conflicts of interest is impossible, forecast bias clearly declined around the time the Global Settlement was announced. These results suggest that the recent efforts of regulators have helped neutralize analysts' conflicts of interest.[80]

In addition, analysts covering the common stock of the proxy companies certify that their analyses and recommendations are not related, either directly or indirectly, to their compensation.

Lastly, to the extent analysts' earnings growth rate projections are persistently overstated, as the Opposing Witnesses suggest, investors likely are aware and reflect this information in their stock buying decisions, which means that stock prices already reflect this information.

In the end, my projected earnings growth rates are consistent with Mr. Hinton and Mr. O'Donnell's historical growth rates. As such, there is no basis to conclude that the projected earnings growth rates applied in our DCF analyses, and the DCF-based ROE estimates that are based on them, are overstated.

[80] Armen Hovakimian and Ekkachai Saenyasiri, *Conflicts of Interest and Analyst Behavior: Evidence from Recent Changes in Regulation*, Financial Analysts Journal, Volume 66, Number 4, July/August 2010, at 105.

Q. ARE ANALYSTS' EARNINGS GROWTH PROJECTIONS CONSISTENT WITH THE MANAGEMENT GUIDANCE ISSUED RECENTLY IN THE PROXY COMPANIES' INVESTOR PRESENTATIONS?

A. Yes. I reviewed the long-term projected EPS growth rate guidance provided by the proxy companies' management teams in recent Investor Presentations to assess analysts' long-term EPS growth rate projections relative to management expectations. As shown in Table 10 below, of the proxy companies that provide EPS growth guidance, analysts' EPS growth rate projections are generally below (*i.e.*, more conservative) or within the range of managements' EPS growth guidance for all but one proxy company. Market analysts carefully monitor the accuracy of management forecasts and a "missed forecast" can lead to both a sell-off in the company's stock and a black mark on the management team's credibility with the market. These relationships reinforce discipline in developing management guidance.

Table 10: Analysts' Earnings Growth Rates vs. Management Guidance[81]

	As of 2/28/2021			As of 8/31/2021					
Ticker	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Value Line Earnings Growth	Yahoo! Finance Earnings Growth	Zacks Earnings Growth	Average EPS	Management Guidance EPS range	Analysts' range relative to EPS guidance
ATO	7.00%	7.10%	7.50%	7.00%	7.80%	7.40%	7%	6-8%	Within
CPK	8.50%	4.74%	NA	8.50%	4.74%	NA	7%	NA	NA
MDU	10.50%	NA	NA	10.50%	7.10%	6.90%	8%	5-8%	Within
NFG	19.00%	NA	NA	19.00%	8.50%	NA	9%	NA	NA
NJR	1.50%	6.00%	6.00%	2.00%	6.00%	7.10%	5%	6-10%	Below
NI	10.00%	4.37%	6.20%	9.50%	3.52%	6.20%	6%	7-9%	Below
NWN	5.50%	3.10%	NA	5.50%	5.50%	4.90%	5%	3-5%	Within
OGS	6.50%	5.00%	6.00%	6.50%	5.00%	5.00%	6%	5-7%	Within
SJI	10.50%	24.50%	24.50%	11.50%	4.80%	5.40%	7%	5-8%	Within
SWX	8.00%	4.00%	5.00%	8.00%	4.00%	5.50%	6%	NA	NA
SR	9.00%	5.70%	5.00%	10.00%	7.31%	5.50%	8%	5-7%	Above
UGI	5.50%	7.35%	8.00%	6.50%	7.75%	8.00%	7%	6-10%	Within

Q. DO YOU AGREE WITH THE OPPOSING WITNESSES' USE OF GROWTH RATES OTHER THAN EARNINGS GROWTH?

A. No, I do not. As explained in my direct testimony, and as Mr. O'Donnell acknowledges, over the long term, dividend growth can only be sustained by earnings growth.[82]

Importantly, when providing guidance to investors regarding the overall total return targets in their investor presentations, companies define the total return as the dividend yield plus *earnings* growth, not dividend growth.[83] Moreover, earnings growth projections are the only widely accepted and widely published estimates of growth, which demonstrates that earnings growth is the most meaningful measure of growth among the investment community. Academic studies suggest that investors base their investment decisions on

[81] Source: Investor Presentations released during August and September 2021.
[82] Direct testimony of Jennifer E. Nelson, at 25-26; Direct Testimony of Kevin W. O'Donnell, at 53-54.
[83] *See e.g.,* Dominion Energy Inc, May 5, 2021 Annual Meeting of Shareholders presentation, at 38.

analysts' expectations of growth in earnings.[84] I am not aware of any similar findings regarding dividend- or book value-based growth estimates. In addition, the only forward-looking growth rates that are available on a consensus basis are analysts' EPS growth rate projections. The fact that earnings growth projections are the only widely-accepted estimates of growth further supports the finding that earnings growth is the most meaningful measure of growth among the investment community.

Lastly, Mr. O'Donnell's sustainable growth rate (or "plowback ratio") calculations rely on *Value Line's* return on book equity data for the proxy group companies, which are the same estimates relied upon in his Comparable Earnings Analysis that he believes produces less reliable ROE results. Those projected ROEs are substantially higher than the results of the DCF model using sustainable growth rates presented by Mr. O'Donnell and demonstrate that investors expect to earn higher returns on equity from the proxy group companies than what is produced by the DCF model using sustainable growth rates. If Mr. O'Donnell believes his Comparable Earnings Analysis produces "inferior" results,[85] it is inconsistent and inappropriate to give weight to his "plowback ratio" growth estimates that rely on the primary input of his

[84] *See*, e.g., Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts Growth Forecasts,* Financial Management, Summer 1992, at 65; and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management, Spring 1988, at 81. Please note that while the original study was published in 1988, it was updated in 2004 under the direction of Dr. Vander Weide. The results of that updated study are consistent with Vander Weide and Carleton's original conclusions.

[85] Direct Testimony of Kevin W. O'Donnell, at 65.

Comparable Earnings-based results. Nonetheless, his DCF estimates based on his "plowback" ratio growth rates are substantially below his 9.00 percent ROE recommendation, so it appears Mr. O'Donnell has not given them much weight either.

Q. MR. HINTON CRITICIZES YOUR QUARTERLY GROWTH DCF ANALYSIS. WHAT IS YOUR RESPONSE?

A. Mr. Hinton's criticism appears to be that the Quarterly Growth DCF results are "above the required rate of return by investors".[86] In my opinion, his position is results-oriented and subjective based on his view of "the required rate of return by investors," which is an unobservable parameter. Mr. Hinton also points to Commission orders from 15 or more years ago to support his position that ratepayers should not "provide for that added or incremental return associated with the quarterly payment of dividends they receive."[87] As discussed below, I respectfully disagree with that conclusion.

As a preliminary matter, the objective of the ROE witnesses' testimony this proceeding is to estimate the Cost of Capital, which is an input into the Company's revenue requirement and reflects a cost to the Company. Because the Cost of Equity is unobservable, analysts must use multiple methodologies to develop the best estimate with the data that is available. Since utilities pay dividends on a quarterly basis, it is more accurate and consistent with the DCF

[86] Direct Testimony of John R. Hinton, at 48.
[87] Direct Testimony of John R. Hinton, at 48.

model's fundamental structure to use the quarterly DCF model to estimate the market-required Cost of Equity.[88] The stock prices paid by investors (an input in both the Constant Growth and Quarterly Growth DCF models) assume the quarterly timing of dividend payments; therefore, an accurate DCF-based Cost of Equity estimate must also reflect the actual timing of quarterly dividends.[89] As Dr. Roger Morin explains:

> "[T]he quarterly DCF model rests on the same assumptions as the annual DCF model except that the DCF model is refined to reflect the actual corporate practice of paying dividends quarterly rather than once per year."[90]

That is, the only difference between these two variations of the DCF model is the reflection of quarterly dividend payments.

As explained in my direct testimony, although the half-year dividend growth adjustment applied in the Constant Growth DCF analysis is meant to approximate the payment of quarterly dividends, it is a conservative, simplifying assumption that does not fully reflect the quarterly receipt and reinvestment of dividends.[91] As such, it underestimates the Cost of Equity for quarterly dividend paying companies such as utilities. In other words, the Quarterly Growth DCF model does not add an "incremental" cost to customers as Mr. Hinton suggests; it is a more precise estimate of the DCF-estimated Cost of Equity, as the Constant Growth DCF model understates the Cost of Equity.

[88] Direct Testimony of Jennifer E. Nelson, at 30-31.
[89] Roger A. Morin, Ph.D., New Regulatory Finance, Public Utility Reports, Inc., at 344 (2006).
[90] Roger A. Morin, Ph.D., New Regulatory Finance, Public Utility Reports, Inc., at 343 (2006).
[91] Direct Testimony of Jennifer E. Nelson, at 30.

Consequently, the Quarterly Growth DCF model provides an additional perspective into an otherwise unobservable parameter and should be given consideration.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE OPPOSING WITNESSES' DCF ANALYSES?

A. I conclude that the Opposing Witnesses' DCF analyses give undue weight to historical growth rates, which result in Cost of Equity estimates that understate the Company's Cost of Equity. Because the Opposing Witnesses give primary weight to their DCF results, their overall ROE recommendations are similarly biased downward. There is substantial academic and practical evidence that investors are concerned with expected growth in earnings, and as such, I recommend the Commission place more weight on DCF results based on projected earnings growth rates. Lastly, I believe the Quarterly Growth DCF model is reliable, credible, and should be given weight by the Commission.

B. Capital Asset Pricing Model and Empirical Capital Asset Pricing Model

Q. BEFORE RESPONDING TO THE OPPOSING WITNESSES' CRITICISMS OF YOUR CAPM ANALYSIS, ARE THERE AREAS OF AGREEMENT WITH RESPECT TO THE CAPM ANALYSIS?

A. Yes, there are. As a preliminary matter, Mr. Hinton did not perform a CAPM analysis to develop his Cost of Equity estimate; however, he critiques my application of the model, which I respond to below.

Mr. O'Donnell and I agree that the 30-year Treasury bond yield is appropriate to use as the risk-free rate.[92] Second, Mr. O'Donnell applies two estimates of the risk-free rate above the current rate of 1.91 percent, suggesting he believes that the current rate underestimates the expected risk-free rate.[93] Third, Mr. O'Donnell and I both rely on *Value Line* Beta coefficients.[94]

Q. WHAT IS YOUR REPONSE TO THE OPPOSING WITNESSES' CONCERN REGARDING THE FORWARD-LOOKING MARKET RISK PREMIUM YOU APPLY IN YOUR CAPM ANALYSIS?[95]

A. The use of a forward-looking or projected market risk premium is appropriate because the historical average market risk premium does not reflect the inverse relationship between interest rates and the market risk premium. The Ibbotson data that is used to calculate the historical market risk premium of approximately 7.20 percent indicates that the long-term average return on large company stocks from 1926-2020 was 12.20 percent, while the average income-only return on government bonds was 4.90 percent over the same period.[96] It is therefore not reasonable to use the historical market risk premium when the current 30-day average yield on the 30-year Treasury bond is 1.91 percent, or approximately 300 basis points *lower* than the bond yield used to calculate the

[92] Direct Testimony of Kevin W. O'Donnell, at 71.
[93] Direct Testimony of Kevin W. O'Donnell, at 71-73 and Exhibit KWO-7.
[94] Direct Testimony of Kevin W. O'Donnell, at 78.
[95] Direct Testimony of John R. Hinton, at 48-49; Direct Testimony of Kevin W. O'Donnell, at 89-91.
[96] Duff & Phelps, 2021 SBBI Yearbook, at 6-17.

historical market risk premium. With interest rates at these levels, the forward-looking market risk premium should be *higher* than 7.20 percent.

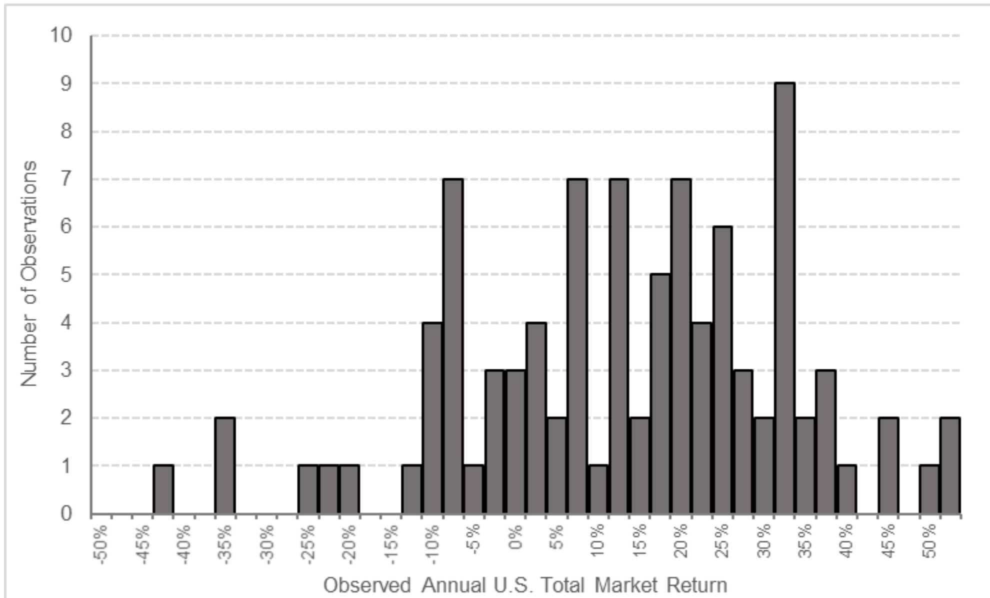
Second, the current low interest rate environment is due to economic weakness caused by the COVID-19 pandemic. The U.S. Congress has supported the economy by providing fiscal stimulus, and the Federal Reserve has reduced short-term interest rates and engaged in Quantitative Easing (*i.e.*, bond-buying, asset purchases, etc.), which has caused long-term interest rates to decline. Under these conditions, it is perfectly reasonable that projected growth rates for the S&P 500 companies would be higher than the historical average assuming that financial markets have confidence that the actions taken to stimulate the economy will be successful and lead to ongoing economic recovery, as Mr. O'Donnell appears to concede is occurring.[97]

Mr. O'Donnell observes that the geometric mean and arithmetic mean return on large company stocks from 1972 – 2019 is 10.7 percent and 12.1 percent, respectively,[98] asserting that the total market return used in my forward-looking market risk premium calculation is not reasonable on that basis. However, these averages obscure the wide variation in realized equity returns from year to year. To demonstrate, I analyzed the annual performance of the S&P 500 from 1926-2020. As shown in Chart 3 below, the actual return on the S&P 500 Index has exceeded 15.00 percent[99] in nearly half (47 out of 95

[97] Direct Testimony of Kevin W. O'Donnell, at 6.
[98] Direct Testimony of Kevin W. O'Donnell, at 74.
[99] The *Value Line*-based Market Return estimate in Nelson Direct Exhibit 4, page 7, is 14.34 percent; in Nelson Rebuttal Exhibit 5, page 1, the *Value Line*-based Market Return estimate is 15.05 percent.

years) of the time between 1926-2020. These data demonstrate that actual observed total returns for the broad market greater than 15.00 percent are not unrealistic, as Mr. Hinton and Mr. O'Donnell assert.

Chart 3: Total Returns of S&P 500 Index – 1926-2020[100]



I conclude that my projected market return estimates are reasonable and consistent with historically observed market returns. Therefore, applying forward-looking inputs for the risk-free rate and market risk premium, along with current Beta coefficients from *Value Line,* the CAPM produces results that should be considered along with the results from the DCF and Bond Yield Plus Risk Premium models.

[100] Source: Duff & Phelps, 2021 SBBI Yearbook, Appendix A-1.

Q. IS THE ACCURACY OF BOND YIELD OR INTEREST RATE FORECASTS RELEVANT IN ESTIMATING THE COST OF EQUITY AS MR. HINTON AND MR. O'DONNELL ASSERT?[101]

A. No, it is not. As the FERC has found, the Cost of Equity depends on what the market expects, not what ultimately happens.[102] Nonetheless, neither Mr. Hinton nor Mr. O'Donnell has demonstrated that current interest rates are any more accurate at predicting future interest rates.

Lastly, in deference to the Commission's preference, I have presented CAPM analyses using both current and projected bond yields in the CAPM model. I conclude that it is reasonable and appropriate to use the projected 30-year Treasury bond yield as the risk-free rate under current market conditions when interest rates are forecast to increase by approximately 112 basis points above current average yields on long-term government bonds.

Q. PLEASE SUMMARIZE MR. O'DONNELL'S APPLICATION OF THE CAPM.

A. Mr. O'Donnell applies a historical U.S. 30-year Treasury yield as his risk-free rate; *Value Line* Beta coefficients; and a market risk premium that is based on historical total returns for large company stocks and long-term government bonds, as well as certain investment professionals' forecasts for his market risk premium, to produce his CAPM-based ROE range of 6.00 percent to 8.00

[101] Direct Testimony of John R. Hinton, at 14-17; Direct Testimony of Kevin W. O'Donnell, at 71.
[102] *See*, 147 FERC ¶ 61,234, Docket No. EL11-66-001, Opinion No. 531 Order on Initial Decision, at para. 88 (June 19, 2014).

percent.[103] As a principal matter, ROE estimates of 8.00 percent and lower are far below any meaningful measure of the Company's Cost of Equity. As such, I agree with Mr. O'Donnell's decision to not rely on his CAPM results.

Q. WHAT IS YOUR CONCERN WITH MR. O'DONNELL'S APPLICATION OF THE CAPM?

A. Although I recognize Mr. O'Donnell has not relied substantially on his CAPM analysis in determining his ROE recommendation, my primary concern is with Mr. O'Donnell's market risk premium. He calculates the arithmetic and geometric average historical market risk premium as the difference between the total return on large company stocks and the total return on long-term government bonds as reported by Duff & Phelps (formerly Ibbotson) over his selected period of 1972 to 2020.[104] He also reviews surveys of certain investment bank forecasts. From these reviews, he concludes that the market risk premium ranges from 4.25 percent to 6.25 percent.[105]

Turning first to his review of historical risk premia, the use of a historical market risk premium is not appropriate under current market conditions because it does not reflect the inverse relationship between interest rates and the equity risk premium. When the current average yield on U.S. Treasury bonds is well below the long-term historical average yield, it is reasonable to expect that the market risk premium would be well above the

---

[103] Direct Testimony of Kevin W. O'Donnell, at 79.
[104] Direct Testimony of Kevin W. O'Donnell, at 74.
[105] Direct Testimony of Kevin W. O'Donnell, at 74-78.

historical average market risk premium. Consequently, the long-term average historical market risk premium would be appropriate only if the expected risk-free rate was consistent with the long-term historical risk-free rate, which it currently is not.

Furthermore, the long-term historical average market risk premium Mr. O'Donnell calculates is incorrect because he subtracts an average *total* return on long-term government bonds from an average total return on large capitalization stocks rather than the average *income* return on long-term government bonds. As noted in Duff & Phelps' 2021 SBBI Yearbook (emphasis added):

> 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.**[106]

[106] Duff & Phelps, 2021 SBBI Yearbook, at 10-22.

Lastly, Mr. O'Donnell's selected historical market return period is subjective in nature and unrepresentative of long-term trends in market data. As explained by Duff & Phelps:

> 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 influenced 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 series makes it less likely that the analyst can justify any number he or she wants.[107]

As noted earlier, however, because the current average yield on 30-year U.S. Treasury bonds (1.91 percent) is well below the long-term historical average return (4.90 percent), it is reasonable to expect the market risk premium to be well above the historical average market risk premium (7.20 percent).

Q. DO YOU AGREE WITH THE OPPOSING WITNESSES' REFERENCE TO SURVEYS OF EXPECTED RETURNS?[108]

A. No, I do not. As is the case with historical market risk premia, it is unclear whether market risk premium estimates that are based on expected market returns from surveys bear any relationship to the survey respondent's expectations regarding interest rates. Therefore, it is unclear whether market risk premium estimates calculated based on surveys reflect the inverse relationship between interest rates and the market risk premium.

---

[107] Duff & Phelps, 2021 SBBI Yearbook, at 10-23.
[108] Direct Testimony of John R. Hinton, at 49-50; Direct Testimony of Kevin W. O'Donnell, at 74-76.

Additionally, Mr. Hinton and Mr. O'Donnell point to surveys of *expected* returns, which are not the same as *required* returns. The task of estimating the cost of equity is to estimate the investors' *required* return, not investors' *expected* returns. Therefore, the Commission should not rely on surveys to measure the expected market return applied in the CAPM.

Lastly, although Mr. O'Donnell and Mr. Hinton are concerned about the accuracy of earnings growth rate and interest rate projections, they do not seem to be concerned with the accuracy of the surveys' estimates of market returns. As shown in Chart 3 above, the total return on large company stocks in the range of the surveys reviewed by the Opposing Witnesses have occurred very infrequently over the last 95 years.

Q. WHAT IS YOUR RESPONSE TO MR. O'DONNELL'S CRITICISMS OF YOUR EMPIRICAL CAPM ("ECAPM") ANALYSIS?

A. Mr. O'Donnell suggests that the ECAPM method is a discretionary adjustment "utilized when an analyst feels as though the weighted risk premium will help to correct for returns that were too high or too low for stocks with low Betas (*i.e.*, those stocks that are deemed to be less risky than the overall market) or high Betas (*i.e.,* those stocks that are deemed to be more risky than the overall market), respectively"[109] I disagree with his characterization.

As explained in my direct testimony, the ECAPM reflects published research findings that confirm companies with lower Beta coefficients tend to

[109] Direct Testimony of Kevin W. O'Donnell, at 92.

have higher returns than those predicted by the CAPM, and those with higher Beta coefficients tend to have lower returns than expected.[110] Consequently, it is a more precise application of the CAPM analysis, consistent with academic literature.

Q. ARE YOU AWARE OF ANY ACADEMIC LITERATURE SUPPORTING THE APPLICATION OF THE ECAPM TO THE UTILITY INDUSTRY?

A. Yes, I am. In a 2011 study by Stéphane Chrétien and Frank Coggins, the authors studied the CAPM's ability to estimate the risk premium for the utility industry in particular subgroups of utilities, including a group of U.S. natural gas utilities.[111] The study considered the traditional CAPM approach, the Fama-French three-factor model, and a model similar to the ECAPM I apply. As Chrétien and Coggins show, the ECAPM significantly outperformed the traditional CAPM model at predicting the observed risk premium for the various utility subgroups. Their model showed that the CAPM underestimated the risk premium for U.S. natural gas distribution utilities by as much as 7.39 percent and was statistically significant.

Q. HAS THE COMMISSION ACCEPTED THE ECAPM IN PRIOR PROCEEDINGS?

A. Yes, it has. In its February 24, 2020 Order in Docket No. E-22, Sub 562 for Dominion Energy North Carolina, the Commission found the ECAPM analysis

---

[110] Direct Testimony of Jennifer E. Nelson, at 40-41.
[111] Stéphane Chrétien and Frank Coggins, *Cost Of Equity for Energy Utilities: Beyond The CAPM*, Energy Studies Review, Vol. 18, No. 2 (2011).

presented in that proceeding to be "credible, probative, and entitled to substantial weight."[112]

C. Risk Premium Analysis

Q. AS A PRELIMINARY MATTER, DO THE OPPOSING WITNESSES TAKE ISSUE WITH YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS?

A. It does not appear so. Mr. O'Donnell does not appear to take issue with my Bond Yield Plus Risk Premium model itself and Mr. Hinton does not comment on it.

Q. PLEASE SUMMARIZE MR. HINTON'S RISK PREMIUM REGRESSION ANALYSIS METHOD.

A. Mr. Hinton performs a Risk Premium regression analysis similar in concept to my Bond Yield Plus Risk Premium analysis, except he uses Moody's A-rated utility bond yield instead of the 30-year Treasury bond yield as the independent variable. We both agree that natural gas utility authorized ROEs represent a reasonable proxy for the investor-required cost of equity and that there is a statistically significant inverse relationship between the Equity Risk Premium and bond yields.[113]

---

[112] *In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina,* Order Accepting Public Staff Stipulation In Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, And Granting Partial Rate Increase, NCUC Docket No. E-22, Sub 562, at 40 (February 24, 2020).
[113] Direct Testimony of John R. Hinton, at 35-36; Direct Testimony of Jennifer E. Nelson, at 45.

Q. DO YOU HAVE ANY CONCERNS WITH MR. HINTON'S RISK PREMIUM ANALYSIS?

A. Yes, my concern is that his analysis does not consider forward-looking projections of bond yields. Because the Cost of Equity is forward-looking, forward-looking bond yields should be used. If Mr. Hinton had used projected yields, his result would have been 9.76 percent.

I calculated a projected Moody's A-rated utility bond yield by first relying on a consensus forecast of 50 economists of the expected yield on Moody's Baa-rated corporate bonds for the six calendar quarters ending with the fourth calendar quarter of 2022, and *Blue Chip Financial Forecasts'* ("*Blue Chip")* long-term projections for 2023 to 2027, and 2028 to 2032.[114] According to *Blue Chip,* the average expected yield on Moody's Baa-rated corporate bonds is 4.72 percent. I then subtracted 13 basis points, which is equal to the average daily spread in Moody's Baa-rated corporate bond yields and Baa-rated utility bond yields over the last five years,[115] for an expected yield on Moody's Baa-rated utility bonds of 4.59 percent. Lastly, I subtracted another 33 basis points, which represents the average spread between Moody's A-rated utility bonds and Moody's Baa-rated utility bonds between March 2020 and August 2021 shown on page 27 of Mr. Hinton's direct testimony (*i.e.*, the "three-notch spread"). Subtracting the recent 0.33 percent spread from the expected Moody's

[114] *See*, *Blue Chip Financial Forecasts*, Vol. 40, No. 9 September 1, 2021, at 2 and Vol. 40, No. 6 June 1, 2021, at 14, consistent with my calculation of the projected 30-year Treasury yield from *Blue Chip.*
[115] Sources: Federal Reserve Bank of St. Louis FRED Database, and Bloomberg Professional.

Baa-rated utility bond yield of 4.59 percent results in an expected Moody's A-rated utility bond yield of 4.26 percent. Applying the projected A-rated utility bond yield estimate of 4.26 percent to Mr. Hinton's Regression Analysis coefficients produces a Risk Premium-based Cost of Equity estimate of 9.76 percent.[116]

Q. MR. O'DONNELL ASSERTS THE EQUITY RISK PREMIA INCLUDED IN YOUR BOND YIELD PLUS RISK PREMIUM ANALYSIS ARE "MORE THAN DOUBLE THE OVERALL HISTORICAL MARKET RETURNS" HE PRESENTS IN HIS TABLE 8.[117] IS HE CORRECT?

A. No, he is not. It is unclear what Mr. O'Donnell's argument is. The 7.04 percent and 7.89 percent equity risk premia that result from my regression analysis are *below* his historical market returns for large company stocks of 10.7 percent (geometric average) and 12.1 percent (arithmetic average), not more than double as he asserts. If his point is that my 7.04 percent and 7.89 percent equity risk premia are "more than double" his resulting market risk premia of 2.7 percent (geometric average) and 3.4 percent (arithmetic average), the discrepancy resides in Mr. O'Donnell's calculation of the market risk premium.

Putting aside the point that the equity risk premia estimated in my Bond Yield Plus Risk Premium analysis is not based on historical returns on large company stocks, as discussed earlier, the long-term historical average market

---

[116] 9.76% = 0.08679 + 0.25425 x 4.26%.
[117] Direct Testimony of Kevin W. O'Donnell, at 93.

risk premium Mr. O'Donnell calculates is incorrect because he subtracts an average *total* return on long-term government bonds from an average total return on large capitalization stocks rather than the average *income* return on long-term government bonds.

Consequently, the equity risk premia estimated in my Bond Yield Plus Risk Premium analysis is not inconsistent with historical data. Furthermore, it reflects the inverse relationship between interest rates and risk premiums.

D. Comparable Earnings Analysis

Q. PLEASE SUMMARIZE THE OPPOSING WITNESSES' COMPARABLE EARNINGS ANALYSES.

A. Both Mr. Hinton and Mr. O'Donnell perform a Comparable Earnings Analysis; however, neither rely substantially on it in determining their ROE recommendation. Mr. Hinton's analysis is historical looking, reviewing the earned return on book equity reported by *Value Line* for his proxy companies for the years 2015 to 2020.[118] From this data, he calculates a mean of 10.00 percent and a median of 9.50 percent, and concludes that his median value is the appropriate Comparable Earnings-based Cost of Equity estimate due in part to a 20.20 percent earned ROE for National Fuel Gas in 2018.[119]

In developing his Comparable Earnings-based Cost of Equity estimate, Mr. O'Donnell first reviews the same earned return on book equity from *Value*

---

118 Hinton Exhibit 9.
119 Direct Testimony of John R. Hinton, at 37-38; Hinton Exhibit 9.

Line for his proxy companies in 2019 and 2020, but also reviews *Value Line's* projected return on book equity for 2021 and the 2024-2026 period.[120] As a second measure, Mr. O'Donnell reviews the average authorized ROE for LDCs from 2006 to 2020. From this data, he concludes that a Comparable Earnings-based Cost of Equity estimate is between 9.00 percent and 10.00 percent.[121] As explained earlier in Section II above, I do not believe Mr. O'Donnell's review of the trend in the annual average authorized ROE is placed in the proper context. Moreover, his 9.00 percent ROE recommendation is far removed from the data he presents and would represent a significant departure from returns expected for, or available to, other natural gas utilities.

Q. IN YOUR OPINION, IS THE COMPARABLE EARNINGS METHOD AN APPROPRIATE METHOD TO ESTIMATE THE COST OF EQUITY IN THIS PROCEEDING?

A. Although I have not performed a Comparable Earnings Analysis in this proceeding, in my opinion, it is generally a reasonable approach as it satisfies the *Hope* and *Bluefield* comparable return standard. However, because the Cost of Equity is forward-looking, only projected ROE estimates from the analysis should be given weight.

I disagree, however, with Mr. O'Donnell's position that the fact the model is not a market-based approach renders it less reliable than other

[120] Direct Testimony of Kevin W. O'Donnell, at 65; Exhibit KWO-4.
[121] Direct Testimony of Kevin W. O'Donnell, at 68.

methods.[122] The authorized ROE established in this case will be applied to the net book value of the Company's rate base, subject to certain regulatory adjustments. In this regard, the Comparable Earnings approach is informative because it provides a measure of the return on book value that is available to investors through other investments with comparable risk to PSNC. As Dr. Morin notes, "because the investment base for ratemaking purposes is expressed in book value terms, a rate of return on book value, as is the case with Comparable Earnings, is highly meaningful."[123]

Q. WHAT WOULD MR. HINTON'S AND MR. O'DONNELL'S COMPARABLE EARNINGS ANALYSIS-BASED RECOMMENDATIONS BE IF THEY RELIED ONLY ON FORWARD-LOOKING ESTIMATES?

A. As shown in Nelson Rebuttal Exhibit 11, I updated Hinton Exhibit 9 to include *Value Line*'s five-year return on book equity projections for his proxy group. The average and median expected return on book equity for his proxy group is 10.45 percent and 10.50 percent, respectively, for the years 2024-2026. As Exhibit KWO-4 shows, Mr. O'Donnell's forward-looking Comparable Earnings-based ROE estimates are each 9.70 percent. Because these estimates are consistent with the prospective nature of the Cost of Equity, they are the only ones that should be given weight.

[122] Direct Testimony of Kevin W. O'Donnell, at 48.
[123] Roger A. Morin Ph.D., New Regulatory Finance, Public Utility Reports, Inc., at 394-395 (2006).

E. Business Risks and Other Considerations

Q. MR. HINTON SUGGESTS PSNC IS LESS RISKY ON ACCOUNT OF CERTAIN OF ITS REGULATORY MECHANISMS. WHAT IS YOUR RESPONSE?

A. Mr. Hinton references the Company's Integrity Management Tracker ("IMT") and Customer Utilization Tracker ("CUT") to support his position that the Company's risk is reduced on account of these mechanisms, as well as for the reasonableness of his 9.48 percent ROE recommendation.[124] Mr. Collins also suggests the Commission "consider the IMR and any other mechanisms which provide PSNC with additional cost recovery outside of a base rate case in setting a reasonable ROE."[125] However, Mr. Hinton's and Mr. Collins' positions do not reflect the fact that 11 of the 12 Combined Proxy Group companies also have similar mechanisms. As shown in Nelson Rebuttal Exhibit 12, 34 of the 47 operating companies within the Combined Proxy Group have a mechanism to recover capital expenditures outside base rate cases. Additionally, 38 of the same 47 operating companies have a mechanism to mitigate volumetric risk[126] akin to the Company's CUT mechanism. Because the Cost of Equity is a comparative exercise, as discussed below, the Company is no less risky than its peers on account of its regulatory mechanisms.

---

[124] Direct Testimony of John R. Hinton, at 39-42.
[125] Direct Testimony of Brian D. Collins, at 16.
[126] *E.g.,* Weather normalization adjustment, lost revenue adjustment mechanisms, and decoupling mechanisms.

Developing the Cost of Equity necessarily is a comparative assessment, as the analytical models are applied to a proxy group of comparable companies. As such, even if it were the case that regulatory mechanisms mitigate "risk," they only would affect the Cost of Equity if: (1) the effect of the mechanism was to reduce risk below the levels faced by the subject company's peers in the proxy group; and (2) investors knowingly reduced their return requirements for the Company as a direct consequence of the mechanisms. Because capital cost recovery and decoupling mechanisms are also employed by the Combined Proxy Group companies as shown in Nelson Rebuttal Exhibit 12, PSNC is no less risky than its peers.

The Company's regulatory mechanisms simply render it more comparable to its peers. Because such mechanisms are common among the proxy group, to the extent these regulatory mechanisms reduce a utility's risk, any risk-reducing effects are reflected in the proxy group and, therefore, in the market data and analytical results that underlie my recommended ROE range. Consequently, my recommendation, and the analyses on which it is based, reflect any effect of PSNC's regulatory mechanisms on investors' perceptions of the Company's risk.

Q. MR. HINTON ASSERTS YOU "RECOMMEND THAT THE COST OF EQUITY INCLUDE AN ADDER OF 45 BASIS POINTS TO ACCOUNT FOR PSNC'S SMALL SIZE."[127] IS HE CORRECT?

A. No. My direct testimony is clear that I am not proposing an explicit adjustment to account for PSNC's small size relative to the proxy group; rather, I have considered it in determining my overall recommendation.[128]

Q. MR. O'DONNELL STATES A SIZE PREMIUM IS NOT WARRANTED BECAUSE "PSNC IS A SUBSIDIARY OF A LARGER COMPANY, DOMINION ENERGY."[129] WHAT IS YOUR RESPONSE?

A. As explained in my direct testimony[130] (and noted earlier regarding the capital structure), under the standalone principle of ratemaking, each utility subsidiary is treated as its own company and are valued on a sum-of-the-parts basis. Therefore, it is important that the authorized ROE reflects the risks and prospects of the regulated utility's operations and supports the regulated utility's financial integrity from a stand-alone perspective.

---

[127] Direct Testimony of John R. Hinton, at 4.
[128] Direct Testimony of Jennifer E. Nelson, at 50-51.
[129] Direct Testimony of Kevin W. O'Donnell, at 93.
[130] Direct Testimony of Jennifer E. Nelson, at 48-49.

VI. ECONOMIC CONDITIONS IN NORTH CAROLINA

Q. HAVE YOU UPDATED YOUR ANALYSES REGARDING THE CURRENT ECONOMIC CONDITIONS IN NORTH CAROLINA?

A. Yes, I have updated the same analyses presented in my direct testimony to reflect data available as of mid-September 2021. As discussed below, my conclusion in my direct testimony that economic conditions in North Carolina were highly correlated with the U.S. economy continues to hold. Specifically:

- Unemployment at both the state and county level continues to decline and remains highly correlated with national rates of unemployment. The unemployment rates in North Carolina (both statewide and for the counties PSNC serves) continue to fall and remain below the national unemployment rate (*see* Nelson Rebuttal Exhibits 13 and 14);
- Real Gross Domestic Product ("GDP") grew year-over-year in North Carolina and the U.S. in Q1 2021 and remains highly correlated with U.S. real GDP growth (*see* Nelson Rebuttal Exhibit 15); 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 (*see* Nelson Rebuttal Exhibit 16).

On balance, the correlations between statewide measures of economic conditions noted by the Commission in Docket No. E-22, Sub 479 remain in place and, as such, they continue to be reflected in the models used to estimate the Cost of Equity.

Q. MR. O'DONNELL CITES TO NATIONAL UNEMPLOYMENT FIGURES, CONCLUDING THAT UNEMPLOYMENT REMAINS ABOVE HISTORICAL BENCHMARKS.[131] HOW DO YOU RESPOND?

A. I agree that unemployment figures remain above those immediately preceding the COVID-19 pandemic; however, the average unemployment rate in 2019 was the lowest annual average unemployment rate since 1969, whereas the long-term average unemployment rate since 1948 has been approximately 5.80 percent.[132] From that perspective, the current unemployment rate as of July 2021 for the U.S. (5.40 percent) and North Carolina (4.40 percent)[133] are below the long-term average unemployment rate.

VII. UPDATED ANALYTICAL RESULTS

Q. PLEASE SUMMARIZE YOUR UPDATED ANALYTICAL RESULTS.

A. I have updated the Constant Growth DCF model, Quarterly Growth DCF, CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses based on data through August 31, 2021, and applied to the same proxy group presented in my direct testimony. I also prepared DCF and CAPM analyses using the Combined Proxy Group. In my direct testimony, I removed three outlier growth rates from my DCF analyses.[134] In my updated analyses, I excluded *Value Line's* 19.00

---

[131] Direct Testimony of Kevin W. O'Donnell, at 18-19.
[132] Source: U.S. Bureau of Labor Statistics, Unemployment Rate (Seasonally Adjusted), January 1948 – August 2021.
[133] Nelson Rebuttal Exhibit 13.
[134] Direct Testimony of Jennifer E. Nelson, at 28-29.

percent projected earnings growth rate for National Fuel Gas as it was excluded by Mr. Hinton.[135]

The results of my updated analyses are summarized in Tables 11a and 11b below.

Table 11a: Summary of Updated DCF Results[136]

Constant Growth DCF Nelson Proxy Group	**Low**	**Mean**	**High**
30-Day Average	8.50%	9.60%	11.21%
90-Day Average	8.44%	9.62%	11.07%
180-Day Average	8.57%	9.73%	11.18%
Quarterly Growth DCF Nelson Proxy Group	**Low**	**Mean**	**High**
30-Day Average	8.69%	9.79%	11.50%
90-Day Average	8.63%	9.81%	11.34%
180-Day Average	8.77%	9.93%	11.46%
Constant Growth DCF Combined Proxy Group	**Low**	**Mean**	**High**
30-Day Average	8.78%	10.05%	12.00%
90-Day Average	8.73%	10.02%	12.02%
180-Day Average	8.86%	10.16%	12.18%
Quarterly Growth DCF Combined Proxy Group	**Low**	**Mean**	**High**
30-Day Average	9.00%	10.18%	11.73%
90-Day Average	8.94%	10.16%	11.69%
180-Day Average	9.09%	10.28%	11.83%

135 *See* Hinton Exhibit 7.
136 Nelson Rebuttal Exhibit 1 through Nelson Rebuttal Exhibit 4. Average of the proxy group mean and median results.

Table 11b: Summary of Updated Risk Premium-based Results[137]

Bond Yield Plus Risk Premium		
Current 30-Year Treasury Yield (1.91%)	9.85%	
Projected 30-Year Treasury Yield (3.03%)	9.76%	
CAPM[138]	**Current 30-Year Treasury Yield (1.91%)**	**Projected 30-Year Treasury Yield (3.03%)**
Nelson Proxy Group Average	13.74%	13.85%
Nelson Proxy Group Median	13.08%	13.25%
Combined Proxy Group Average	13.90%	14.00%
Combined Proxy Group Median	13.08%	13.25%
Empirical CAPM[139]	**Current 30-Year Treasury Yield (1.91%)**	**Projected 30-Year Treasury Yield (3.03%)**
Nelson Proxy Group Average	14.07%	14.15%
Nelson Proxy Group Median	13.58%	13.70%
Combined Proxy Group Average	14.19%	14.26%
Combined Proxy Group Median	13.58%	13.70%

VIII. CONCLUSIONS

Q. WHAT IS YOUR CONCLUSION REGARDING THE ROE AND CAPITAL STRUCTURE FOR PSNC?

A. As discussed throughout my Rebuttal Testimony, the outcome of this proceeding will have important implications on the Company's ability to maintain its financial profile necessary to provide safe, reliable service to the benefit of customers. Based on the analyses discussed throughout my Rebuttal Testimony, I continue to conclude that a reasonable and conservative range of

[137] Nelson Rebuttal Exhibits 5 to 7.
[138] Using the *Value Line*-based Market Risk Premium estimate and *Value Line* Beta coefficients.
[139] Using the *Value Line*-based Market Risk Premium estimate and *Value Line* Beta coefficients.

ROE estimates is from 9.60 percent to 10.75 percent, and within that range, 10.25 percent remains a reasonable and conservative estimate of PSNC's Cost of Equity. The results of the DCF, CAPM, ECAPM, and Bond Yield Plus Risk Premium analyses using data through August 31, 2021, for both my and the Opposing Witnesses' proxy groups, continue to support the reasonableness of my range of ROE estimates and my recommendation.

As to the capital structure, a capital structure including 54.86 percent common equity, 1.34 percent short-term debt, and 43.80 percent long-term debt is consistent with capital structures in place at the proxy companies and would enable the Company to maintain its credit ratings and financial profile. Therefore, I conclude it is reasonable and should be approved.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET G-5, SUB 632
DOCKET G-5, SUB 634

SETTLEMENT TESTIMONY

OF

JENNIFER E. NELSON

OCTOBER 15, 2021

TABLE OF CONTENTS

I. INTRODUCTION AND PURPOSE

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

A. My name is Jennifer E. Nelson. I am an Assistant Vice President at Concentric Energy Advisors. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts 01742.

Q. ARE YOU THE SAME JENNIFER E. NELSON WHO SUBMITTED DIRECT AND REBUTTAL TESTIMONIES IN THIS PROCEEDING?

A. Yes, I am. I filed direct testimony ("Direct Testimony") and rebuttal testimony ("Rebuttal Testimony") on behalf of Public Service Company of North Carolina, Inc. ("PSNC" or the "Company"), in which I recommended a Return on Equity ("ROE") of 10.25 percent, within a range of 9.60 percent to 10.75 percent.[1]

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

A. The purpose of my testimony is to explain my support for the Stipulation of Settlement, dated October 15, 2021 (the "Stipulation") among the Company and the Public Staff – North Carolina Utilities Commission , Carolina Utility Customers Association, Inc., and Evergreen Packaging, LLC (collectively, the "Settling Parties"). My testimony addresses the agreed-upon ROE ("Stipulated ROE"), capital structure ("Stipulated Capital Structure"), and

[1] Direct Testimony of Jennifer E. Nelson, at 3; Rebuttal Testimony of Jennifer E. Nelson, at 75-76.

overall rate of return ("Stipulated ROR") contained in the Stipulation.

Q. HAVE YOU PREPARED ANY EXHIBITS IN CONJUNCTION WITH YOUR SETTLEMENT TESTIMONY?

A. Yes, Nelson Settlement Exhibit 1 and Nelson Settlement Exhibit 2 were prepared by me or under my direction.

II. STIPULATED ROE, CAPITAL STRUCTURE, AND ROR

Q. ARE YOU FAMILIAR WITH THE TERMS OF THE STIPULATION AS IT RELATES TO THE COMPANY'S ROE, CAPITAL STRUCTURE, AND ROR?

A. Yes. I understand the Settling Parties have agreed to the Stipulated ROR of 7.07 percent based on the capital structure and cost rates shown in Table 1 below.

Table 1: Stipulated Rate of Return[2]

	Capital Ratio	Cost	Weighted Cost
Long-Term Debt	47.06%	4.48%	2.108%
Short-Term Debt	1.34%	0.25%	0.003%
Common Equity	51.60%	9.60%	4.954%
Total	100.00%		7.065%

Q. IN GENERAL, DO YOU SUPPORT THE COMPANY'S DECISION TO AGREE TO THE STIPULATED ROE, CAPITAL STRUCTURE, AND ROR?

A. Yes, I do. As discussed throughout my Direct and Rebuttal Testimonies, the models used to estimate the ROE produce a wide range of estimates.[3] It is my position that in a fully litigated proceeding, an ROE between 9.60 percent and

---

[2] *See*, Docket No. G-5, Sub 632, Stipulation of Settlement, October 15, 2021.

[3] *See, e.g.*, Direct Testimony of Jennifer E. Nelson, at 17.

10.75 percent represents the range of returns required by equity investors for PSNC based on recent market data. The Stipulated ROE of 9.60 percent is at the low end of that range. Further, I recognize the benefits associated with the decision to enter into the comprehensive settlement of all issues. Therefore, in my opinion, the 9.60 percent Stipulated ROE is a reasonable resolution of an otherwise contentious issue. Lastly, I understand the Company has determined that the terms of the Stipulation, including the Stipulated ROE, Stipulated Capital Structure, and Stipulated ROR would be viewed by the rating agencies as constructive and equitable. I understand and respect that determination.

Q. HAVE YOU REVIEWED THE STIPULATED ROE AND STIPULATED ROR IN THE CONTEXT OF RETURNS AUTHORIZED FOR OTHER NATURAL GAS DISTRIBUTION UTILITIES?

A. Yes, I have. Since the Commission's order in the Company's last rate case, the average and median ROE authorized for natural gas distribution utilities in rate cases reported by Regulatory Research Associates ("RRA") were each 9.60 percent.[4] Additionally, 88 of the 160 (*i.e.*, 55.00 percent) natural gas distribution rate cases covered by RRA since the Company's last rate case authorized an ROE of 9.60 percent or higher (*see* Nelson Settlement Exhibit 1).[5]

---

[4] *See* Nelson Settlement Exhibit 1.

[5] Source: Regulatory Research Associates. Natural gas distribution utility rate cases reported between November 1, 2016 and October 13, 2021. *See also* Nelson Settlement Exhibit 1.

During the same period, the average and median authorized rate of return were 7.14 percent and 7.15 percent, respectively; 88 of 149 natural gas distribution rate cases (*i.e.*, 59.06 percent) authorized an overall rate of return of 7.07 percent and higher.[6] From that perspective, the Stipulated ROE and Stipulated ROR are consistent with, if not somewhat conservative relative to returns recently authorized for natural gas distribution utilities.

In my Rebuttal Testimony, I reviewed the current authorized equity ratios for the operating companies within the proxy group companies considered by the ROE witnesses.[7] For a similar perspective, I gathered the current authorized ROEs for the proxy group companies in each jurisdiction in which they operate, and calculated average and median current authorized ROE statistics from two perspectives (*see* Nelson Settlement Exhibit 2). Under the first perspective, if the current authorized ROE in each individual operating subsidiary is given equal weight, the average and median current authorized ROE is 9.73 percent and 9.75 percent respectively, with 31 of 48 operating subsidiaries (*i.e.*, 64.58 percent) having a current authorized ROE of 9.60 percent or higher.[8] Under the second perspective, if the current authorized ROE

[6] Source: Regulatory Research Associates. Natural gas distribution utility rate cases reported between November 1, 2016 and October 13, 2021. Excludes rate cases in jurisdictions that include non-investor supplied capital in the ratemaking capital structure (*i.e.*, Arkansas, Florida, Indiana, and Michigan). *See also* Nelson Settlement Exhibit 1.

[7] Rebuttal Testimony of Jennifer E. Nelson, at 23-25.

[8] Sources: Regulatory Research Associates; individual company 2020 10-Ks. *See* Nelson Exhibit 2. This approach gives equal weight to the current authorized ROE of each individual operating subsidiary. Under this approach, the current authorized ROE for a proxy company with more operating subsidiaries would account for a greater share of the average than a proxy company with fewer operating subsidiaries.

for each proxy company reflects the average of its operating subsidiaries, the average current authorized ROE for the proxy group is 9.67 percent and the median is 9.60 percent.[9]

Q. ARE THERE OTHER DISTINCTIONS THAT ARE IMPORTANT TO CONSIDER WHEN REVIEWING AUTHORIZED RETURNS?

A. Yes, there are. As explained in my Direct Testimony, the regulatory environment is a key driver of investors' risk assessment for utilities.[10] For example, 50.00 percent of the factors that Moody's considers in its credit ratings determination are related to the nature of regulation.[11] Given PSNC's ongoing need to access external capital and the weight rating agencies and investors place on the nature of the regulatory environment, it is reasonable to assess the Stipulated ROE and Stipulated ROR with those available to natural gas distribution utilities in jurisdictions viewed as having constructive regulatory environments.

Q. IN GENERAL, IS NORTH CAROLINA CONSIDERED TO HAVE A CONSTRUCTIVE REGULATORY ENVIRONMENT?

A. Yes. RRA is a widely referenced source of rate case data that assesses the extent to which regulatory jurisdictions are constructive from investors'

[9] This approach gives equal weight to each proxy company that reflects the average of its operating subsidiaries. Under this approach, the current authorized ROE for a single operating subsidiary would account for a greater share of a proxy company average with fewer operating subsidiaries than for a proxy company with more operating subsidiaries.

[10] Direct Testimony of Jennifer E. Nelson, at 15.

[11] Direct Testimony of Jennifer E. Nelson, at 15-16.

perspectives.[12] In my Rebuttal Testimony filed on October 7, 2021, I noted that North Carolina was ranked "Average/1" according to RRA.[13] On October 13, 2021, RRA raised its ranking for North Carolina from "Average/1" to "Above Average/3," noting recent legislation that improved the constructiveness of the state's regulatory environment, combined with authorized returns that have been slightly above the national average at the time established.[14]

Q. HOW HAVE YOU CONSIDERED THOSE DISTINCTIONS IN YOUR REVIEW OF THE STIPULATED ROR?

A. In my Rebuttal Testimony, I discussed the distinction in authorized ROEs for natural gas distribution utilities in more constructive regulatory jurisdictions relative to less constructive jurisdictions.[15] I performed a similar review of the Stipulated ROR relative to the overall rate of return authorized for natural gas distribution utilities in more constructive jurisdictions. As shown in Table 2 below and in Nelson Settlement Exhibit 1, the average and median authorized rate of return for natural gas utilities in jurisdictions rated "Above Average/3" and higher (that is, as constructive or better than North Carolina) since the Company's last rate case is 7.35 percent and 7.30 percent respectively.[16] The

---

[12] Rebuttal Testimony of Jennifer E. Nelson, at 10.
[13] Rebuttal Testimony of Jennifer E. Nelson, at 10.
[14] RRA Regulatory Focus, "Recent events signal shift in regulatory risk for NC, Ariz. Utilities," October 13, 2021.
[15] Rebuttal Testimony of Jennifer E. Nelson, at 10-11.
[16] Excludes rate cases in jurisdictions that include non-investor supplied capital in the ratemaking capital structure (*i.e.*, Arkansas, Florida, Indiana, and Michigan).

Stipulated ROR of 7.07 percent is approximately 28 and 23 basis points below those benchmarks, respectively.

Table 2: Authorized Rate of Return by RRA Ranking[17]

	RRA Ranking: Above Average/3 and Higher	RRA Ranking: Average/1 and Lower
Average	7.35%	7.11%
Median	7.30%	7.13%
High	7.88%	8.59%
Low	6.85%	5.75%

As demonstrated from the data above, the Stipulated ROR is low relative to the overall rates of return authorized in other jurisdictions. The low overall rate of return contained in the Stipulation 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 opinion, the settlement maintains that support, and produces the overall rate of return on which customer rates would be set. From that important perspective, the Stipulated ROR strikes the necessary balance between customer and investor interests.

[17] Source: Regulatory Research Associates for natural gas distribution rate cases completed between November 1, 2016 and October 13, 2021. Excludes rate cases in jurisdictions that include non-investor supplied capital in the ratemaking capital structure (*i.e.*, Arkansas, Florida, Indiana, and Michigan).

Q. HOW DOES THE STIPULATED CAPITAL STRUCTURE COMPARE TO EQUITY RATIOS AUTHORIZED RECENTLY FOR NATURAL GAS DISTRIBUTION UTILITIES?

A. In my Rebuttal Testimony, I performed several analyses relating to the capital structures recently authorized for natural gas utilities. In particular, the 51.60 percent equity ratio included in the Stipulated Capital Structure is somewhat below the average and median authorized equity ratio for natural gas utilities in jurisdictions ranked "Average/1" and higher between 2019-2021 (*i.e.*, 52.60 percent and 52.02 percent, respectively).[18] Additionally, since PSNC's last rate case, the average and median authorized equity ratio for natural gas distribution utilities was 51.66 percent and 51.81 percent, respectively.[19]

Given RRA's upgrade of the regulatory environment in North Carolina since the filing of my Rebuttal Testimony, I also reviewed the average and median authorized equity ratio for natural gas utilities in jurisdictions ranked "Above Average/3" and higher since the Company's last rate case. As shown in Table 3 below, the 51.60 percent equity ratio included in the Stipulated Capital Structure falls between the average and median authorized equity ratios for natural gas distribution utilities in jurisdictions ranked "Above Average/3" and higher, and those authorized in jurisdictions ranked "Average/1" and lower.

---

[18] Rebuttal Testimony of Jennifer E. Nelson, at 22, Table 4.

[19] *See* Nelson Settlement Testimony 1. Source: Regulatory Research Associates for natural gas distribution rate cases completed between November 1, 2016 and October 13, 2021. Excludes rate cases in jurisdictions that include non-investor supplied capital in the ratemaking capital structure (*i.e.*, Arkansas, Florida, Indiana, and Michigan).

Table 3: Authorized Equity Ratio by RRA Ranking[20]

	RRA Ranking: Above Average/3 and Higher	RRA Ranking: Average/1 and Lower
Average	53.28%	51.37%
Median	52.52%	51.38%
High	59.64%	60.18%
Low	49.23%	42.90%

Based on my review of the data presented above, the 51.60 percent equity ratio contained in the Stipulated Capital Structure is a reasonable resolution to an otherwise contentious issue.

Q. BASED ON YOUR ANALYSES PRESENTED ABOVE DO YOU BELIEVE THE STIPULATION IS REASONABLE?

A. Yes. Based on the data shown above, I conclude the Stipulated ROE, Stipulated Capital Structure, and Stipulated ROR, as components of the comprehensive settlement reached by the parties, contribute to a reasonable resolution of all issues in this proceeding.

Q. LASTLY, DOES YOUR TESTIMONY CONSIDER THE ECONOMIC CONDITIONS IN NORTH CAROLINA?

A. Yes, it does. I understand and appreciate the Commission's need to balance the interests of investors and customers, as well as its requirement to consider economic conditions in North Carolina as it sets rates. As explained in both my Direct and Rebuttal Testimonies, I recognize that economic conditions are

[20] Source: Regulatory Research Associates. Natural gas distribution utility rate cases reported between November 1, 2016 and October 13, 2021. Excludes rate cases in jurisdictions that include non-investor supplied capital in the ratemaking capital structure (*i.e.*, Arkansas, Florida, Indiana, and Michigan). *See* Nelson Settlement Exhibit 1.

improving in North Carolina and across the U.S.[21] Because North Carolina's economic conditions remain highly correlated to the economic conditions nationally,[22] my review of North Carolina's economic conditions does not alter my conclusion that the Stipulated ROE, Capital Structure, and ROR are reasonable resolutions to otherwise contentious issues.

Q. DOES THIS CONCLUDE YOUR SETTLEMENT TESTIMONY?

A. Yes, it does.

[21] Direct Testimony of Jennifer E. Nelson, at 51-60; Rebuttal Testimony of Jennifer E. Nelson, at 72.
[22] *See*, Rebuttal Testimony of Jennifer E. Nelson, at 72.

MS. GRIGG: Thank you, ma'am. Ms. Nelson is available for questions -- for cross-examination and Commission questions.

COMMISSIONER BROWN-BLAND: All right. Is there cross-examination for this witness?

MS. FORCE: Madam Chairman, can you hear me, Margaret Force?

COMMISSIONER BROWN-BLAND: Yes, I -- I do hear you, Ms. Force.

CROSS-EXAMINATION BY MS. FORCE:

Q. Okay. I just have a few for you, Ms. Nelson.

A. Okay.

Q. I am going to be referring to a proposed Cross Exhibit Number 1 that was submitted by the Attorney General's Office. Do you have that?

A. Yes, I do.

Q. Great.

A. Yes, I do have that.

Q. I'll come back to that then. The questions relate to the debt part of PSNC's capital structure. And you testified about the capital structure in your initial testimony. Isn't that right?

A. I did.

MS. FORCE: Okay. And I'd ask that the item that we're looking at be marked as AGO Nelson Cross Exhibit 1. And, Madam Chairman, this is the proposed Cross Exhibit 1, and it is identified at the top by Public Service Company North Carolina and shows -- it -- I will submit to you that this is the G-1 -- from the G-1 Number -- Item Number 35 that's been filed in this docket on April 1st.

BY MS. FORCE:

Q. So we're looking at the same thing, right, Ms. Nelson?

A. Yes.

COMMISSIONER BROWN-BLAND: All right. That document will be allowed as AGO Cross-Examination Exhibit --

MS. FORCE: That's right.

COMMISSIONER BROWN-BLAND: AGO Nelson Cross-Examination Exhibit 1.

MS. FORCE: Right. Thank you.

(Nelson Cross-Examination Exhibit 1 was marked for identification.)

BY MS. FORCE:

Q. And if you'll turn to Page 2 of that exhibit, Ms. Nelson, you'll see a list of the long-term debt outstanding from PSNC. Do you see that?

A. Yes, I do.

Q. It's called Senior Debentures here. Is -- is the

significance of that term, "Debentures," that this is unsecured debt? Do you know?
A. I do not know for sure.
Q. That's okay. The -- the list doesn't show these issuances from -- the -- any order in which they were issued. If you look at what's marked Column 2 -- it's really more like the fourth column -- it lists the date of issue for these securities. Do you see that?
A. Yes, I do.
Q. Okay. And if you look at those in the column for 1996 and -- let's see. It goes all the way to 2020, but if you look at the early and late 1996, they have rates of 6.99 and 7.45. And then another issuance that just matured this year was at 6.54 percent for debt. Is that right?
A. I see that, yes. That's correct.
Q. But the more recent issuances, 2011 through March of 2020, all reflect reduced cost rates that decreased to 4.59 percent or less. Would you agree?
A. Yes. Yes.
Q. And most recently, 4.05 percent?
A. Yes. Showing on this exhibit, 4.05 percent is the most recent. I do understand that the company updated this exhibit or this information as part of its supplemental testimony, and there was an additional issuance at 3.10

percent, I believe. Yes, 3.10 percent.

Q. Thank you. That's helpful. And that -- that was something that was issued between the time that the rate case was filed and June, I presume?

A. It was issued between the end of the test year, which was December 31st of 2020, and June 30th.

Q. Okay. Thank you. And in the last rate case, the rate of return used as the cost of long-term debt was 5.52 percent, is that right, as you looked at that, the last case?

A. So is your question that the authorized embedded cost of debt was five-point --

Q. Yes.

A. I don't know that off the top of my head, but I would accept that subject to check.

Q. I appreciate that. And I've referred to the Commission's rate order in the last case that was issued October 28th, 2016, and G-5's 565.

So with that background, is it fair to say that the rate for the cost of debt has been reducing over the past decade?

A. Yes.

MS. FORCE: Okay. Those are my questions and I don't have any other. I appreciate this opportunity. And I guess when we're done, I'd ask that the exhibit be admitted into evidence.

COMMISSIONER BROWN-BLAND: All right. It's my understanding that the Attorney General's Office was the only party having cross for this witness. Is that correct?

MS. FORCE: That's correct.

COMMISSIONER BROWN-BLAND: All right. I don't hear anyone else speaking up. So redirect, Ms. Grigg?

MS. GRIGG: No redirect.

COMMISSIONER BROWN-BLAND: All right. Are there questions from the Commission?

(No response.)

COMMISSIONER BROWN-BLAND: I'm not hearing any. So this is the appropriate time to receive into evidence AGO Nelson Cross-Examination 1. It shall be received and --

MS. GRIGG: Thank you very much.

COMMISSIONER BROWN-BLAND: -- Ms. Nelson, you may be excused.

THE WITNESS: Okay. Thank you.

COMMISSIONER BROWN-BLAND: Thank you so much.

(AGO Nelson Cross-Examination Exhibit 1 was received into evidence.)

MS. GRIGG: Madam Presiding Chair --

COMMISSIONER BROWN-BLAND: Yes.

MS. GRIGG: Madam Presiding Chair Brown-Bland --

COMMISSIONER BROWN-BLAND: Yes.

MS. GRIGG: -- may I move Ms. -- may I move Ms. Nelson's exhibits into evidence at this time as well?

COMMISSIONER BROWN-BLAND: Yes. I already identified exhibits from -- from direct, rebuttal and settlement will be received into evidence at this time.

MS. GRIGG: Thank you, ma'am.

COMMISSIONER BROWN-BLAND: Now you may be excused.

THE WITNESS: Thank you.

MS. GRIGG: PSNC now calls Mr. James A. Spaulding to the stand.

COMMISSIONER BROWN-BLAND: All right. Mr. Spaulding, are you ready?

MR. SPAULDING: I am. Can you hear me?

COMMISSIONER BROWN-BLAND: Yes, I do. All right. We're just waiting for you to show up. There you are.

(WHEREUPON,

JAMES A. SPAULDING,

having been duly affirmed, testified as follows:)

COMMISSIONER BROWN-BLAND: All right. Ms. Grigg?

MS. GRIGG: Thank you, ma'am.

DIRECT EXAMINATION BY MS. GRIGG:

Q. Good morning, Mr. Spaulding.

A. Good morning.
Q. Would you please state your name and business address for the record?
A. My name is James A. Spaulding, and my business address is 800 Gaston Road, Gastonia, North Carolina 28056.
Q. By whom are you employed and in what capacity?
A. I'm employed by Dominion Energy Services, Inc., a subsidiary of Dominion Energy, Inc., as Manager, Financial and Business Services for Public Service Company of North Carolina, doing business as Dominion Energy North Carolina.
Q. Did you cause to be prefiled in these dockets on April 1st, 2021, 21 pages of direct testimony and seven (7) exhibits?
A. Yes, I did.
Q. Do you have any changes or corrections to your direct testimony or exhibits?
A. No, I do not.
Q. If I were to ask you the same questions that appear in your direct testimony today, would your answers be the same?
A. Yes, they would.
Q. Mr. Spaulding, did you also cause to be prefiled in these dockets on August 10th, 2021, 16 pages of supplemental testimony and eight (8) exhibits?

A. I did.
Q. Do you have any changes or corrections to your supplemental testimony or exhibits?
A. I do not.
Q. If I were to ask you the same questions that appear in your supplemental testimony today, would your answers be the same?
A. Yes, they would.
Q. Mr. Spaulding, did you also cause to be prefiled in these dockets on October 7th, 2021, ten (10) pages of rebuttal testimony?
A. I did.
Q. Do you have any changes or corrections to your rebuttal testimony?
A. I do not.
Q. And if I were to ask you the same questions that appear in your rebuttal testimony today, would your answers be the same?
A. Yes, they would.
Q. And, finally, Mr. Spaulding, did you also cause to be prefiled in these dockets on October 15th, 2021, five (5) pages of settlement testimony?
A. I did.
Q. Do you have any changes or corrections to your

settlement testimony?
A. I do not.
Q. If I were to ask you the same questions that appear in your settlement testimony today, would your answers be the same?
A. Yes, they would.
Q. Mr. Spaulding, did you prepare a summary of your testimonies?
A. I did.
Q. Would you please now present your summary for the Commission?
A. Yes. After the filing of my direct, supplemental and rebuttal testimonies, PSNC reached a Stipulation of Settlement with Public Staff, Carolina Utilities Customers Association, Inc., and Evergreen Packaging, LLC, resolving all issues in this proceeding.
My settlement testimony provides general support for the Stipulation and explains economic adjustments to the company's revenue requirement resulting from the Stipulation. The Stipulation is the product of give-and-take negotiations between the stipulating parties. I conclude that the Stipulation's adjustments to revenues and rates is fair, just and reasonable and should be approved.
Q. Thank you, Mr. Spaulding.

MS. GRIGG: Commissioner Brown-Bland, the witness is available for questions.

COMMISSIONER BROWN-BLAND: All right. Ms. Grigg, did you want to move his testimony?

MS. GRIGG: Yes, ma'am. I would move that Mr. Spaulding's seven (7) direct exhibits and eight (8) supplemental exhibits be moved into evidence.

COMMISSIONER BROWN-BLAND: I was referring to his direct -- his prefiled direct --

MS. GRIGG: Oh, I'm sorry.

COMMISSIONER BROWN-BLAND: -- and rebuttal --

MS. GRIGG: I'm sorry. Yes, ma'am. I move that the prefiled direct, supplemental, rebuttal and settlement testimonies of Mr. Spaulding be copied into the record as if given orally from the stand and that his seven (7) direct exhibits and eight (8) supplemental exhibits be marked for identification as prefiled.

COMMISSIONER BROWN-BLAND: And that motion will be allowed.

MS. GRIGG: Thank you.

(Spaulding Direct Exhibits 1 through 7 and Spaulding Supplemental Exhibits 1 through 8 were marked for identification.)

(Whereupon, the prefiled direct, prefiled supplemental, prefiled rebuttal and prefiled settlement testimonies of James A. Spaulding were copied into the record as if given from the stand.)

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632

DIRECT TESTIMONY

OF

JAMES A. SPAULDING

APRIL 1, 2021

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

A. My name is James A. Spaulding. My business address is 800 Gaston Road, Gastonia, North Carolina 28056. I am employed by Dominion Energy Services, Inc. ("DESI"), a subsidiary of Dominion Energy, Inc. ("DEI"), as Manager – Financial & Business Services for Public Service Company of North Carolina, Inc., doing business as Dominion Energy North Carolina ("PSNC" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND, WORK EXPERIENCE, AND OTHER QUALIFICATIONS.

A. I graduated with distinction from the University of North Carolina at Chapel Hill in 1995 with a Bachelor of Science Degree in Business Administration. Additionally, I received a Master of Accounting degree from the University of North Carolina at Chapel Hill in 1997. In the same year, I was employed by KPMG International Ltd. in Charlotte and, for the next three years, worked in its audit department. In February 1999, I became a Certified Public Accountant. I joined PSNC in 2001 as a Senior Financial Analyst and was promoted to Accountant – Lead in 2006 and to Manager – Financial and Gas Accounting in 2008. I assumed my current title and responsibilities in December 2019 following the merger of SCANA Corporation with DEI.

Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE THIS COMMISSION?

A. Yes, in the Company's last general rate case, Docket No. G-5, Sub 565.

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

A. My testimony supports PSNC's proposed revenue increase and, specifically, addresses adjustments to rate base, depreciation, operations and maintenance ("O&M") expenses, and income tax expense. It also addresses other accounting issues, including issues related to certain Financial Accounting Standards Board ("FASB") standards and interpretations, excess deferred income taxes ("EDIT") resulting from the federal Tax Cuts and Jobs Act of 2017 ("TCJA") and from state income tax reductions, and allowance for funds used during construction ("AFUDC"). The following exhibits are included with my testimony.

Spaulding Direct Exhibit 1	End of Period Net Investment
Spaulding Direct Exhibit 2	Accumulated Depreciation and Amortization
Spaulding Direct Exhibit 3	Materials and Supplies
Spaulding Direct Exhibit 4	Working Capital
Spaulding Direct Exhibit 5	Statement of Net Operating Income
Spaulding Direct Exhibit 6	Net Operating Income and Rates of Return
Spaulding Direct Exhibit 7	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 PSNC?

A. Yes. The books of PSNC, for the test period, follow the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission ("FERC"). The test period amounts reflected in the exhibits are those represented on PSNC's books and all the pro forma adjustments shown on the exhibits conform to the Company's accounting procedures.

Q. WHAT TEST PERIOD DID THE COMPANY USE IN THIS PROCEEDING?

A. The test period used in this proceeding is the twelve months ended December 31, 2020.

Q. PLEASE EXPLAIN SPAULDING DIRECT EXHIBIT 1.

A. Page 1 of Spaulding Direct Exhibit 1 is a summary of PSNC's total end-of-period net investment in the amount of $1,546,483,051. Gross utility plant in service is presented on pages 2 and 3; the total amount at the end of the test year was $2,783,691,172.

Q. PLEASE EXPLAIN SPAULDING DIRECT EXHIBIT 2.

A. Spaulding Direct Exhibit 2 is a schedule of PSNC's accumulated depreciation and amortization on utility plant in service as of December 31, 2020, in the amount of $878,126,128. The schedule is presented by plant account, and current depreciation rates are presented for each account. The current depreciation rates are those from the study prepared by Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming") based on plant in service as of December 31, 2015. These depreciation rates were approved by the Commission in Docket No. G-5, Sub 565.

Q. IS PSNC PROPOSING NEW DEPRECIATION RATES IN THIS PROCEEDING?

A. Yes. Gannett Fleming prepared a depreciation study based on utility plant in service as of December 31, 2020. The details and results of this study are found in the direct testimony of Company witness Spanos. PSNC is requesting that this study be approved by the Commission.

Q. WHAT IS THE IMPACT OF THE PROPOSED DEPRECIATION RATES ON THIS PROCEEDING?

A. PSNC prepared an adjustment to depreciation expense on the estimated plant in service as of June 30, 2021. Using the proposed rates, the adjustment decreases annual depreciation expense by $1,888,568. The calculation of this adjustment is found in Form G-1, Item 4a, Workpaper 4D.

Q. PLEASE EXPLAIN SPAULDING DIRECT EXHIBIT 3.

A. Spaulding Direct Exhibit 3 presents both the end-of-period and 13-month average balances of materials and supplies and gas in storage for the test year. The average balance of $45,155,646 is used in the computation of working capital on page 1 of Exhibit 4.

Q. PLEASE EXPLAIN SPAULDING DIRECT EXHIBIT 4.

A. Spaulding Direct Exhibit 4 presents PSNC's calculated working capital allowance of $6,857,775 included in net investment on Spaulding Direct Exhibit 1. The first component of $12,353,701 is the result of PSNC's lead-lag analysis found in Form G-1, Item 26. The Company updated the lead and lag days based on 2019 cost of service activity. The resulting lead and lag days were applied to the 2020 cost of service to determine the level of investor supplied funds to be included in rate base. Other additions to working capital include average materials and supplies, average gas inventories (as shown in Spaulding Direct Exhibit 3), and average prepayments. The working capital allowance has been reduced by the 13-month average for the test year of customer deposits, interest accrued on customer deposits, accrued vacation liability, state sales taxes, the deferred account that tracks the clearing of customer refund checks, and several cost-free capital items.

Q. PLEASE EXPLAIN SPAULDING DIRECT EXHIBIT 5.

A. Spaulding Direct Exhibit 5 is a statement of net operating income per books for the test year in the amount of $118,470,372.

Q. PLEASE EXPLAIN SPAULDING DIRECT EXHIBIT 6.

A. Page 1 of Spaulding Direct Exhibit 6 summarizes PSNC's operating income and end-of-period rate of return on three bases: per books (column 1); after adjustments (column 3); and after the proposed rate increase (column 5). Column 2 includes the accounting and pro forma adjustments necessary to state expenses and utility plant on a going-level basis; column 4 shows the adjustments for the proposed rate increase. Corresponding capitalization statements for columns 1, 3, and 5 are presented on page 2 of the exhibit, and the proposed adjustments from columns 2 and 4 are listed on pages 3 through 5.

Q. PLEASE EXPLAIN THE ADJUSTMENTS, BEGINNING WITH ADJUSTMENT 1 IN COLUMN 2 OF SPAULDING DIRECT EXHIBIT 6, PAGE 1.

A. Adjustment 1 increases gas sales and transportation revenues by $63,938,532. This adjustment is discussed in the testimony of Company witness Hinson, and the computation can be found in Form G-1, Item 4a, Workpaper 1.

Adjustment 2 annualizes the cost of gas at PSNC's present $2.50 per dekatherm "benchmark" commodity price. This adjustment also includes the fixed gas costs. All PSNC gas costs are subject to an annual prudence review pursuant to N.C. Gen. Stat. § 62-133.4. The computation of pro forma cost of gas can be found in Form G-1, Item 4, Workpaper 2, and is discussed further in the testimony of Company witness Hinson.

Adjustment 3 increases O&M expenses by $30,838,345. This adjustment reflects 25 separate adjustments, which I will discuss later in my testimony.

Adjustment 4 is a net increase to test year depreciation expense due largely to the estimated net plant additions through June 30, 2021, notably the T-30 project, which is discussed by Company witness Randall. This adjustment also includes additional depreciation expense allocated to PSNC from DESI based on plant estimated as of June 30, 2021. It includes a decrease due to the proposed depreciation rates discussed in the testimony of Company witness Spanos and a reduction for an allocation to non-utility operations.

Adjustment 5 increases general taxes by $4,502,926. This adjustment addresses ad valorem taxes on adjusted plant balances and franchise taxes. It also increases Federal Insurance Contributions Act taxes related to the increases in payroll discussed below.

Adjustments 6 and 7 show the effect of state and federal income taxes, respectively, from all the other adjustments, net of adjustments for deferred income tax provisions, which are separately shown in Adjustments 6.1 and 7.1.

Adjustments 6.1 and 7.1 reflect the estimated federal and state deferred income tax provisions, respectively, to be recorded between January 1, 2021, and June 30, 2021.

Adjustment 8 increases utility plant for estimated net additions through June 30, 2021, which includes $215,000 in research and development investment discussed later in my testimony. This adjustment also decreases utility plant for an allocation to non-utility plant.

Adjustment 9 increases the reserve for depreciation and amortization of utility plant for the anticipated change between the end of the test year and June 30, 2021, net of an allocation to non-utility plant.

Adjustment 10 is an increase to working capital for the projected decrease in the other postemployment benefits accrual and for an increase to prepayments related to the state franchise tax.

Adjustment 10.1 is an increase in the lead-lag portion of working capital after pro forma adjustments. This is explained further in adjustment 16.

Adjustment 11 is an increase in accumulated deferred income taxes ("ADIT") for the anticipated change between the end of the test year and June 30, 2021, net of an allocation to non-utility operations.

Adjustment 12, in gas sales and transportation revenues, reflects the proposed revenue requirement of $53,145,476, which is the increase required to give PSNC the opportunity to earn the rate of return requested in this docket.

Adjustments 13 through 15 reflect changes in regulatory fees, uncollectibles expense, and state and federal income taxes resulting from the proposed revenue increase. These adjustments increase net operating income by $40,783,970 and produce a return on investment of 7.64% and a return on common equity of 10.25%.

Adjustment 16 in column 4 reflects the adjustment to the lead-lag component of cash working capital ("CWC") resulting from the proposed adjustment to revenues and its impact on cost of service in adjustments 12 through 15. In its May 5, 2015 order on lead-lag study procedure in Docket No. M-100, Sub 137, the Commission concluded that, as a general rule, in future determinations of CWC for major electric and natural gas utilities, lead-lag studies would be based upon fully-adjusted, pro forma, test-period levels of revenues and costs, including the full effects of any approved rate increases or decreases.

Q. PLEASE DESCRIBE THE O&M ADJUSTMENTS IN SPAULDING DIRECT EXHIBIT 6.

A. As I stated earlier, adjustment 3 to Spaulding Direct Exhibit 6 increases O&M expenses by $30,838,345 and is comprised of the following specific adjustments:

A. An increase in PSNC's O&M payroll costs to:
   - Annualize non-union salaries effective in March of 2021, and union salary changes effective in December of 2021.
   - Increase headcount by 35 employees anticipated to be hired between December 31, 2020, and June 30, 2021. PSNC instituted a hiring freeze following the onset of the COVID-19 pandemic. During the first six months of 2021, PSNC expects to fill 35 positions that will return its headcount to normal levels.
   - Reflect a 3% increase in salaries charged to PSNC by DESI. DESI provides administrative services such as legal, accounting, human resources, information systems, and contact center support. The 3% increase is representative of the merit salary adjustments awarded to eligible non-union employees in March of 2021.

B. Reclassification of interest expense on customer deposits as an operating expense as approved in prior general rate cases.

C. An increase in the regulatory fee based upon the adjustment to revenues as detailed in the testimony of Company witness Hinson.

D. An increase in pension costs as a reflection of the most current actuarial analysis.

E. A decrease in other postretirement employee benefit costs, principally health care benefits, to match the amounts to be accrued for these future expenses under the Company's most recent actuarial study.

F. An increase in 401(k) expenses and other employee benefits related to the above changes in compensation.

G. A decrease in uncollectible costs to reflect current provision levels based on recent write-offs as a percentage of the adjusted revenues detailed in the testimony of Company witness Hinson.

H. An increase to reflect additional customer accounts expense resulting from the customer growth portion of the revenue adjustment discussed in the testimony of Company witness Hinson.

I. A decrease in expenses for the amortization of manufactured gas plant.

J. An increase in expenses for the amortization of projected rate case expenses over three years.

K. An increase to reflect the amortization of the balance of deferred transmission pipeline integrity management program ("TIMP") expenses. PSNC deferred O&M expenses for its TIMP in accordance with the Commission's order in Docket No. G-5, Sub 565. As of December 31, 2020, the TIMP regulatory asset was $65,616,564 and an additional $6 million is projected through June 30, 2021. The Company proposes to amortize these costs over five years.

L. An increase to recognize inflation occurring in O&M accounts that are not adjusted or annualized individually. The 2.64% inflation factor utilized was based upon the 2021 forecasted Consumer Price Index, which is a measure of the expected change in the prices of consumer durable goods and services.

M. An increase in DESI charges to the going level.

N. A decrease in certain O&M expenses for a non-utility allocation.

O. An increase for the cost of transportation to remove a non-recurring compressed natural gas tax credit that occurred during the test year due to federal legislation.

P. An increase in the amortization over five years of the balance of distribution integrity management program ("DIMP") expenses. PSNC deferred O&M expenses for its DIMP in accordance with the Commission's order in Docket No. G-5, Sub 565. As of December 31, 2020, the DIMP regulatory asset was $33,637,800 and an additional $5.55 million is projected through June 30, 2021.

Q. An increase to reflect postage expenses after applying the growth rate.

R. A decrease to move certain costs to non-utility expenses.

S. An increase to incentive compensation for both short-term and long-term accruals. Short-term incentive compensation was adjusted to reflect an average three-year (2018-2020) pay-out percentage. Long-term incentive compensation is based on the annualized accrual as of February 28, 2021.

T. An increase in the fuel cost of PSNC's fleet.

U. A decrease in mileage expense to reflect the most recent Internal Revenue Service rate.

V. A decrease to remove a non-recurring long-term disability medical credit.

W. A decrease to remove conservation program costs due to the Company proposing a rider to recover these costs.

X. An increase to reflect higher excess liability premiums.

Y. An increase in research and development expenses. This is discussed in Company witness Randall's testimony.

Q. PLEASE EXPLAIN SPAULDING DIRECT EXHIBIT 7.

A. Pages 1 and 2 of Spaulding Direct Exhibit 7 are PSNC's balance sheet as of December 31, 2020, and page 3 is its income statement for the twelve months ended December 31, 2020.

Q. HOW HAS PSNC TREATED THE BOOK ACCOUNTING RELATED TO FASB'S ACCOUNTING STANDARDS CODIFICATION ("ASC") 715 *COMPENSATION – RETIREMENT BENEFITS*?

A. ASC 715, which codified and superseded FASB's Statement of Financial Accounting Standards ("SFAS") No. 158, requires an employer to recognize the overfunded or underfunded status of a defined benefit pension or other postretirement plan as an asset or liability in its statement of financial position and to recognize changes in that funded status in the year in which changes occur through accumulated other comprehensive income. In Docket No. G-5, Sub 485, the Commission approved PSNC's request to place all impacts to its other comprehensive income caused by SFAS No. 158 in regulatory deferred accounts. The Commission's January 5, 2007 order approving the request stated that approval of the deferred accounting treatment was to have no impact on the Company's operating results or return on rate base for regulatory purposes. Although it had no material effect on the accounting treatment discussed here, SFAS No. 158 was superseded by ASC 715. As of December 31, 2020, PSNC had recorded a regulatory asset of $16,190,606 related to ASC 715. Offsets were posted to pension assets, postretirement liabilities, and ADIT. The impact of ASC 715 was removed from all accounts before computing PSNC's rate base, net operating income, and common equity.

Q. HAS PSNC FOLLOWED ANY OTHER ACCOUNTING PRONOUNCEMENTS THAT YOU WOULD LIKE TO DISCUSS?

A. Yes. PSNC has removed the book accounting impact of ASC 410, *Asset Retirement and Environmental Obligations*, which codified and superseded FASB's Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47"), in the computation of rate base, net operating income for return, and regulatory return on common equity in accordance with the Commission's order in Docket No. G-5, Sub 474, dated January 11, 2006. This order authorized PSNC to place in regulatory deferred accounts any differences in its income statement caused by the adoption of FIN 47, stating that such deferred accounting treatment was to have no impact on the Company's operating results or return on rate base for regulatory purposes. Although it had no material effect on the accounting treatment discussed here, FIN 47 was superseded by ASC 410. As of December 31, 2020, PSNC had recorded an asset retirement obligation of $85,922,603 and a regulatory deferred asset of $22,462,132, with the difference booked in utility plant and accumulated depreciation.

Q. PLEASE PROVIDE AN OVERVIEW OF THE TCJA AND ITS IMPACT ON PSNC AND ITS CUSTOMERS.

A. The key provisions of the TCJA that affect customer rates are: (1) a reduction of the corporate income tax rate from 35% to 21%; (2) elimination of bonus depreciation; and (3) continuation of the normalization requirements of depreciation-related balances resulting from the TCJA. Customers will benefit from a reduction in the revenue requirement reflecting the lower corporate income tax rate and the amortization of EDIT.

Q. PLEASE EXPLAIN.

A. ADIT represents a fund of available cost-free capital that is created by reducing a utility's tax liability when tax deductions like accelerated depreciation are claimed. This fund is reflected in the utility's ADIT balance, memorializing the fact that an amount of tax has been deferred but must be repaid later. Until such repayment, the utility has the use of the funds on a cost-free basis.

It was anticipated that the ADIT would eventually have to be paid back to the government in the form of higher income taxes when, later in the life of the depreciable assets, book depreciation would exceed the available tax depreciation deductions. However, the reduction in the income tax rate enacted as part of the TCJA altered the amount of the anticipated repayment liability. Consequently, some portion of the ADIT reserve previously recorded on the presumption that it would be taxed at 35% is rendered unnecessary for that purpose. This portion is EDIT.

Q. PLEASE EXPLAIN THE DIFFERENCE BETWEEN "PROTECTED EDIT" AND "UNPROTECTED EDIT."

A. Protected EDIT represents the excess of the ADIT reserve required by the normalization rules (that is, the ADIT reserve attributable to accelerated depreciation). The TCJA requires that Protected EDIT be flowed to customers no faster than ratably over the life of the timing difference that gave rise to the excess. "Unprotected EDIT" can be flowed to customers in a timeframe set at the regulator's discretion.

Q. PLEASE DESCRIBE HOW PSNC PROPOSES TO FLOW THROUGH THE BENEFITS OF THE TCJA TO CUSTOMERS.

A. PSNC proposes to address a portion of the TCJA benefits, as well as state EDIT benefits, through riders and to address the remaining portion of the TCJA benefits through base rates.

Q. PLEASE DESCRIBE THE RIDERS PROPOSED BY PSNC.

A. The following riders are outlined below and are further described in the testimony of Company witness Hinson:

Rider EDIT-1 Amortization of Federal Excess Deferred Income Taxes Rider

Rider EDIT-2 Federal Tax Act Revenue Deferred From Overcollections Rider

Rider EDIT-3 State Excess Deferred Income Taxes Rider

Q. PLEASE EXPLAIN PROPOSED RIDER EDIT-1.

A. PSNC is proposing Rider EDIT-1 to return to customers the benefits of Unprotected EDIT balances, including amortized and re-deferred Protected EDIT, for the period January 1, 2018, through December 31, 2020, that have not yet been flowed through to customers. The primary component of this balance is Protected EDIT that has been amortized under the average rate assumption method ("ARAM") and re-deferred as a separate regulatory liability. PSNC's depreciation system automatically calculates the ARAM amortization on protected balances. Rather than attempt to override the system calculations, which could result in inadvertent normalization violations, PSNC manually made entries to re-establish the regulatory liability for this amortization. Since this amortization has already impacted income tax expense, it is deemed to be Unprotected EDIT and available to be flowed to customers subject to approval by the Commission. PSNC proposes this balance of $9,390,162, as of December 31, 2020, be flowed to customers over a seven-year period through the Amortization of Federal EDIT Rider.

Q. PLEASE EXPLAIN PROPOSED RIDER EDIT-2.

A. While the effective date of the TCJA was January 1, 2018, PSNC continued to collect a 35% federal income tax in customer rates through December 31, 2018, until the Commission, in Docket No. M-100, Sub 148, authorized PSNC to pass through the lower 21% federal income tax rate effective with bills rendered on and after January 1, 2019. As a result, PSNC over-collected $17,640,715, including carrying costs, as of December 31, 2020. PSNC is proposing to use Rider EDIT-2 to refund this balance to its customers over a two-year period.

Q. PLEASE DESCRIBE RIDER EDIT-3.

A. State EDIT results from prior state corporate income tax rate reductions and the correction noted in the Company's filing in Docket No. M-100, Sub 138. The Company is proposing to use Rider EDIT-3 to flow through to customers the combined amount of $3,660,326, as of December 31, 2020, over a five-year period.

Q. PLEASE DESCRIBE HOW PSNC IS ADDRESSING ANY OTHER EDIT BALANCES.

A. As of the end of 2020, PSNC had three tranches of other EDIT regulatory liabilities or assets on its books. The regulatory liabilities are reflected as reductions to rate base and the regulatory asset is reflected as an increase to rate base.

The first tranche contains a liability of approximately $150 million related to accelerated depreciation. Under normalization rules this reserve is Protected EDIT, which can be flowed through to customers no faster than the underlying timing differences reserve using the ARAM. Since PSNC is using the ARAM this reserve will be reflected in the Company's base rates.

The second tranche contains a liability of approximately $0.4 million that relates to property, plant, and equipment. This balance is Unprotected

EDIT, which is subject to collection in a timeframe open to discretionary action by the Commission. PSNC proposes to flow this balance through base rates over 7 years.

The third tranche is an asset of approximately $0.8 million not related to investment property, plant, or equipment. This balance is Unprotected EDIT. PSNC proposes to recover this balance through base rates over 7 years.

Q. PLEASE PROVIDE AN EXPLANATION OF AFUDC.

A. PSNC, like many utilities, is engaged in significant capital-intensive construction projects. These projects often take a significant amount of time to complete, potentially resulting in the incurrence of substantial financing costs in advance of when the facilities are ready for use. Through AFUDC these financing costs are included in allowable capital costs for future ratemaking purposes and recovery. ASC 980-835-30-1 requires capitalization of AFUDC if the utility's regulator provides for its recovery. The primary difference between AFUDC and interest capitalized under ASC 835 is that AFUDC includes a component for equity funds.

Q. IS IT APPROPRIATE FOR UTILITIES TO CAPITALIZE THE EQUITY COMPONENT OF AFUDC?

A. Yes. PSNC utilizes both debt and equity to fund operations as it maintains the capital structure described in the testimony of Company witness Phibbs. Accordingly, it is appropriate that AFUDC recognize both forms of funding. Just as debt holders require payment of interest for the money that they lend the

Company, equity holders require compensation, such as dividends, for their investment in the Company.

Q. WHAT IS THE INCOME TAX IMPACT RESULTING FROM CAPITALIZING AFUDC?

A. If AFUDC is capitalized, the regulated utility records a corresponding increase in pre-tax income for the component for equity funds ("AFUDC Equity"). AFUDC Equity capitalized for accounting and regulatory purposes is a component of construction cost and is depreciated once the utility plant is placed in service (i.e., it gives rise to accounting basis). However, for income tax purposes, neither the amount originally capitalized for accounting purposes nor the subsequent depreciation of that amount influences the determination of taxable income. Because AFUDC Equity is not capitalized into utility plant for tax purposes (i.e., it does not give rise to a tax basis), the book basis of utility plant will exceed the tax basis of utility plant by the capitalized AFUDC Equity amount.

The accounting for AFUDC Equity is like a flow-through and results in a deferred tax liability in accordance with ASC 980-740-25-1(b). Flow-through occurs when the regulator excludes deferred income tax expense or benefit from recoverable costs when determining income tax expense for ratemaking. In other words, customer rates are based on current tax expense with future income tax benefits and charges flowed through to customers.

Under ASC 740, *Income Taxes,* deferred tax assets or liabilities are required to be recognized on temporary differences, whether flowed through or not; however, the FERC typically permits recovery of the AFUDC Equity through depreciation without an income tax effect. Therefore, AFUDC Equity capitalized for accounting purposes results in the recognition of a deferred tax liability and a "grossed-up" regulatory asset. The gross regulatory asset represents probable future revenue related to the recovery of future income taxes related to the AFUDC Equity temporary difference.

Q. WHAT ACCOUNTING TREATMENT IS THE COMPANY PROPOSING FOR AFUDC?

A. The Company is requesting recovery of the regulatory asset of approximately $13.3 million, which represents the under-recovered AFUDC Equity regulatory asset balance recorded on PSNC's books as of December 31, 2020, and reflected in rate base in the current filing. To be clear, the Company is not requesting a retroactive recovery of all previously accrued AFUDC Equity. Instead, the balance in this account represents the cumulative revenue shortfall related to AFUDC Equity. This balance includes accruals of AFUDC Equity and depreciation of that AFUDC Equity, such that this is a net under-recovered balance as of December 31, 2020.

Q. IS THE COMPANY MAKING ANY OTHER ACCOUNTING TREATMENT PROPOSALS?

A. Yes. The Company is requesting Commission approval of the accounting treatment for the capital investment related to the research and development initiative discussed in Company witness Randall's testimony. This is also referenced in my testimony above with respect to adjustments 3.Y and 8 shown in Spaulding Direct Exhibit 6. PSNC is proposing to invest $215,000 in capital equipment, including a hydrogen chromatograph and hydrogen/natural gas blending equipment. Since this project is a research and development project, the Company proposes to account for this capital investment as experimental gas plant unclassified (FERC Account GL 103).

Q. WHAT ACCOUNTING TREATMENT IS THE COMPANY REQUESTING?

A. The Company is asking the Commission to approve of the Company's proposed research and development investment, whereby this capital project would be included in rate base. Prior to transfer to gas plant in service (FERC Account GL 101), the subject plant must be certified by the Commission for use as gas plant in service.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes; however, I plan to offer information pertaining to relevant changes in costs, revenues, property, returns, or any other accounting matters that occur after the filing of my testimony. Also, I reserve the right to supplement or amend my testimony before or during the Commission's hearing.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

SUPPLEMENTAL TESTIMONY

OF

JAMES A. SPAULDING

AUGUST 10, 2021

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

A. My name is James A. Spaulding. My business address is 800 Gaston Road, Gastonia, North Carolina 28056. I am employed by Dominion Energy Services, Inc., as Manager – Financial & business Services for Public Service Company of North Carolina, Inc., doing business as Dominion Energy North Carolina ("PSNC" or the "Company").

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

A. The purpose of my supplemental testimony is to update PSNC's rate case filing as permitted by N.C. Gen. Stat. § 62-133(c) and Commission Rule R1-17(c). In the Company's application in this proceeding filed on April 1, 2021, PSNC specifically reserved its right to make these updates. In that filing, PSNC based its revenue request on a number of pro forma adjustments that were developed on the basis of estimated going-level expense and utility rate base as of June 30, 2021. I will update the Company's proposed pro forma adjustment to reflect actual costs and rate base adjustments as of June 30, 2021.

Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR UPDATE TESTIMONY?

A. Yes.

Q. WERE YOUR SUPPLEMENTAL EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. PLEASE DESCRIBE YOUR SUPPLEMENTAL EXHIBITS.

A. Spaulding Supplemental Exhibits 1 through 8 were prepared for this supplemental filing.

Spaulding Supplemental Exhibit 1	End of Period Net Investment
Spaulding Supplemental Exhibit 2	Accumulated Depreciation and Amortization
Spaulding Supplemental Exhibit 3	Materials and Supplies
Spaulding Supplemental Exhibit 4	Working Capital
Spaulding Supplemental Exhibit 5	Statement of Net Operating Income
Spaulding Supplemental Exhibit 6	Net Operating Income and Rates of Return
Spaulding Supplemental Exhibit 7	Balance Sheet and Income Statement
Spaulding Supplemental Exhibit 8	Lead Lag Study

Q. PLEASE EXPLAIN THE UPDATES TO PRO FORMA UTILITY RATE BASE REFLECTED IN YOUR SUPPLEMENTAL EXHIBITS.

A. Spaulding Supplemental Exhibit 1 summarizes the components of rate base. The first column in this exhibit shows end of test period rate base is approximately $1,546.5 million. In the original application, PSNC anticipated that rate base would grow to approximately $1,748.2 million through June 30, 2021 and used this amount in the revenue request computation in Spaulding

Direct Exhibit 6. PSNC's actual rate base as of June 30, 2021, is approximately $1,703.1 million. I updated the revenue request computation to this actual rate base amount on page 1 of Spaulding Supplemental Exhibit 6.

Q. WAS EACH COMPONENT OF PRO FORMA UTILITY RATE BASE UPDATED USING ACTUAL AMOUNTS AS OF JUNE 30, 2021?

A. Yes. Nothing about this supplemental filing changes the per books test period amounts shown in PSNC's original application and in my direct testimony. The test period for this general rate case proceeding continues to be the 12-months ending December 31, 2020. This update filing simply uses the now known actuals at June 30, 2021, to update: 1) the pro forma utility rate base adjustments in the Company's original application that were developed based on then-estimated June 30, 2021, figures and amounts; and 2) certain pro forma expense adjustments in the Company's original application that were developed based on then-estimated June 30, 2021, figures and amounts. The largest component of rate base is utility plant in service. Spaulding Supplemental Exhibit 1 identifies utility plant in service by asset category at the end of the test period and as of June 30, 2021. Spaulding Supplemental Exhibit 2 identifies accumulated depreciation by asset category at the end of the test period and as of June 30, 2021. Spaulding Supplemental Exhibits 3 and 4 identify the components of allowance for working capital, which for the test period is the

13-month average balance ended December 31, 2020, and on a pro forma basis, is the 13-month average balance ended June 30, 2021.

Q. PLEASE EXPLAIN THE UPDATES TO PRO FORMA DEPRECIATION EXPENSE REFLECTED IN YOUR SUPPLEMENTAL EXHIBITS.

A. In the original application, PSNC presented a pro forma adjustment to depreciation expense that was aligned with the pro forma amount of utility plant in service as estimated at June 30, 2021. PSNC has updated the computation of depreciation expense to reflect actual utility plant in service as of June 30, 2021. The Company's revenue request computation shown on page 3 of Spaulding Supplemental Exhibit 6 incorporates this updated pro forma depreciation expense amount.

Q. PLEASE EXPLAIN THE UPDATES TO PRO FORMA OPERATIONS AND MAINTENANCE ("O&M") EXPENSE REFLECTED IN YOUR SUPPLEMENTAL EXHIBITS.

A. In the Company's original application, and discussed on pages 9 through 12 of my direct testimony, there were 25 discrete pro forma adjustments to the test period level of O&M expense. With June 30, 2021, actuals being known and available, the Company has updated seven adjustments and added one new adjustment to the pro forma O&M expense adjustments. The pro forma O&M adjustments currently proposed, including explanations for the seven that were updated and the new adjustment, are shown in Table A below. I updated the revenue request computation for the overall impact of the updated pro forma O&M expenses on page 1 of Spaulding Supplemental Exhibit 6.

Table A

Adj #	**Adjustment Amount ($)**	**Adjustment Narrative**
3A	1,457,460	**To increase salaries & wages expense to the going-level basis.** This adjustment consists of several calculations as follows: (1) PSNC annualized non-union salaries in effect as of March 1, 2021, and union salary changes effective December 2020 to calculate pro forma compensation for the test period. (2) PSNC anticipated additional employees to be hired between December 31, 2020, and June 30, 2021. (3) PSNC included a pro forma adjustment to reflect a 3% increase in salaries charged to PSNC by DES. **<u>Per Supplemental Filing</u>**: This adjustment update reflects actual employee headcount and wage rates as of June 30, 2021, in lieu of the estimated headcount and wage rates used in the application.
3B	556,625	**To increase expense for interest on customer deposits.** This adjustment reclassifies the interest on customer deposits from Other Interest Expense to Operating Expense as approved in the prior general rate case. **<u>Per Supplemental Filing</u>**: No change from the application was made.

Adj #	Adjustment Amount ($)	Adjustment Narrative
3C	30,361	To increase current regulatory fee expense to the going-level. PSNC calculated the pro forma operating revenues subject to the NCUC regulatory fee using the current regulatory fee rate. **Per Supplemental Filing**: No change from the application was made.
3D	66,830	**To increase pension expense to the going-level basis.** This adjustment reflects the difference between the O&M portion of the test period pension expense and the pro forma pension expense per the most current actuarial analysis. **Per Supplemental Filing**: No change from the application was made.
3E	(186,099)	**To decrease other postretirement employee benefit ("OPEB") expense to the going-level basis.** This adjustment reflects the difference between the O&M portion of the test period OPEB expense and the pro forma OPEB expense per the most current actuarial analysis. **Per Supplemental Filing**: No change from the application was made.

Adj #	Adjustment Amount ($)	Adjustment Narrative
3F	150,183	**To increase 401(k) expense and other employee benefits expense to the going-level basis following adjustment 3A.** This adjustment reflects the increase in 401(k) expenses and other employee benefits related to the changes in compensation from Adjustment 3A. **Per Supplemental Filing**: This adjustment update is to align with the update for Adjustment 3A discussed above and reflects actual employee headcount and wage rates as of June 30, 2021, in lieu of the estimated headcount and wage rates used in the application.
3G	(138,978)	**To decrease the provision of uncollectible expense to the going-level basis.** PSNC adjusted uncollectible expense by calculating the adjusted test period revenues using the growth adjusted test period gas sales and transportation revenues from Adjustment 4a.1, less the gas cost component of heat sensitive customers. **Per Supplemental Filing**: No change from the application was made.
3H	31,919	**To increase expenses to reflect customer growth.** This adjustment calculates the amount of customer accounts expense that should be subject to the growth factor. **Per Supplemental Filing**: No change from the application was made.

Adj #	Adjustment Amount ($)	Adjustment Narrative
3I	(1,349,826)	**To decrease the regulatory amortization expense for deferred manufactured gas plant costs.** As this regulatory asset will be fully amortized as of October 2021, the pro forma adjustment was to recognize that this expense will no longer be incurred and should not be included in future rates. **Per Supplemental Filing**: No change from the application was made.
3J	279,134	**To increase the regulatory amortization expense for deferred rate case costs.** PSNC estimated expenses associated with the 2021 rate case and proposed a 3-year amortization period for these costs. The current balance will be fully amortized by October 31, 2021. **Per Supplemental Filing**: This adjustment update reflects actual rate case expenses through June 30, 2021 including expert witness contracted amounts in lieu of estimated expenses used in the application.
3K	12,926,785	**To increase the regulatory amortization expense for deferred transmission pipeline integrity management program costs.** The unamortized deferred transmission pipeline integrity management ("TIMP") regulatory asset balance, as approved in PSNC's prior rate case, will be fully amortized by October 31, 2021. PSNC is proposing the projected balance as of June 30, 2021, to be amortized over a 5-year period. **Per Supplemental Filing**: This adjustment update reflects actual TIMP additions through June 30, 2021, in lieu of projected additions used in the application. The proposed amortization period was updated to reflect a 4-year amortization period.

Adj #	Adjustment Amount ($)	Adjustment Narrative
3L	398,407	**To increase expenses for inflation.** This pro forma adjustment is applicable to test period O&M expenses not covered in Adjustments 3A through 3Y. An inflation factor based upon the 2021 forecasted Consumer Price Index is applied, yielding a total pro forma expense adjustment. **<u>Per Supplemental Filing</u>**: No change from the application was made.
3M	7,251,630	**To increase service company charges to the going-level basis.** This adjustment reflects the difference between the test period service company charges and the 2021 service company charges driven by higher DES service company costs in 2021. The higher costs are primarily related to a change in allocated IT related charges, contact centers, and other functional areas. **<u>Per Supplemental Filing</u>**: This adjustment update reflects annualized service company charges based on actual charges through June 30, 2021, in lieu of anticipated charges used in the application.
3N	(22,332)	**To decrease expenses for allocations to non-utility activities.** This adjustment focused on expenses that include items shared by non- regulated operations and allocates a portion of these expenses to non-utility operations. **<u>Per Supplemental Filing</u>**: No change from the application was made.

Adj #	Adjustment Amount ($)	Adjustment Narrative
3O	144,517	**To increase the cost of transportation by removing a non-recurring tax credit.** This adjustment removes a non-recurring compressed natural gas tax credit that occurred during the test period due to federal legislation. **Per Supplemental Filing**: No change from the application was made.
3P	9,234,501	**To increase the regulatory amortization expense for deferred distribution integrity management program costs.** The unamortized deferred distributions pipeline integrity management ("DIMP") regulatory asset balance, as approved in PSNC's last rate case, will be fully amortized by October 31, 2021. PSNC is proposing this balance be amortized over a 5-year period. **Per Supplemental Filing**: This adjustment update reflects actual DIMP additions through June 30, 2021, in lieu of projected additions used in the application. The proposed amortization period was updated to reflect a 4-year amortization period.
3Q	49,735	**To increase postage expenses to reflect customer growth.** This adjustment applies the actual test period postage expense per the books by the growth factor that was calculated in Adjustment 1, which results in a pro forma postage expense. **Per Supplemental Filing**: No change from the application was made.

Adj #	Adjustment Amount ($)	Adjustment Narrative
3R	(69,788)	**To decrease expenses for allocations to non-utility activities.** This entry was recorded to remove merger related costs to non-utility accounts. **Per Supplemental Filing**: No change from the application was made.
3S	3,255,293	**To increase incentive plan expense to the going-level basis.** This adjustment calculates the difference between the test period incentive expense per the books and the projected 2021 annual incentive program expense. **Per Supplemental Filing**: This adjustment update reflects actual 2021 incentive compensation through June 30, 2021, in lieu of projected incentive compensation used in the application.
3T	151,062	**To increase the fuel cost of company fleet.** This adjustment reflects an increase in the fuel cost of PSNC's fleet based on a 3- year average price per gallon. **Per Supplemental Filing**: No change from the application was made.
3U	(4,371)	**To decrease mileage expense to reflect the most recent Internal Revenue Service ("IRS") rate.** The adjustment to mileage expense was needed to reflect the most recent IRS rate for charges related to employee owned/leased vehicles. **Per Supplemental Filing**: No change from the application was made.

Adj #	Adjustment Amount ($)	Adjustment Narrative
3V	(34,140)	**To decrease costs related to the long-term disability share medical plan.** This adjustment removes a non-recurring long-term disability medical credit. **Per Supplemental Filing**: No change from the application was made.
3W	(750,000)	**To remove conservation program costs.** This adjustment removes the conservation program costs in rates due to the Company proposing a rider to recover these costs. **Per Supplemental Filing**: No change from the application was made.
3X	1,279,826	**To increase excess liability insurance expense to the going-level basis.** This adjustment reflects higher excess liability premiums, as the Company's excess liability insurance premium increased effective September 1, 2020. **Per Supplemental Filing**: No change from the application was made.
3Y	285,000	**To increase research and development expenses to the going-level basis.** PSNC is proposing to fund research and development expenses related to blending hydrogen with natural gas. This adjustment reflects the O&M portion of this research and development. The Company is actively engaged in discussions with a large energy contractor in North Carolina and a national gas trade association with experience in hydrogen research and development. **Per Supplemental Filing**: No change from the application was made.

Adj #	Adjustment Amount ($)	Adjustment Narrative
3Z	799,976	**To increase O&M costs associated with maintaining new transmission pipelines.** This adjustment reflects higher routine O&M expenses associated with maintaining the new T-30 transmission pipeline. The annual increase in O&M costs was calculated by multiplying total transmission pipeline miles by the average cost per mile. **<u>Per Supplemental Filing</u>**: This adjustment was inadvertently not included in the Company's application and therefore was included in this supplemental filing to align with transmission pipeline O&M placed in service April 15, 2021, subsequent to the application.

Q. WOULD YOU LIKE TO FURTHER EXPLAIN ANY OF THE UPDATED PRO FORMA ADJUSTMENTS IN TABLE A?

A. Yes. The update to salaries and wage expense was necessary for alignment with updated headcount. This update uses actual employee salary and wage rates as of June 30, 2021, and includes an adjustment for ten posted positions, 24 fewer positions than projected in the original application. These positions were not filled as of June 30 due to a delay in hiring driven by broader economic conditions resulting from the pandemic and an effort by the Company to attract diverse candidates. PSNC expects these positions to be filled before the hearing in this docket.

Q. PLEASE DESCRIBE THE NEW PRO FORMA ADJUSTMENT.

A. PSNC added Adjustment 3Z to reflect the ongoing operating expense of the T-30 pipeline that was placed into service in April 2021. This adjustment was inadvertently omitted from the original filing.

Q. PLEASE EXPLAIN THE UPDATES TO PRO FORMA GENERAL TAX EXPENSE REFLECTED ON PAGE 4 OF SPAULDING SUPPLEMENTAL EXHIBIT 6.

A. PSNC updated its pro forma general tax expense to correct an error in franchise taxes and to reflect June 30, 2021, actual results. Pro forma payroll tax expense was updated to align with the updated pro forma salaries and wages expense and short-term incentive plan expense adjustments shown in Table A. I updated my revenue request computation for the updated pro forma general tax expense on page 1 of Spaulding Supplemental Exhibit 6.

Q. ARE THERE ANY UPDATES TO THE EMBEDDED COST OF DEBT REFLECTED ON PAGE 2 OF SPAULDING SUPPLEMENTAL EXHIBIT 6?

A. Yes, there are two updates. The embedded cost of long-term debt was updated to incorporate the actual cost of the $150 million long-term debt refinancing that occurred in March 2021 in lieu of the estimated cost of that issuance that was included in the Company's application. This update yielded a reduction in the embedded cost of long-term debt from 4.59% to 4.48%. The embedded cost of short-term debt was updated to incorporate the actual cost rates as of June 30, 2021. This update yielded an increase in the embedded cost of short-term debt from .24% to .25%. I also updated the revenue request computation on page 1 of Spaulding Supplemental Exhibit 6.

Q. IN TOTAL, HOW DO THESE UPDATES IMPACT PSNC'S REVENUE REQUIREMENT IN THIS PROCEEDING?

A. The updated impact on the proposed revenue requirement, which is shown on page 1 of Spaulding Supplemental Exhibit 6, totals $49,664,720.

Q. PLEASE DESCRIBE THE UPDATED LEAD LAG STUDY IN SPAULDING SUPPLEMENTAL EXHIBIT 8.

A. Spaulding Supplemental Exhibit 8 corrects errors in certain calculations in the lead lag study filed with the original application. The lead lag study was also updated to reflect the impact on working capital from the other updates in the supplemental filing set forth on page 1 of Spaulding Supplemental Exhibit 6.

Q. DOES THE COMPANY HAVE AN UPDATE ON ITS PROPOSED ACCOUNTING TREATMENT FOR THE HYDROGEN RESEARCH AND DEVELOPMENT PROJECT?

A. Yes. As discussed in Company witness Randall's direct testimony, PSNC is requesting Commission approval of the accounting treatment for the capital investment related to its research and development initiative. The Company is actively engaged in encouraging discussions with a large contractor located in North Carolina, and also with a national gas trade association with experience in hydrogen research and development. PSNC plans to engage these entities in the development of the hydrogen project, which will be managed by Company personnel. As it relates to Adjustment 8 shown on page 4 of Spaulding Supplemental Exhibit 6, PSNC has not yet invested the $215,000 in capital equipment so this amount was not included in the supplemental filing. However, since this project is a proposed research and development project, and has not been placed in plant in service, the Company renews its request for the Commission to approve the Company's proposed research and development investment, whereby this capital project would be included in rate base when it is later placed in service.

Q. DOES THIS COMPLETE YOUR SUPPLEMENTAL TESTIMONY?

A. Yes, however, I reserve the right to supplement or amend my testimony before or during the Commission's hearing.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

REBUTTAL TESTIMONY

OF

JAMES A. SPAULDING

OCTOBER 7, 2021

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

A. My name is James A. Spaulding. My business address is 800 Gaston Road, Gastonia, North Carolina 28056. I am employed by Dominion Energy Services, Inc. ("DESI"), a subsidiary of Dominion Energy, Inc. ("DEI"), as Manager – Financial & Business Services for Public Service Company of North Carolina, Inc., doing business as Dominion Energy North Carolina ("PSNC" or the "Company").

Q. ARE YOU THE SAME JAMES A. SPAULDING WHO PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

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

A. The purpose of my rebuttal testimony is to respond to certain accounting adjustments proposed by the Public Staff. Specifically, I will address adjustments proposed by Public Staff witnesses Neha R. Patel, Lynn L. Feasel, Julie G. Perry, Mary A. Coleman, and Sonja R. Johnson.

Q. DO YOU AGREE WITH WITNESS PATEL'S CALCULATION OF OTHER OPERATING REVENUES?

A. No. Ms. Patel used a three-year average (2018, 2019, and 2020) to determine other operating revenues. The Company contends that it was not appropriate to include 2018 and 2019 in the calculation because these years do not reflect the ongoing impacts of the COVID-19 State of Emergency moratoriums. North Carolina has now been under a State of Emergency for 19 months, beginning

March 2020. The Governor chose not to rescind the State of Emergency in the most recent Executive Order issued September 24, 2021. As such, the Company continues to be unable to recognize late payment fees and it is not reasonable to predict this situation returning to a normalized level in the near future.

Q. DO YOU AGREE WITH WITNESS PATEL'S ADJUSTMENTS RELATED TO FIXED GAS COSTS?

A. Not completely. Witness Patel incorrectly reflected a three-year average for secondary market credits through a reduction in fixed gas costs when secondary market credits should be addressed in the All-Customers deferred account. Witness Patel also incorrectly calculated the step rates for Rates 125, 127, and 140. It appears that the secondary market credit issue has been corrected in Public Staff witness Johnson's Revised Exhibit 1. However, the step rate issue has not been corrected.

Q. DO YOU AGREE WITH WITNESS FEASEL'S ADJUSTMENT RELATED TO DEFERRED DISTRIBUTION INTEGRITY MANAGEMENT PROGRAM ("DIMP") COSTS?

A. No. Witness Feasel removes what she characterizes as "non-eligible" deferred DIMP expenses. Ms. Feasel's workpapers indicate that she considers these "non-eligible" expenses to be June 2021 accruals. However, these accruals are accurately reflected and are appropriately included in DIMP expenses eligible for recovery in this proceeding.

Q. DO YOU HAVE ANY OTHER DISAGREEMENTS WITH WITNESS FEASEL'S TESTIMONY?

A. Yes. Ms. Feasel recommends a five-year amortization of Transmission Integrity Management Program and DIMP expenses. The Company believes a four-year amortization period is more appropriate as it allows the Company to recover its costs in a timelier manner.

Q. DOES THE COMPANY AGREE WITH WITNESS COLEMAN'S ADJUSTMENT RELATED TO EXECUTIVE COMPENSATION?

A. No, the Company disagrees with the adjustment as discussed in the rebuttal testimony of Company witness Regina J. Elbert.

Q. DO YOU AGREE WITH WITNESS PERRY'S ADJUSTMENTS RELATED TO THE DURHAM INCIDENT?

A. No, I do not. Ms. Perry correctly recognizes that there has been no report of any wrongdoing on PSNC's part from the April 10, 2019 Durham incident and that PSNC has incurred substantial legal bills related to pending litigation initiated by numerous parties in multiple lawsuits. However, she considers the Durham incident to be an extraordinary, non-recurring event and has removed the legal fees incurred in 2020 from the Company's cost of service. The Company does not agree. I understand that PSNC has already been named as a defendant in nineteen lawsuits, involving nearly thirty plaintiffs, currently pending in Durham County Superior Court. More lawsuits are anticipated as the statute of limitations has not expired. I further understand that these cases are in the most preliminary stages and will continue to require this level of legal fees for many years. Depositions of myriad individuals will be taken, including of the plaintiffs, several co-defendants, and experts for each party. Written discovery will continue to be served; motions will be filed and argued; and trials and settlements are likely to occur. At present, it is anticipated that any trials of these lawsuits would occur through 2023. Any appeals of litigated cases would take years to be decided. The lack of report of wrongdoing does not obviate PSNC's duty to participate fully in the legal process. Ms. Perry's adjustment would prevent the Company from recovering these costs that the Company must incur for many years to defend itself from these and potentially other lawsuits.

Ms. Perry also contends that excess insurance policies may cover these types of legal expenses once all the litigation is resolved. While there is a possibility that the Company may eventually recover some expenses once litigation is resolved, any recovery is speculative and many years away.

Q. SHOULD THE COMMISSION CHOOSE TO NOT INCLUDE THE LEGAL EXPENSES RELATED TO THE DURHAM INCIDENT IN BASE RATES, DOES THE COMPANY HAVE AN ALTERNATIVE PROPOSAL?

A. Yes. Absent alternative ratemaking treatment, the Company would not be able to recover costs that it is certain to incur. As an alternative, the Company would propose deferred accounting treatment for all legal costs related to the Durham incident. If the deferred accounting treatment is granted, these accumulated costs would be deferred until the Company's next general rate case.

Q. PLEASE DISCUSS THE ADJUSTMENTS PROPOSED BY WITNESS JOHNSON.

A On page 8 of witness Johnson's testimony, she lists her accounting and ratemaking adjustments. The Company disagrees with several of her adjustments, and I will address certain of witness Johnson's adjustments in order below. However, I note that my silence in response to other adjustments should not be construed as my agreement with them.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO DEPRECIATION?

A. No, I do not. Witness Johnson has reduced depreciation expense by $4,210,307 based on the recommendations of Public Staff witness McCullar. For the reasons set forth in PSNC witness Spanos's rebuttal testimony, the Company disagrees with this adjustment.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO THE COMPANY'S INCENTIVE PLANS?

A. No, I do not, for the reasons set forth in the rebuttal testimony of Company witness Regina J. Elbert.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO THE COMPANY'S RATE CASE EXPENSES?

A. No. PSNC's level of rate case expenses is based on actual experience and estimates from outside consultants. The Public Staff's estimate, on the other hand, included only year-to-date charges through June 30, 2021, and then the Public Staff arbitrarily decreased the expenses by $168,979, which would not allow the Company to recover its projected rate case costs in this proceeding. The Company also recommends that these expenses be amortized over three years, as opposed to the Public Staff's recommendation of five years, to allow timelier recovery.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO THE COMPANY'S UNCOLLECTIBLES EXPENSE?

A. No, the Company disagrees with witness Johnson's treatment of uncollectibles expense. She appropriately removed the cost of gas from the write-off (the numerator) portion of the calculation but failed to remove the cost of gas from the revenue component (the denominator). The cost of gas should be removed from both parts of the equation. I am also recommending a 3-year average rather than a 5-year average, consistent with long standing practice. Using older data makes the resulting uncollectibles percentage less representative of the going level. Additionally, I excluded 2020 expenses because 2020 was an outlier due to the effects of the pandemic, such as economic volatility, the disconnection moratorium, and the Governor's State of Emergency. Finally, when commodity prices are higher (the closing price at Henry Hub was $5.54 per dekatherm on October 1, 2021), PSNC's customers' ability to pay is affected and the likelihood of write-offs is greatly increased.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO THE COMPANY'S ADVERTISING EXPENSES?

A. No, the Company disagrees with the Public Staff's characterization of certain advertising as promotional rather than informational. Additionally, the Public

Staff has excluded costs associated with the Company's mobile app, which serves a useful purpose in the provision of natural gas service in that almost 50% of the Company's customers use the mobile app. It is a useful tool for providing customer billing and usage information and should not be disallowed. The Public Staff also applied an arbitrary percentage to disallow other various advertising invoices.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO THE COMPANY'S LOBBYING EXPENSES?

A. No, the Public Staff arbitrarily excluded as lobbying expenses certain labor costs of internal affairs employees who are not registered lobbyists. These employees perform many hours of duties associated with communications or activities as part of a business, civic, religious, fraternal, or commercial relationship which is not connected to legislative or executive action, or both. Expenses in connection with these activities were appropriately recorded above-the-line. These employees follow Company procedures and, for example, record any hours associated with time spent attending town and city hall meetings below-the-line, despite the fact that this time involves an above-the-line activity.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO THE COMPANY'S SPONSORSHIP EXPENSES?

A. No, the Public Staff incorrectly disallowed a portion of industry association dues and sponsorships that the Company already had included below-the-line in FERC Account 426. Additionally, the Public Staff disallowed some industry association dues and sponsorships that result in benefits to customers and which were recorded above-the-line. For example, the 811 Annual Membership fee was disallowed. PSNC's participation in this important safety-focused organization is critical to assist in the prevention of third-party damage.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO THE COMPANY'S INFLATION EXPENSES?

A. The Company disagrees with Public Staff witness Johnson's inflation adjustment to the extent it is applied to other adjustments to which the Company does not agree.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO THE COMPANY'S NON-UTILITY EXPENSES?

A. No. The Public Staff adjustment incorrectly assumes that the Company has not appropriately allocated the costs to non-utility accounts. The adjustment Ms. Johnson recommends should be rejected because the Company already allocates an appropriate portion of these operating costs to non-utility accounts through its normal accounting practices.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO SERVICE COMPANY EXPENSES?

A. No. The Public Staff estimated the Company's going level of Dominion Energy Services, Inc. ("DES") expense by using a 12-month ended June 30, 2021. In the test year, PSNC received a partial allocation of costs from DES due to the fact that PSNC did not transition its accounting system from PeopleSoft to SAP until January 2021. In 2021, however, PSNC will receive a full allocation of

DES costs. Therefore, the Company's methodology of establishing an ongoing level of DES costs is based on more recent experience and is more accurate than Ms. Coleman's recommended level, which includes a six-month period when PSNC was not charged a full allocation of DES costs.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO THE COMPANY'S SEVERANCE EXPENSES REGARDING RETIREMENTS?

A. No. The Company recorded all severance costs related to retirements below-the-line and no further adjustment is appropriate.

Q. DO YOU AGREE WITH WITNESS JOHNSON'S ADJUSTMENT RELATED TO THE COMPANY'S CNG TAX CREDIT EXPENSES?

A. No, witness Johnson reversed the Company's CNG Tax Credit adjustment. The current CNG Tax Credit expires on December 31, 2021, absent congressional action to renew the credit. Neither PSNC nor the Public Staff can predict if, or when, the CNG Tax Credit might get renewed. Therefore, the Company's adjustment to the CNG Tax Credit is appropriate. Moreover, consistent with prior practice, if the CNG Tax Credit is renewed, PSNC will thereafter reflect this credit in the price charged to PSNC's CNG customers.

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. They include, but are not limited to, the following: depreciation and accumulated depreciation, property tax expense, payroll tax expense, the regulatory fee, and all components of rate base.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, however, I reserve the right to supplement or amend my testimony before or during the Commission's hearing.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

SETTLEMENT TESTIMONY

OF

JAMES A. SPAULDING

OCTOBER 15, 2021

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

A. My name is James A. Spaulding. My business address is 800 Gaston Road, Gastonia, North Carolina 28056. I am employed by Dominion Energy Services, Inc., a subsidiary of Dominion Energy, Inc. ("DEI"), as Manager – Financial & Business Services for Public Service Company of North Carolina, Inc., doing business as Dominion Energy North Carolina ("PSNC" or the "Company").

Q. ARE YOU THE SAME JAMES A. SPAULDING WHO PROVIDED DIRECT, SUPPLEMENTAL, AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes.

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

A. The purpose of my settlement testimony is to explain economic adjustments to the Company's application as reflected in the Stipulation of Settlement ("Stipulation") between PSNC, the Public Staff-North Carolina Utilities Commission, Carolina Utility Customers Association, Inc., and Evergreen Packaging, LLC (collectively, the "Stipulating Parties").

Q. PLEASE DISCUSS THE ADJUSTMENTS TO PSNC'S REVENUE REQUIREMENT AS AGREED TO IN THE STIPULATION.

A. Exhibit A to the Stipulation shows the adjustments agreed to by the Stipulating Parties to the revenue requirement proposed in the Company's supplemental testimony and exhibits filed on August 10, 2021, which reflected updates as of June 30, 2021. The adjustments included:

- Capital Structure and Cost of Capital: The Stipulating Parties agreed that the appropriate capital structure for use in this proceeding consists of 51.60% common equity, 47.06% long-term debt, and 1.34% short-term debt. The agreed cost of long-term debt is 4.48% and the agreed cost of short-term debt is 0.25%. The agreed return on common equity appropriate for use in this proceeding is 9.60%.
- Fixed Gas Costs Apportionment Percentages: The Stipulating Parties agreed that it is appropriate to use the fixed gas costs apportionment percentages presented in Exhibit D to the Stipulation.
- Customer Usage Tracker Factors: The Stipulating Parties agreed that it is appropriate to utilize the "R" values, heat load factors, and base load factors as set forth in Exhibit E to the Stipulation.
- Depreciation: The Stipulating Parties agreed that effective November 1, 2021, PSNC will adopt the depreciation rates reflected in the depreciation study filed with and supported by the testimony of Company witness John J. Spanos.
- Amortization of Deferred Assets: The Stipulating Parties agreed that it is appropriate to amortize and allow recovery of $67,903,061, in deferred transmission integrity management program operations and maintenance ("O&M") costs, which reflect actual deferred expenses through June 30, 2021, net of regulatory amortizations through October 31, 2021, over a four-year period beginning with the effective date of rates in this proceeding. For deferred distribution integrity management

O&M costs, the Stipulating Parties agreed that it is appropriate to amortize and allow recovery of $38,116,252, which reflects actual deferred expenses through June 30, 2021, net of regulatory amortizations through October 31, 2021, over a four-year period beginning with the effective date of rates in this proceeding.

- Employee Compensation: The Stipulating Parties agreed to reduce the DEI Board of Directors expenses allocated to PSNC. The Stipulating Parties also agreed to downward adjustments for payroll, pension and other benefits, employee benefits, executive compensation, and incentives.
- Rate Case Expenses: The Stipulating Parties agreed that for purposes of this proceeding, it is appropriate to use an updated rate case expense and agreed to a reduction of rate case expense, which the Stipulating Parties further agreed should be amortized and collected over a three-year period beginning with the effective date of rates in this proceeding.
- Uncollectibles: The Stipulating Parties agreed that the revenue requirement presented in the Stipulation reflects a downward adjustment in the amount of non-gas cost uncollectibles expense after applying the non-gas cost uncollectibles ratio to the pro forma revenues, which results in an increase to O&M expenses. The Stipulating Parties also agree to reflect the non-gas cost uncollectibles ratio of 0.1532% in the revenue requirement retention factor used to compute the amount of the rate increase.

- Other Operating Revenues: The Stipulating Parties agreed to use in the cost of service computation an increased level of pro forma other operating revenues.
- Non-Utility Adjustment: The Stipulating Parties agreed upon an adjustment attributable to non-utility operations.
- Miscellaneous Expense Adjustments: The Stipulating Parties agreed to downward adjustments to the following additional areas of PSNC's O&M expenses: Advertising; Lobbying; Service Company Costs; Sponsorships and Donations; Inflation; Research and Development Costs; Special Contracts Adjustment; and Interest on Customer Deposits.

Q. WHAT DID THE STIPULATING PARTIES AGREE TO REGARDING THE COMPANY'S LEGAL FEES FOR THE 2019 DURHAM INCIDENT?

A. The Stipulating Parties agreed to defer for recovery in the Company's next general rate case legal expenses incurred on or after January 1, 2020, relating to the 2019 Durham incident, offset by any insurance proceeds related to the incident.

Q. ARE THE ADJUSTMENTS TO REVENUES AND RATES PROPOSED IN THE STIPULATION FAIR, JUST, AND REASONABLE?

A. Yes. 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 significantly lower in comparison to PSNC's proposed rates in this proceeding.

Q. DOES THIS CONCLUDE YOUR SETTLEMENT TESTIMONY?

A. Yes, it does.

COMMISSIONER BROWN-BLAND: All right. And now the witness is ready for cross?

MS. GRIGG: Yes, ma'am.

COMMISSIONER BROWN-BLAND: Is there cross-examination for this witness?

MS. HOLT: No cross.

COMMISSIONER BROWN-BLAND: All right. There being no cross -- I hear no one piping up -- we'll move on to Commissioners' questions.

Are there questions from the Commission?

CHAIR MITCHELL: Commissioner Brown-Bland, I do have a few questions for the witness, if I may.

COMMISSIONER BROWN-BLAND: Chair Mitchell, you're recognized. Go ahead.

CHAIR MITCHELL: All right. Thank you.

EXAMINATION BY CHAIR MITCHELL:

Q. Good morning, Mr. Spaulding. We have a few questions for you pertaining to your testimony related to AFUDC, specifically referring to Pages 18 through I think about 21 of your direct testimony, if it helps you to have that in front of you.

A. I have that.

Q. Okay. Perfect. I have a series of questions for you that I can ask, but I'm going to start with sort of a general one.

Can you walk us through -- just explain to us the -- the issue here, why you raise it in your testimony and what the issue is? And I'll -- I'll start with that. So just kind of at a high level, walk us through the issue.

A. I have to familiarize myself. I think we're talking about the -- the income tax result from capitalizing AFUDC, or is there something more specific you --

Q. That's correct. I mean, we're specifically -- we're -- I -- help me get grounded in what the issue is. Why did you -- why did you raise this in your testimony and what specifically are you saying in your testimony?

A. The company's requesting recovery of -- of a regulatory asset associated with AFUDC.

Q. Okay. So you -- you -- so I'll -- I'll just -- I'll walk -- I'll walk through my questions.

All right. Page 20 of your direct testimony, you state that the company's requesting recovery of the regulatory asset of approximately thirteen -- 13.3 million --

A. Yes.

Q. -- which represents under-recovered AFUDC equity balance recorded on PSNC's books as of December 31, 2020.

That's correct, correct? Is that -- is that

correct?
A. That is correct.
Q. Okay. So just -- first question for you, why is there under -- why is there an under-recovery of AFUDC equity balance?
A. I'm just looking over my testimony here.
(Witness examines document.) I -- I think it has to do with the -- the tax treatment. It's a -- some imbalances there, but I -- I think what we essentially should have been doing was -- was grossing that up for income taxes.
Q. Okay. So is -- is it your testimony that the company wasn't grossing -- wasn't grossing it up; therefore, there's an underrecovery?
A. That is my understanding. Let me just kind of look back over it and make sure I haven't misstated something.
Q. Okay.
A. (Witness examines document.) Sorry. Can you repeat the question just to make sure I'm -- I'm answering your question?
Q. Yes. My question was why is there -- why -- in general, my question is why is there an underrecovery. And I think I heard you say because you -- the company hadn't

been grossing up. And I'm just asking that you confirm that that is your testimony.
A. That is my testimony, yes.
Q. Okay. All right. You also state on Page 20 that the company is not requesting a retroactive recovery of all the previously accrued AFUDC equity, but that the balance in the account represents just the revenue -- the cumulative revenue shortfall related to the equity component of AFUDC.
When did -- tell us when this accumulation began.
A. I don't think I know the answer to that question.
Q. Okay. So it -- could it have been a one-year accumulation or is this an accumulation over another period -- multiple years?
I mean, I hear you saying you don't know the answer to the question, but can you -- can you ballpark it for us?
A. We -- we -- we'd be happy to file a late-filed exhibit. I'm -- I'm assuming this goes back to at least the last rate case, but we -- we'd be happy to file a late-filed exhibit.
Q. Okay. Please do that. We'd like to know the -- the time horizon associated with the accumulation. So in the late-filed exhibit, include -- please include that information.

Continuing on, Mr. Spaulding, did PSNC recently make changes to its AFUDC accounting which necessitated or prompted this request?

A. No. I'm -- I'm not aware of any change in accounting. This was just recognized that this was, I believe, an oversight on our part, subject to check.

Q. Okay. And -- and you-all addressed this issue in Paragraph 6(g) of the Stipulation; is that correct?

A. When you say 6(g), I'm going to flip over to the Stipulation.

Q. And it -- and that doesn't even really matter. I mean, I -- I'm just -- you -- you addressed this with the Public Staff in the Stipulation; is that --

A. That -- that's correct, yes.

Q. Okay. And in the Stipulation, you-all agreed that the equity AFUDC regulatory asset and its equal and offsetting EDIT liabilities will both be included in rate base; is that -- is that correct?

A. That is correct.

Q. Okay. So will you confirm for me that both the asset and the offsetting liability are included in rate base, that the net amount in rate base is actually zero?

A. That appears to be correct. If -- I -- I don't know the exact nuances of that. That's tax policy. But, yeah, we are seeking recovery.

Q. Okay. Okay. And so does this mean that this treatment has no impact on the total revenue requirement being established in this proceeding?

A. I -- I'll be happy to file a late-filed exhibit. I'll double-check with our tax -- tax department to make sure. I just don't want to give you bad information.

Q. Okay. Well, I'd ask that in the late-filed exhibit that question be answered as well. And also --

A. Just to -- just to clarify, how -- how that affects the revenue requirement?

Q. That's right. I mean, we -- I want to know what the impact here is to the revenue requirement and, therefore, to customers, you know, of the -- of the agreement set forth in the Stipulation. I'll also ask the Public Staff these same questions. Heads up to the Public Staff.

But -- so in the late-filed exhibit, if you could -- you could address the time horizon of the accumulation and confirm that recording both the -- or including both the asset and the liability have no impact on revenue requirement and, therefore, on customer rates.

I see Ms. Grigg is writing that down, but just give me a signal that you've got those questions.

A. I got those questions, yes.
Q. Okay.
MS. GRIGG: We have them. Thank you.
BY CHAIR MITCHELL:
Q. All right. Let's see. All right. That's all for me, Mr. Spaulding. Thank you.
A. Thank you.
COMMISSIONER BROWN-BLAND: All right. Any other Commissioner have questions for witness Spaulding?
(No response.)
COMMISSIONER BROWN-BLAND: I can't see everybody at one time right now. So when I don't hear anybody, I'm -- I'm going to move on.
EXAMINATION BY COMMISSIONER BROWN-BLAND:
Q. I did have one question for you, Mr. Spaulding.
A. Yes.
Q. This relates to the Conservation Program. It's my understanding that once settlement was reached and it was agreed upon that there would be a rider to recover the Conservation Program costs, the $750,000 that had been attributed to the program had been removed from the test year expenses. I believe that's your Direct Exhibit 6, Page 3 of 5.
Does that sound correct?

A. That does sound correct.

Q. All right. And then in the company's filing in Docket Number G-5, Sub 495A, which was on the -- the annual report for the Conservation Program, the costs incurred there was $795,369.

I'm just wondering if -- if there's a reason you could explain why in this proceeding we're only removing 750,000. Do those numbers square up?

A. Subject to check, it's my understanding that the 750,000 is basically the revenue requirement, and so we're removing that revenue requirement and replacing it with a rider. Witness Hinson may be able to speak to that additionally, but that's my understanding.

Q. All right. Very well.

COMMISSIONER BROWN-BLAND: All right. Is there questions on Commission's questions? Ms. Grigg?

MS. GRIGG: No, ma'am.

COMMISSIONER BROWN-BLAND: All right.

MS. HOLT: No questions.

COMMISSIONER BROWN-BLAND: All right. I hear no one speaking up saying that they have questions. And so, Ms. Grigg, back to you.

MS. GRIGG: Yes, ma'am. Thank you. Now, at this more appropriate time, I move that Mr. Spaulding's seven (7) direct exhibits and eight (8) supplemental exhibits be moved into evidence.

COMMISSIONER BROWN-BLAND: That motion is allowed and a total of 15 exhibits will be received into evidence.

(Spaulding Direct Exhibits 1 through 7 and Spaulding Supplemental Exhibits 1 through 8 were received into evidence.)

COMMISSIONER BROWN-BLAND: All right. Mr. Spaulding, I believe now you may be excused.

MS. GRIGG: PSNC will now call -- thank you, ma'am. PSNC will now call Mr. Byron W. Hinson to the stand.

COMMISSIONER BROWN-BLAND: All right. There's Mr. Hinson.

(WHEREUPON,

BYRON W. HINSON,

having been duly affirmed, testified as follows:)

COMMISSIONER BROWN-BLAND: All right. Ms. Grigg, your witness.

MS. GRIGG: Thank you.

DIRECT EXAMINATION BY MS. GRIGG:

Q. Good morning, Mr. Hinson.

A. Good morning.

Q. Would you please state your name and business address for the record?

A. My name is Byron W. Hinson. My business address is 400 Otarre Parkway, Cayce, South Carolina.

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

A. I'm employed by Dominion Energy Services as the Director of Regulation for PSNC.

Q. Did you cause to be prefiled in these dockets on April 1st, 2021, 18 pages of direct testimony and 11 exhibits?

A. I did.

Q. Do you have any changes or corrections to your direct testimony or exhibits?

A. I do not.

Q. If I were to ask you the same questions that appear in your direct testimony today, would your answers be the same?

A. They would.

Q. Mr. Hinson, did you also cause to be prefiled in these docket on August 10th, 2021, eight (8) pages of supplemental testimony and seven (7) exhibits?

A. I did.

Q. Do you have any changes or corrections to your supplemental testimony or exhibits?

A. I do not.

Q. If I were to ask you the same questions that appear in your supplemental testimony today, would your answers be the same?

A. Yes, they would.

Q. Mr. Hinson, did you also cause to be prefiled on these -- in these dockets on October 7th, 2021, eight (8) pages of rebuttal testimony?

A. I did.

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

A. I do not.

Q. If I were to ask you the same questions that appear in your rebuttal testimony today, would your answers be the same?

A. Yes, they would.

Q. Finally, Mr. Hinson, did you also cause to be prefiled in these dockets on October 15th, 2021, five (5) pages of settlement testimony?

A. I did.

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

A. I do not.

Q. If I were to ask you the same questions that appear in your settlement testimony today, would your answers be the same?

A. Yes, they would.

Q. Mr. Hinson, did you prepare a summary of your testimonies?

A. I did.

Q. Would you please present your summary to the Commission?

A. Be happy to. Last week, PSNC reached a Stipulation of Settlement with the Public Staff, Carolina Utilities Customers Association, Inc., and Evergreen Packaging, LLC, resolving all the issues in this proceeding.

On October 15th, I filed testimony supporting the Stipulation and explaining the customer impact of PSNC's rate case. The revenue requirement the company filed with this application was reduced through the settlement process with the stipulating parties. Specifically, the Stipulation results in an overall customer increase of approximately 5.12 percent before the benefit of the excess deferred income tax flowback. The net of the increase is just slightly more than half the rate of inflation of 8.97 since the company's last general rate proceeding in 2016.

If the Stipulation is approved, the average residential customer's bill would increase by less than one dollar per month in Year 1. In summary, the Stipulation is a product of give-and-take negotiations among the stipulating parties and is just and reasonable and should be approved by the Commission.

Q. Thank you, sir.

MS. GRIGG: Commissioner Brown-Bland, at this time, I move that the prefiled direct, supplemental, rebuttal and settlement testimonies of Mr. Hinson be copied into the record as if given orally from the stand and that his 11 direct exhibits and seven (7) supplemental exhibits be marked for identification as prefiled.

COMMISSIONER BROWN-BLAND: All right. That motion is allowed.

(Hinson Direct Exhibits 1 through 11 and Hinson Supplemental Exhibits 1 through 7 were marked for identification.)

(Whereupon, the prefiled direct, prefiled supplemental, prefiled rebuttal and prefiled settlement testimonies of Byron W. Hinson were copied into the record as if given from the stand.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632

DIRECT TESTIMONY

OF

BYRON W. HINSON

APRIL 1, 2021

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

A. My name is Byron W. Hinson. My business address is 400 Otarre Parkway, Cayce, South Carolina 29033. I am employed by Dominion Energy Services, Inc., as Director – Regulation for Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND, WORK EXPERIENCE, AND OTHER QUALIFICATIONS.

A. I graduated from the University of South Carolina in 1991 with a Bachelor of Science degree in Finance. Following graduation, I worked as an analyst with SCANA Corporation ("SCANA"). Over the years, I have held positions of increasing responsibility in various areas, including corporate planning, corporate finance, financial services, investor relations, and rates and regulatory. In 2010, I was promoted to Director of Financial Planning and Investor Relations. In 2014, I became Director of Rates and Regulatory at South Carolina Electric & Gas Company, and in 2019, I assumed my current position with the Company.

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

A. I testify in support of PSNC's application in this docket. Specifically, the purpose of my testimony is to explain and support:

(1) PSNC's compliance with NCUC Form G-1 Minimum Filing Requirements;

(2) The revenue requirement requested in this proceeding;

(3) The impact of PSNC's request on customers;

(4) The cost of service study supporting the proposed rate design;

(5) The Company's proposed rate design;

(6) The Company's proposed plans for flowing through the benefits resulting from excess deferred income taxes ("EDIT") associated with the federal Tax Cuts and Jobs Act of 2017 ("TCJA") and state income tax rate reductions addressed in Docket No. M-100, Sub 148, through rate riders;

(7) The proposed changes to PSNC's tariff;

(8) Factors to be used in the Company's Customer Usage Tracker – Rider C adjustment mechanism ("CUT");

(9) The Company's conservation programs and establishment of a Conservation Program Tracker – Rider F, and deferred accounting associated with the programs;

(10) The Company's proposed GreenTherm™ Renewable Natural Gas Program ("GreenTherm™ Program") and establishment of deferred accounting associated with the program.

Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. Hinson Direct Exhibits 1 through 11 were prepared by me or under my direction and supervision.

Q. HAS PSNC COMPLIED WITH COMMISSION RULE R1-17(b)(12)(c) IN THIS PROCEEDING BY FILING THE INFORMATION REQUIRED BY NCUC FORM G-1?

A. Yes. PSNC's Form G-1 was prepared and filed with its application and supporting testimony in this proceeding.

Q. WHAT IS PSNC'S REVENUE REQUEST IN THIS PROCEEDING?

A. As is reflected on Hinson Direct Exhibit 1, PSNC is requesting approval of an annual revenue increase of $53.1 million in this proceeding. The per-books adjustments, after the update to recognize known and measurable plant investment in the Company's revenue and expense levels as of June 30, 2021, result in an overall return of 5.32% under current rates. The proposed rates result in an overall rate of return of 7.64%.

PSNC's revenue request in this proceeding represents a 9.26% increase from current effective revenues. This increase is partially offset by a 1.99% reduction in revenues due to the proposed flow-through of EDIT resulting from changes in the federal corporate income tax rates from 35% to 21% established under the TCJA as well as state income tax reductions. PSNC proposes to address the impacts of the TCJA and state income tax reductions through riders as discussed in my testimony and fully explained in Company witness Spaulding's testimony.

Q. WHAT WILL BE THE IMPACT OF THE REQUESTED RATE INCREASE ON PSNC'S CUSTOMERS?

A. This is an overall increase of approximately 7.27%, after the TCJA and state tax reductions, which is less than the rate of inflation of 8.97% since the Company's last general rate case proceeding in 2016. If PSNC's revenue request is granted, after the income tax offsets, the average residential customer's bill would increase by approximately $4 per month. Table A summarizes the proposed revenue requirement and the effect of the proposed EDIT flow through.

Table A

	Proposed Amounts	Increase from Current Revenues
Revenue Requirement	$53,145,476	9.26%
EDIT Flow Through (Year 1)	($11,426,299)	(1.99%)
Net Impact	$41,719,177	7.27%

Q. PLEASE DISCUSS THE CHANGE IN PSNC'S RATE BASE SINCE ITS LAST GENERAL RATE CASE.

A. PSNC's last general rate case reflected a test period ending December 31, 2015, updated for known and measurable changes through June 30, 2016. The amount of PSNC's rate base in that proceeding was $946.7 million, compared to $1,748.2 million at the end of the current test period of December 31, 2020, updated for known and measurable changes through June 30, 2021. Utility plant in service, which is the largest component of rate base, grew by almost $1.2 billion over this period, most significantly in the transmission plant asset category. Table B describes the major categories of growth in plant by category.

Table B

Plant Asset Category ($ Thousands)	Test Period, With Adjustment, As of June 30, 2016	Test Period, With Adjustment, As of June 30, 2021
General Plant	$112,507	$124,634
Transmission Plant	$347,656	$1,010,294
Distribution Plant	$1,392,916	$1,901,359
Total Utility Plant	$1,853,079	$3,036,287

Q. WHAT FACTORS HAVE CONTRIBUTED TO PSNC'S INCREASE IN RATE BASE SINCE ITS LAST RATE CASE?

A. PSNC's increase in rate base is the result of several factors. First, as described in Company witness Harris's testimony, PSNC's territory has experienced significant customer growth and PSNC has made the capital investments necessary to accommodate that growth. Second, as described in Company witness Randall's testimony, PSNC constructed the T-30 pipeline to ensure reliable service to the growing Raleigh area. Third, Company witness Randall also testifies to the Company's compliance with federal pipeline safety and integrity regulations promulgated by the Pipeline and Hazardous Materials Safety Administration, and much of that compliance work has involved capital projects. A significant portion of this capital investment has already been included in the Integrity Management Tracker ("IMT") mechanism. The IMT allows the Company to recover the revenue requirement for integrity management investment closed to plant until the filing of its next general rate case.

Q. PLEASE DISCUSS THE COMPANY'S PROPOSAL TO INCLUDE THE INTEGRITY MANAGEMENT REVENUE REQUIREMENT IN BASE RATES.

A. Pursuant to Rider E the Company has included in base rates the revenue requirement associated with integrity management capital investment as of December 31, 2020.

Company witness Spaulding also proposes a pro forma adjustment to include in rate base the IMT plant projected to be installed between January 1, 2021 and June 30, 2021. When the Company updates its filing as of June 30, 2021, PSNC proposes to remove this pro forma adjustment and then include the actual amount of IMT plant in service in its rate base. Rates pursuant to the IMT bi-annual adjustment, based on the January 2021 through June 2021 actual plant in service, will become effective with the IMT increment on September 1, 2021, if granted. The Company proposes to move the increment effective as of September 1, 2021, into base rates, effective with the Commission's order in this proceeding.

Q. PLEASE DISCUSS THE PROPOSED ADJUSTMENTS TO TEST PERIOD REVENUES AND QUANTITIES OF GAS SOLD AND TRANSPORTED.

A. PSNC adjusted test period sales and transportation volumes to reflect normal weather and to reflect customer growth. Adjusted volumes were then priced at the current tariff rates, exclusive of the current temporary CUT increments and decrements and IMT increments and decrements. These adjustments are set forth in Hinson Direct Exhibit 2. Detailed workpapers supporting the adjustments are contained in Item 4 of Form G-1.

Q. PLEASE DISCUSS YOUR ADJUSTMENT TO TEST PERIOD VOLUMES TO REFLECT NORMAL WEATHER.

A. Test period sales for residential and general service customers were adjusted using 15-year normalized weather, which is the Company's standard method of normalizing volumes. The adjustments were made by using a heat sensitivity factor ("HSF") for each customer class determined through statistical regression analysis. The HSF equals the change in usage per customer for a change of one heating degree-day using a base temperature of 65 degrees Fahrenheit. New base load and HSFs for the CUT are included in Hinson Direct Exhibit 3.

Q. PLEASE DISCUSS HOW THE TEST PERIOD VOLUMES WERE ADJUSTED FOR CUSTOMER GROWTH.

A. Based on average customer growth in 2018 and 2019, test period volumes for residential customers on Rate Schedule No. 101 Residential Service were adjusted to reflect a growth rate of 2.60% and residential customers on Rate Schedule No. 102 High Efficiency Residential Service were adjusted to reflect a growth rate of 9.62%. A growth rate was not applied to Rate Schedule No. 125 Small General Service, Rate Schedule No. 127 High Efficiency Small General Service, or Rate Schedule No. 140 Medium General Service, as the number of customers did not materially change.

Q. WHY DID THE COMPANY NOT INCLUDE 2020 VOLUMES TO DETERMINE AVERAGE CUSTOMER GROWTH?

A. Customer growth in 2020 was abnormally high due to the disconnect moratorium in place for most of the year. Therefore, the Company used 2018 and 2019 data as more indicative of actual customer growth.

Q. PLEASE DISCUSS PSNC'S PROPOSED ADJUSTMENTS TO TEST PERIOD COST OF GAS.

A. The determination of adjusted cost of gas is set forth in Hinson Direct Exhibit 4. Fixed transportation and storage charges were priced at current tariff rates. The commodity cost of gas was determined by applying the current commodity cost of gas of $0.250 per therm to the adjusted sales volumes on Hinson Direct Exhibit 2. Company Use and Lost and Unaccounted For ("LAUF") volumes were also priced at $0.250 per therm. The LAUF volumes reflect losses of 70.59 dekatherms per heating degree-day and a non-weather sensitive loss level of 29,020 dekatherms per month. Gas cost was then increased by $52,928,293 to recognize the level of fixed gas cost, Company Use, and LAUF amounts reflected in adjusted revenues based on current rates. The proposed Company Use and LAUF recovery rates are set forth on Hinson Direct Exhibit 5.

Q. IS THE COMPANY PROPOSING NEW FIXED GAS COST RECOVERY RATES?

A. Not at this time. Hinson Direct Exhibit 6 shows how much PSNC would expect to recover from customers based on normalized volumes and today's current rates. Using these dollar amounts and adjusted sales volumes the Company calculated new fixed gas apportionment rates that it would propose to use in any future changes to fixed gas rates or the determination of All Customers Deferred Account temporary increments or decrements.

Q. HAS PSNC PREPARED A COST OF SERVICE STUDY FOR USE IN THIS PROCEEDING?

A. Yes. A cost of service study was prepared by Company witness Taylor and is included in Item 3 of the Form G-1 filed in this proceeding. The per-books cost of service study summary is set forth in Item 3(a) of the Form G-1. An adjusted, or pro forma, cost of service study summary under present rates is set forth in Item 3(b) and a pro forma cost of service study summary under proposed rates is set forth in Item 3(d). Detailed workpapers supporting the cost of service study are also included in Item 3 of the Form G-1. Impacts of the proposed rate changes on customer class rates of return are shown in Schedule 1 of Item 3 and the proposed rates are presented in Schedule 7 of Item 3.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO RATE DESIGN IN THIS PROCEEDING?

A. No. The Company is proposing to maintain its present rate structure.

Q. IS THE COMPANY PROPOSING TO INCREASE THE BASIC FACILITIES CHARGE FOR ANY RATES OR TO CHANGE ANY FEES FOR LATE PAYMENTS, RETURNED CHECKS, OR RECONNECTION?

A. No. The Company is not proposing changes to any basic facilities charges or to any of its miscellaneous fees.

Q. HOW IS PSNC PROPOSING TO ADDRESS THE TCJA AND STATE INCOME TAX REDUCTIONS?

A. As discussed in Company witness Spaulding's testimony, PSNC is proposing to return EDIT resulting from recent reductions in the federal and state income tax rates partially through temporary rate decrements and partially through base rates.

Q. PLEASE DESCRIBE HOW PSNC PROPOSES TO IMPLEMENT THE INCOME TAX DECREMENTS.

A. PSNC proposes three riders, which are set forth in Hinson Direct Exhibit 7, to address certain impacts of the TCJA and state income tax reductions. These three riders are listed below and are further described in Company witness Spaulding's testimony:

Rider EDIT-1 Amortization of Federal Excess Deferred Income Taxes Rider

Rider EDIT-2 Federal Tax Act Revenue Deferred From Overcollections Rider

Rider EDIT-3 State Excess Deferred Income Taxes Rider

Q. PLEASE EXPLAIN HOW THESE TAX IMPACTS WILL BE REFLECTED IN THE RIDERS.

A. Schedule 1 of Hinson Direct Exhibit 8 shows the annual amortization amount, including applicable interest, for each rider. Schedule 2 shows applicable interest calculations through October 31, 2021. Schedule 3 shows the proposed amortization for the applicable period of each rider.

Q. HAVE YOU PROVIDED EXHIBITS REFLECTING THE PROPOSED RATE CHANGES?

A. Yes. PSNC's current rates and charges are set forth on Hinson Direct Exhibit 9. Hinson Direct Exhibit 10 shows the proposed rates and charges.

Q. IS THE COMPANY PROPOSING ANY CHANGES TO ITS TARIFF?

A. Yes. The Company is proposing changes to the rates and charges summary, rate schedules, riders, and service regulations and appendices of its tariff. A mark-up of the tariff showing all proposed changes is attached to my testimony as Hinson Direct Exhibit 11.

Many of the proposed changes are administrative in nature and are intended to clarify language, correct inconsistencies, and reorganize portions of the tariff. For example, the Company proposes to refer to itself as "Company" throughout the tariff instead of "PSNC" to remove any confusion associated with its assumed name of "Dominion Energy North Carolina" following the 2019 merger of SCANA into Dominion Energy, Inc. The Company also proposes to change the name of its "Rules and Regulations" to "Service Regulations" to eliminate potential confusion with the Commission's Rules and Regulations. I will generally describe other administrative-type changes in the testimony that follows.

There are also a few substantive additions being proposed. I will discuss these in more detail later in my testimony.

Q. WHAT ARE THE CHANGES THE COMPANY IS PROPOSING TO MAKE TO THE SUMMARY OF RATES AND CHARGES?

A. In addition to the new rates being sought, the Company proposes to add the rate for the voluntary surcharge associated with the GreenTherm™ Program. The Company is also clarifying note (a) regarding taxes.

Q. WHAT ARE THE CHANGES THE COMPANY IS PROPOSING TO ITS VARIOUS RATE SCHEDULES?

A. Most of the changes being proposed to the rate schedules are minor clarifications, such as revision of language regarding reconnection charges in the "Payment of Bills" section of the various rate schedules to track more closely language in Section 6 of the Service Regulations. In addition, the Company proposes to delete unnecessary and confusing language from Rate Schedule No. 126 Small General Service – Cooling, which is duplicative of language in Rate Schedule No. 125 Small General Service. The Company also proposes to add language regarding qualification for service to Rate Schedules No. 160 Special Sales Rate and No. 165 Special Transportation Rate that currently is only in Rate Schedule No. 150 Large-Quantity Interruptible Commercial and Industrial Service and Rate Schedule No. 180 Interruptible Transportation Service. This language should be included in the rate schedules in which the service is being offered.

Finally, the Company proposes to add residences certified to meet the standards of the North Carolina Energy Efficiency Code – High Efficiency Residential Option to those that qualify under Rate Schedule No. 102 High-

Efficiency Residential Service. This is discussed in the testimony of Company witness Herndon.

Q. WHAT CHANGES ARE BEING PROPOSED FOR THE COMPANY'S RIDERS?

A. In addition to the EDIT riders, the Company is adding new riders for its Conservation Programs (Rider F) and proposed GreenTherm™ Program (Rider G), which are discussed later in my testimony. The Company is also proposing to make several clarifying changes to its various existing riders, a few of which are described below.

The Company proposes making a procedural change to Rider B, which implements the customer classification review process in Commission Rule R6-12(7), by adding a sentence to Section II(e) to specify how a notice of change in a customer's service classification is given. The Company proposes that notice be given by registered or certified mail. This would allow the Company not to use a return receipt requested. The Company recognizes that its proposal would remove the return receipt requested requirement contained in the Commission's order issued in Docket No. G-100, Sub 48, dated February 22, 1991, but believes this requirement imposes an unnecessary administrative burden.

The Company proposes updating the interest rate for deferred accounts as set forth in Section VI of Rider C (CUT) and Rider E (IMT) to reflect the Company's requested return on equity and projected capital structure as of June 30, 2021. The Company also proposes adding a similar provision to

Section IV of Rider D (Purchased Gas Adjustment Procedures) so that the same interest rate will be applied to the Rider D deferred accounts. This will make explicit the Company's and Commission's prior practice.

The Company proposes to revise Section IV(b) and (c) of Rider E to reflect updated apportionment percentages from the cost of service study performed by Company witness Taylor and the annual therms shown in Item 4a.1 of the Form G-1.

Finally, Section XI of Rider E is revised to remove language requiring review of the rider four years after its effective date. The section retains language that the rider will be reviewed as part of a general rate case and that an interested party also may petition the Commission for review.

Q. PLEASE DISCUSS THE CHANGES THE COMPANY IS PROPOSING TO MAKE TO ITS SERVICE REGULATIONS.

A. The Company is proposing minor changes to the Service Regulations and Appendix A and Appendix B to the Service Regulations. I will not address every change being proposed but will briefly discuss those that warrant some explanation.

In Section 2 of the Service Regulations, definitions for "Company" and "Company Facilities" were added and definitions for "PSNC" and "PSNC Facilities" deleted to accommodate the Company's identification in the tariff that I mentioned above. Definitions for "Emergency Service" and "Unauthorized Gas" were added since these terms are used in the interruptible rate schedules and in Rider A. Definitions for "Service Regulations" and

"Tariff" also were added. The definition of "Excess Facilities" was clarified, including changes to make it more compatible with the definition of "Farm Tap" and with language in Section 24(c) of the Service Regulations regarding farm tap service. The Company is also proposing clarifying revisions to Sections 3, 4, 5, 6, 16, and 28 of the Service Regulations.

Appendix A to the Service Regulations, which is the form Transportation Pooling Agreement, and Appendix B, the Gas Quality Standards for Renewable Gas, both reflect similar organizational or administrative changes. In addition, Appendix A proposes a substantive change to Article VIII, which would allow poolers to trade imbalances. This proposal is responsive to requests by several poolers and will require programming changes to the Company's electronic bulletin board.

Q. IS THE COMPANY PROPOSING AN EXPANSION OF ITS CONSERVATION PROGRAMS?

A. Yes. PSNC is proposing to expand its existing conservation programs to reflect an increased commitment to sustainability, provide customers a broader range of options to conserve natural gas more wisely, and better serve underserved communities. The Company's proposals will double the number of programs and significantly increase the program budget to recognize customer preference to be more sustainable. Company witness Herndon will describe the proposed PSNC programs.

Q. WHAT EXPENDITURES IS THE COMPANY PROJECTING FOR ITS CONSERVATION PROGRAMS?

A. Herndon Direct Exhibit 3 sets forth PSNC's projected conservation program expenditures. Table C shows total projected expenditures by year.

Table C

2022	2023	2024	2025	2026
$2,930,702	$3,126,854	$3,715,360	$4,014,371	$4,023,329

Q. PLEASE EXPLAIN HOW PSNC WILL ACCOUNT FOR ITS CONSERVATION PROGRAMS.

A. PSNC currently has $750,000 in its rates for existing conservation programs. PSNC proposes to remove this amount from its rates and recover conservation program costs through deferred accounting treatment and a rider. PSNC's proposed Conservation Program Rider – Rider F is included in Hinson Direct Exhibit 11. The rider would allow PSNC to adjust its rates annually to recover costs associated with implementing the conservation programs. The Company would maintain a deferred account to track monthly conservation program expenses and amounts collected from customers. The Company would file monthly reports with the Commission detailing deferred account activity. The Company also proposes to file an annual report by March 31st summarizing conservation program costs and revenues for the previous twelve-month period ending December 31st, as PSNC has since the current programs' inception in 2009. For purposes of the annual rider adjustment, the Company proposes to file a summary of the conservation programs supporting its proposed adjustment of rates for customer classes.

Q. PLEASE DISCUSS THE GREENTHERM™ PROGRAM.

A. The GreenTherm™ Program is a voluntary renewable energy program offering an easy and convenient way for participating customers to support the development of renewable energy by purchasing "green attributes" of renewable natural gas. The program is modeled after one developed by an affiliated local distribution company, Dominion Energy Utah ("DEU"). The program is described in Company witness Herndon's testimony and the proposed GreenTherm™ Program Rider – Rider G is included in Hinson Direct Exhibit 11.

Q. HOW DO CUSTOMERS PARTICIPATE IN THE PROGRAM?

A. PSNC's customers participate in the program by electing to pay a monthly surcharge to purchase a block of green attributes. A block is equivalent to five therms of natural gas.

Q. HOW MUCH WILL CUSTOMERS BE CHARGED TO PURCHASE A BLOCK IN THE GREENTHERM™ PROGRAM?

A. If the GreenTherm™ Program is approved, the Company proposes to issue a request for proposals ("RFP") for the purchase of green attributes. The per-block rate will be determined once the Company receives the results of its RFP and the rate is approved by the Commission. Currently, DEU is charging $5 per five-therm block of green attributes.

Q. HOW WILL THE COMPANY ACCOUNT FOR AND MONITOR THIS PROGRAM?

A. The Company proposes to establish a deferred account to record monthly: (a) customer contributions; (b) marketing and administrative costs; (c) expenses associated with the purchase of green attributes; and (d) interest expense. PSNC will file monthly a report within 45 days after the end of the month of the activity recorded in the deferred account. Based on the deferred account balance and the price at which the Company can purchase green attributes, the Company could request authorization from the Commission to change the rate it charges customers for a block of green attributes.

Q. WHY IS THE COMPANY PROPOSING DEFERRED ACCOUNTING TREATMENT FOR THIS PROGRAM?

A. PSNC is proposing deferred accounting treatment to ensure that the cost of the program is borne by those customers choosing to participate. This will insulate the remaining customers from the uncertainty associated with the price at which green attributes can be purchased in the future as well as the level of participation in the program. The program will be available to all customer classes, including industrial customers, some of whom have indicated an interest in purchasing large quantities of green attributes.

Q. DO YOU BELIEVE THAT THE PROPOSED RATES AND OTHER COMPANY PROPOSALS IN THIS PROCEEDING ARE FAIR AND EQUITABLE FOR ALL CLASSES OF SERVICE?

A. Yes, I do.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

SUPPLEMENTAL TESTIMONY

OF

BYRON W. HINSON

AUGUST 10, 2021

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

A. My name is Byron W. Hinson. My business address is 400 Otarre Parkway, Cayce, South Carolina 29033. I am employed by Dominion Energy Services, Inc., as Director – Regulation for Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or the "Company").

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

A. N.C. Gen. Stat. § 62-133(c) and Commission Rule R1-17(c) permit PSNC 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 April 1, 2021, PSNC specifically reserved its right to make these updates. In that filing, PSNC based its revenue request on a number of pro forma adjustments that were developed on the basis of estimated going-level expense and utility rate base as of June 30, 2021. We now have available actuals rather than estimates to support those pro forma expense adjustments and utility rate base as of June 30, 2021. Furthermore, our Commission-approved customer billing rates have changed since the time of our application filing. For this reason, we are filing, concurrent with this Supplemental Testimony, the Supplemental Testimony and Exhibits of James A. Spaulding and John D. Taylor ("Supplemental Filing") to reflect the actual cost of service calculation as of June 30, 2021 and the components thereof relative to our original application.

Q. PLEASE EXPLAIN HOW, IF AT ALL, THIS SUPPLEMENTAL FILING IMPACTS THE TEST PERIOD AMOUNTS SHOWN BY PSNC IN ITS ORIGINAL APPLICATION AND GENERALLY DESCRIBE THIS FILING.

A. Nothing about this Supplemental Filing changes the per books test period amounts shown in PSNC's original application and in my Direct Testimony. The test period for this general rate case proceeding continues to be the 12-months ending December 31, 2020. This Supplemental Filing uses the known actuals at June 30, 2021, to update: 1) the pro forma utility rate base adjustments in the Company's original application that were developed based on then-estimated June 30, 2021, figures and amounts; 2) certain pro forma expense adjustments in the Company's original application that were developed based on then-estimated June 30, 2021, figures and amounts; and 3) the pro forma adjustment to utility gas sales and transportation revenue in the Company's original application that was developed based on the then-present Commission approved customer billing rates which have since been reset by this Commission.

Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR SUPPLEMENTAL TESTIMONY?

A. Yes.

Q. WERE YOUR SUPPLEMENTAL EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. PLEASE DESCRIBE YOUR SUPPLEMENTAL EXHIBITS.

The following Hinson Supplemental Exhibits 1 through 7 were prepared for this filing.

- Hinson Supplemental Exhibit 1 – Updates Hinson Direct Exhibit 1 presenting the revenue requirement requested in this proceeding;
- Hinson Supplemental Exhibit 2 – Updates Hinson Direct Exhibit 8 presenting the Company's balances for flowing through to customers the benefits resulting from excess deferred income taxes ("EDIT") associated with the federal Tax Cuts and Jobs Act of 2017 ("TCJA") and state income tax rate reductions addressed in Docket No. M-100, Sub 148, through rate riders;
- Hinson Supplemental Exhibit 3 – Updates Hinson Direct Exhibit 9 presenting present rates and charges;
- Hinson Supplemental Exhibit 4 – Updates Hinson Direct Exhibit 10 presenting proposed rates and charges;
- Hinson Supplemental Exhibit 5 – Updates Hinson Direct Exhibit 11 presenting a summary of proposed rates and charges;
- Hinson Supplemental Exhibit 6 – Updates Hinson Direct Exhibit 3 presenting proposed factors for Rider C;
- Hinson Supplemental Exhibit 7 - Updates Hinson Direct Exhibit 7 presenting EDIT Riders.

Q. WHAT IS PSNC'S UPDATED REVENUE REQUEST IN THIS PROCEEDING?

A. As is reflected on Hinson Supplemental Exhibit 1, PSNC is requesting approval of an annual revenue increase of $49,664,720 in this proceeding. The per-books adjustments, after updating the estimated amounts as of June 30, 2021, which were included in the Company's application, with actual amounts as of June 30, 2021[1], to recognize known and measurable plant investment in the Company's revenue and expense levels, result in an overall rate of return of 5.37% under current rates. The proposed rates result in an overall rate of return of 7.59%.

PSNC's updated revenue request in this proceeding represents an 8.65% increase from current effective revenues. This increase is partially offset by a 2.06% reduction in revenues due to the proposed updated flow-through of EDIT resulting from changes in the federal corporate income tax rates established under the TCJA as well as state income tax reductions.

Q. DID PSNC UPDATE THE PROPOSED INCOME TAX DECREMENTS?

A. Yes. PSNC updated the balances in the proposed three riders, which are set forth in Hinson Supplemental Exhibit 2, to address certain impacts of the TCJA and state income tax reductions. These three riders are listed below and are further described in Company witness Spaulding's direct testimony:

Rider EDIT-1 Amortization of Federal Excess Deferred Income Taxes

Rider

[1] Two exceptions are discussed in the Supplemental Testimony of James Spaulding

Rider EDIT-2 Federal Tax Act Revenue Deferred From Overcollections Rider

Rider EDIT-3 State Excess Deferred Income Taxes Rider

Q. HAVE YOU PROVIDED EXHIBITS REFLECTING THE UPDATED PROPOSED RATE CHANGES?

A. Yes. PSNC's updated present rates and charges are set forth in Hinson Supplemental Exhibit 3. Hinson Supplemental Exhibit 4 sets forth the updated proposed rates and charges. Hinson Supplemental Exhibit 5 is a proposed markup of the Summary of Rates and Charges of the Company's tariff, reflecting the proposed billing rates excluding the EDIT Riders. Hinson Supplemental Exhibit 6 shows the updated factors for Rider C associated with the updated cost of service and proposed rates.

Q. WHAT WILL BE THE IMPACT OF THE UPDATED REQUESTED RATE INCREASE ON PSNC'S CUSTOMERS?

A. This is an overall increase of approximately 6.59%, after the TCJA and state tax reductions, which is less than the rate of inflation of 8.97% since the Company's last general rate case proceeding in 2016. If PSNC's updated revenue request is granted, after the income tax offsets, the average residential customer's bill will increase by approximately $4 per month. Table A summarizes the updated revenue requirement and the effect of the proposed EDIT flow through.

Table A

	Updated Proposed Amounts	Updated Increase from Current Revenues
Revenue Requirement	$49,664,720	8.65%
EDIT Flow Through (Year 1)	($11,855,325)	(2.06%)
Net Impact	$37,809,395	6.59%

Q. PLEASE DISCUSS THE PRO FORMA UTILITY RATE BASE CHANGE IN PSNC'S UPDATED RATE BASE SINCE ITS LAST GENERAL RATE CASE.

A. PSNC's last general rate case reflected a test period ending December 31, 2015, updated for known and measurable changes through June 30, 2016. The amount of PSNC's rate base in that proceeding was $946.7 million, compared to approximately $1.7 billion as updated for actual known and measurable changes through June 30, 2021. Utility plant in service, which is the largest component of rate base, grew by almost $1.1 billion over this period. Table B presents the major categories of growth in plant by category, reflecting updated actuals through June 30, 2021.

Table B

Plant Asset Category ($ Thousands)	Test Period, With Adjustment, As of June 30, 2016	Test Period, With Updated Actuals, As of June 30, 2021
General Plant	$112,507	$125,741
Transmission Plant	$347,656	$988,155
Distribution Plant	$1,392,916	$1,871,852
Total Utility Plant	$1,853,079	$2,985,748

Q. DOES THE COMPANY'S SUPPLEMENTAL FILING INCLUDE THE INTEGRITY MANAGEMENT REVENUE REQUIREMENT IN BASE RATES?

A. Yes. Pursuant to Rider E the Company's original filing included in base rates the revenue requirement associated with integrity management capital investment as of December 31, 2020. In this Supplemental Filing, PSNC has removed a pro forma adjustment in rate base for the IMT plant projected to be installed between January 1, 2021, and June 30, 2021, and included the actual amount of IMT plant installed between January 1, 2021, and June 30, 2021. Rates pursuant to the IMT bi-annual adjustment, based on the January 1, 2021, through June 30, 2021, actual plant in service, will become effective with the IMT increment on September 1, 2021, if granted. The Company continues to propose moving the increment effective as of September 1, 2021, into base rates in this docket.

Q. HAS PSNC PREPARED AN UPDATED COST OF SERVICE STUDY AND PRESENT AND PROPOSED RATES FOR USE IN THIS PROCEEDING?

A. Yes. An updated cost of service study was prepared by Company witness Taylor. The Company also updated its present and proposed rates. Lost and unaccounted for and fixed gas costs rates will be updated to reflect the throughput that the Commission approves in this proceeding.

Q. DO YOU BELIEVE THAT THE PROPOSED RATES AND OTHER COMPANY PROPOSALS IN THIS PROCEEDING ARE FAIR AND EQUITABLE FOR ALL CLASSES OF SERVICE?

A. Yes.

Q. DOES THIS COMPLETE YOUR PREFILED SUPPLEMENTAL TESTIMONY?

A. Yes, although I reserve the right to supplement further or amend my testimony before or during the Commission's hearing in this proceeding.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

REBUTTAL TESTIMONY

OF

BYRON W. HINSON

OCTOBER 7, 2021

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

A. My name is Byron W. Hinson. My business address is 400 Otarre Parkway, Cayce, South Carolina 29033. I am employed by Dominion Energy Services, Inc., as Director – Regulation for Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or the "Company").

Q. ARE YOU THE SAME BYRON W. HINSON WHO PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

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

A. The purpose of my rebuttal testimony is to:

- Agree with Public Staff witness John R. Hinton's proposed 2% inflation rate and 40-year evaluation period for purposes of PSNC's gas extension feasibility model, but rebut Mr. Hinton's proposal for the Company to file for an exception to Commission Rule R7-16(b)(1) when extending gas service to new customers in new subdivisions where costs are substantial.
- Rebut Public Staff witnesses James M. Singer and David M. Williamson's proposal to remove the High Efficiency Discount Rate from proposed Rider F and place a level of program costs in the Company's cost of service.

- Provide support for PSNC's participation in stakeholder meetings to discuss issues regarding affordability, as proposed by Public Staff witness Jack L. Floyd.
- Agree with Public Staff witness Julie G. Perry's testimony regarding the integrity management tracker ("IMT") mechanism.
- Provide support for the Company's research and development initiative.
- Provide support for the Company's voluntary GreenTherm™ program and Rider.

GAS EXTENSION FEASIBILITY MODEL

Q. DO YOU OPPOSE PUBLIC STAFF WITNESS HINTON'S RECOMMENDATIONS REGARDING THE NPV GUIDELINES AND HIS RESULTING 2.0% LONG-TERM INFLATION RATE.

A. No. The Company accepts Mr. Hinton's recommendations related to term and inflation rate in the model. PSNC will work with the Public Staff to implement the necessary changes to the model.

Q. IS IT REASONABLE TO ACCEPT PUBLIC STAFF WITNESS HINTON'S SUGGESTION THAT THE COMPANY FILE FOR AN EXCEPTION TO RULE R7-16 WHEN NEW RESIDENTIAL GAS EXTENSION PROJECTS REQUIRE SUBSTANTIAL CAPITAL?

A. No. It is unreasonable to accept Public Staff witness Hinton's suggestion that the Company file for an exception to the Rule R7-16(b)(1) PSNC extends gas service to new customers in new subdivisions where costs are substantial.

First, Rule R7-16(b)(1), cited by Mr. Hinton, is applicable to the extension of water mains, not natural gas lines, which are governed by Rule R6-11. Additionally, even if Rule R7-16 were applicable to natural gas mains, Section (b)(1) expressly excludes subdivisions.

Second, Section 23(d) of the Company's Rules and Regulations provides an allowance for mains and service lines for distances totaling up to 200 feet, which considers only existing structures for extensions to new subdivisions.[1] This limitation on the 200-foot allowance has been in the Company's approved Rules and Regulations for at least 25 years as an appropriate exception to the extension allowance.

HIGH EFFICIENCY DISCOUNT RATE PROGRAM COSTS

Q. DO YOU AGREE WITH PUBLIC STAFF WITNESSES JAMES M. SINGER AND DAVID M. WILLIAMSON'S RECOMMENDATION TO KEEP HIGH EFFICIENCY DISCOUNT RATE PROGRAM COSTS IN BASE RATES?

A. No, I do not agree with the recommendation to keep the High Efficiency Discount Rate program costs in the Company's base rates rather than being included in the proposed Rider F with the other energy efficiency ("EE") programs. The Public Staff's recommendation is based on their perception that it "may be difficult" for the High Efficiency Discount Rate program to generate savings apart from savings resulting from the Residential New Construction program or other EE programs.

[1] As background, Section 23(d) of the Company's Rules and Regulations states in part, "For proposed new sub-divisions, the allowance for extensions of Mains and Service Lines will be considered only for existing structures that plan to use Gas at the time the Main is to be extended."

PSNC witness Jim Herndon's testimony clearly delineates the anticipated savings of each of the programs, including the High Efficiency Discount Rate program. The Company can alleviate the Public Staff's concern by tracking the savings associated with each program that its customers are qualifying under. The Commission should reject the Public Staff's recommendation to remove the High Efficiency Discount Program from the Company's proposed EE portfolio, which would remove it from the Rider F tracking mechanism.

AFFORDABILITY

Q. HOW DO YOU RESPOND TO PUBLIC STAFF WITNESS FLOYD'S RECOMMENDATIONS REGARDING AN AFFORDABILITY STAKEHOLDER PROCESS?

A. The Public Staff recommends that the Commission consider issues of affordability for low-income natural gas residential customers that were recently raised in several electric rate case dockets for low-income electric residential customers. Public Staff witness Floyd recommends that the Commission issue an order either convening a stakeholder process separate from Duke Energy Carolinas, LLC's ("DEC") and Duke Energy Progress, LLC's ("DEP") current, ongoing affordability stakeholder process, or, alternatively, require PSNC to join the existing DEC and DEP affordability stakeholder process.

PSNC agrees with Public Staff witness Floyd that affordability for low-income natural gas residential customers is an important issue, and PSNC supports a coordinated approach among the utilities to hold stakeholder meetings to discuss affordability.

IMT MECHANISM

Q. PLEASE DESCRIBE PUBLIC STAFF WITNESS PERRY'S RECOMMENDATIONS WITH REGARD TO PSNC'S INTEGRITY MANAGEMENT REVENUE REQUIREMENT ("IMRR") MODEL.

A. As discussed in the Public Staff's 2020 Annual IMT Report in Docket No. G-5, Subs 565C and 628, the Public Staff determined during its review of PSNC's IMRR model that additional modifications to the model may be needed to address some of the Public Staff's concerns. Public Staff witness Perry states that the Public Staff plans to send PSNC a template of its proposed modifications to the mechanism prior to the Company's annual IMT filing on January 31, 2022 and will work with the Company to implement the recommended changes. She also states that the Public Staff will work with the Company to update the tariff inputs for the margin percentages by month and by rate class, as well as the special contract credits once this proceeding is complete and a final order issued.

Q. DOES PSNC AGREE WITH THE PROCESS PROPOSED BY PUBLIC STAFF WITNESS PERRY TO MODIFY THE IMT MECHANISM AND UPDATE THE TARIFF?

A. Yes. PSNC looks forward to reviewing the Public Staff's template of proposed modifications to the mechanism prior to the Company's Annual IMT filing on January 31, 2022 and agrees to work with the Public Staff to implement any necessary changes. PSNC also agrees to work with the Public Staff to update the tariff inputs for the margin percentages.

RESEARCH AND DEVELOPMENT

Q. PLEASE SUMMARIZE PSNC'S RESEARCH AND DEVELOPMENT PROPOSAL INCLUDED IN THE COMPANY'S APPLICATION.

A. PSNC has proposed a research and development initiative that focuses on studying the effects of blending hydrogen with natural gas and determining the safety and viability of such blended natural gas. To fund this initiative, the Company has proposed a $285,000 adjustment. This specific cost adjustment is based on a PSNC affiliate's similar, successful hydrogen pilot project in Utah, which focuses on studying the feasibility of hydrogen blending, its availability, storage, and pricing. PSNC believes that the adjustment is reasonable, based on a similar pilot program, and supportive of environmental sustainability.

Q. DOES THE PUBLIC STAFF SUPPORT THIS RESEARCH AND DEVELOPMENT PROPOSAL?

A. No. Public Staff witness Neha R. Patel states that the Public Staff does not agree with the Company's proposal. Ms. Patel states that PSNC has not provided "any costs specific to this program for North Carolina," and that the Public Staff should be given the opportunity to examine such new projects and make recommendations to the Commission before its implementation.

Q. HAS PSNC PROVIDED THE PUBLIC STAFF ADDITIONAL INFORMATION ON ITS PROPOSED HYDROGEN RESEARCH AND DEVELOPMENT INITIATIVE?

A. The Company recently provided the Public Staff a more detailed cost breakdown of PSNC's proposed hydrogen research and development initiative. The Company believes that this provided the Public Staff with the information necessary to support the Company's proposal.

Q. DOES THE PUBLIC STAFF SUPPORT THE GREENTHERM™ PROGRAM?

A. Yes. Public Staff witness Patel states that the Public Staff supports the development of a voluntary GreenTherm™ program and recommends that the Commission order PSNC to proceed with the development of the program. However, the Public Staff does not believe that the program should receive final approval until the Company has received the results of its request for proposals ("RFP"), determined the cost of a block of therms, and determined the sources for the renewable gas. The Public Staff also advocated for the Company to consider carbon offsets.

Q. PLEASE DESCRIBE THE PURPOSE AND THE STATUS OF THE PROGRAM.

A. The GreenTherm™ program will enable the Company's customers, who choose to be more environmentally sustainable, to purchase renewable natural gas ("RNG") attributes. The Company is developing the RFP for the RNG attributes. PSNC anticipates that the results of the RFP and related pricing will be completed in the first quarter of 2022.

Q. WHAT IS THE COMPANY'S REQUEST REGARDING THE GREENTHERM™?

A. The Company requests that the Commission approve the GreenTherm™ program and Rider G in this proceeding on the condition that the Company promptly file the RNG attribute costs and other supporting information for Commission approval after responses to the Company's RFP are received. The Company believes that this proposed conditional approval will yield more meaningful bids. The Company agrees with the Public Staff's recommendation to price the GreenTherm™ per-therm block attributes before the Commission considers final approval of the program, and the Company will provide the details to the Public Staff for review before filing with the Commission. The Company will evaluate the benefits of including carbon offsets in its RFP and provide the Public Staff an update in the first quarter of 2022.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

SETTLEMENT TESTIMONY

OF

BYRON W. HINSON

OCTOBER 15, 2021

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

A. My name is Byron W. Hinson. My business address is 400 Otarre Parkway, Cayce, South Carolina 29033. I am employed by Dominion Energy Services, Inc., as Director – Regulation for Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or the "Company").

Q. ARE YOU THE SAME BYRON HINSON WHO PREFILED DIRECT, SUPPLEMENTAL, AND REBUTTAL TESTIMONY IN THIS PROCEEDING?

A. Yes, I am.

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

A. My Settlement Testimony explains the customer impact of PSNC's rate case as reflected in the Stipulation of Settlement ("Stipulation") between PSNC, the Public Staff - North Carolina Utilities Commission ("Public Staff"), the Carolina Utility Customers Association, Inc. ("CUCA"), and Evergreen Packaging, LLC ("Evergreen") (together, the "Stipulating Parties"). My Settlement Testimony also addresses certain other components of the Stipulation.

Q. HOW DID THE PUBLIC STAFF CONDUCT 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 investigation spanned 28 weeks, entailed 124 sets of data requests directed to the Company containing approximately 840 discrete questions (not including parts and subparts), and included numerous informal follow-up questions and calls.

Q. HAS PSNC REACHED A SETTLEMENT WITH OTHER PARTIES TO THIS CASE?

A. Yes. PSNC and the Public Staff also negotiated with CUCA and Evergreen, who joined in the settlement after a proposed rate design was developed that was acceptable to all the Stipulating Parties. We contacted the Attorney General's Office although they did not file testimony in this proceeding.

Q. WHAT IS THE SETTLEMENT REVENUE REQUIREMENT IN THIS PROCEEDING?

A. The settlement results in a revenue requirement increase of approximately $29.5 million in the Company's annual operating revenues. The per-books adjustments, after the update to recognize known and measurable plant investment in the Company's revenue and expense levels as of June 30, 2021, net of settlement adjustments, result in an overall return of 5.74% under current rates. The proposed rates result in an overall rate of return of 7.07%.

The settlement revenue requirement represents an overall 5.12% increase from current effective revenues. This increase is partially offset by a 4.64% reduction in revenues due to the flow-through of excess deferred income taxes ("EDIT") resulting from reduction in the federal corporate income tax rate from 35% to 21% established under the Tax Cuts and Jobs Act ("TCJA") as well as state income tax reductions.

Q. WHAT IS THE IMPACT OF THE SETTLEMENT ON PSNC'S CUSTOMERS?

A. The revenue requirement the Company filed with its application was reduced through the discovery and settlement process with the Public Staff. The settlement results in an overall customer increase of approximately 5.12%, before the TCJA and state tax reductions, which is slightly more than half the rate of inflation of 8.97% since the Company's last general rate case proceeding in 2016. If the Stipulation is approved, after the EDIT flow through, the average residential customer's bill would increase by less than $1 per month. Table A summarizes the settlement revenue requirement and the effect of the impact of the EDIT flow through.

Table A

	Proposed Amounts	Increase from Current Revenues
PSNC Filed Revenue Requirement as Updated on June 30, 2021	$49,664,720	8.65%
Settlement Reduction to Revenue Requirement	($20,200,367)	(3.53%)
Net Settlement Revenue Requirement	$29,464,353	5.12%
EDIT Flow Through (Year 1)	($25,022,095)	(4.64%)
Net Impact (Year 1)	$4,442,258	0.48%

Q. DO YOU BELIEVE THAT THE OVERALL SETTLEMENT REACHED BY THE PARTIES AND PRESENTED TO THE COMMISSION IS JUST AND REASONABLE?

A. Yes, I do.

Q. DOES THE STIPULATION RESOLVE ANY OTHER ISSUES THAT YOU WOULD LIKE TO ADDRESS?

A. Yes. The Stipulation provides for:

(1) Continuation of the Integrity Management Rider ("IMT") mechanism.

(2) Moving the current cumulative IMT revenue requirement, as of September 1, 2021, into base rates.

(3) Approval of PSNC's proposed modifications to its Tariff, including modifications to its rate schedules and service regulations.

(4) Approval of and recovery of deferred transmission integrity management program ("TIMP") expenses and distribution integrity management program ("DIMP") expenses and continuation of the TIMP and DIMP deferrals through the Company's next rate case.

(5) Approval of new and modified Energy Efficiency ("EE") programs for a three-year pilot and a rider (Rider F to PSNC's Tariff), to be finalized and filed within 15 business days. The rider will facilitate the recovery of all approved EE program expenses on a going-forward basis.

(6) Inclusion of PSNC's current discount rate program cost in base rates.

(7) Participation in an affordability stakeholder collaborative.

(8) Revisions to PSNC's model used to calculate the feasibility of extending natural gas service to its customers.

(9) Provisional approval of the voluntary GreenTherm™ program and cost recovery rider (Rider G to the Company's Tariff), subject to certain specifications of the program prior to final approval.

(10) Approval of Public Staff witness Perry's calculation of EDIT riders.

(11) Approval of hydrogen research and development expenses.

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 settlement 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 results in rates that are significantly lower than PSNC's proposed rates in this proceeding.

Q. WHAT ARE YOU REQUESTING THE COMMISSION DO IN THIS PROCEEDING?

A. I am requesting that the Commission, based on its review of the Stipulation and evaluation of all the evidence presented, approve the terms of the Stipulation as just and reasonable.

Q. DOES THIS CONCLUDE YOUR SETTLEMENT TESTIMONY?

A. Yes, it does.

MS. GRIGG: Thank you. The witness is available for cross-examination.

COMMISSIONER BROWN-BLAND: All right. Cross from this -- for this witness?

MS. FORCE: We have some questions. I do have some questions.

COMMISSIONER BROWN-BLAND: All right. Ms. Force, go right ahead.

MS. FORCE: Thank you.

CROSS-EXAMINATION BY MS. FORCE:

Q. Mr. Hinson, I'm Margaret Force, with the Attorney General's Office, and I do have a few questions for you about the commodity cost of gas.

Do you have a copy of the proposed cross exhibits that were submitted for the AGO?

A. I do.

Q. Okay. Good. I have a couple of questions for you about that second exhibit. So -- but turning first to Page 9 of your initial testimony, you discussed PSNC's proposed adjustments to the test period cost of gas and said that you used .25 dollars per therm, so 25 cents --

A. That's correct.

Q. -- as the commodity cost of gas.

A. That's correct.

Q. And am I right that that would be the equivalent of $2.50 per dekatherm?
A. Per therm.
Q. I'm sorry. It's -- it's .25 --
A. Right. Correct. Correct.
Q. -- per therm, so that would be 2.50 per dekatherm?
A. Correct.
Q. Okay. Thanks. Lawyer math.
PSNC was allowed to increase the commodity benchmark -- benchmark cost of gas from $2.50 per DT, or dekatherm, to $3.75 per dekatherm effective October 1st, right?
A. That is correct.
Q. Okay. And that, just by reference, was in Docket Number G-5, Sub 637. And that earlier $2.50 benchmark was in effect all the way back to last November, November 1st, 2020; is that right?
A. That's right. Subject to check.
Q. And before that, the benchmark was $2.00 per dekatherm, correct?
A. Subject to check.
Q. Okay. Sure. I'd ask you to look now at what was submitted earlier as AGO Proposed Cross Exhibit 2.
MS. FORCE: And I'd ask that this be marked for

identification in the case as AGO Hinson Cross Exhibit 1, if -- if that's agreeable.

COMMISSIONER BROWN-BLAND: All right. It will be so identified as AGO Hinson Cross-Examination Exhibit 1.

MS. FORCE: Thank you.

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

BY MS. FORCE:

Q. And, Mr. Hinson, do you recognize this as a Reuters item, at least on the face of it, dated October 4th, 2021?

A. I do.

Q. All right. And you're -- are you familiar with Reuters as a publication that's a well-established financial information publication?

A. I recognize it as a source of news.

Q. Okay. Okay. And the title of that is "Analysis: Global natgas price surge looms for the United States this winter." If you look down to the fourth paragraph -- it's a four-page document and that's on Page 2 -- it indicates that the U.S. natural gas contract price has been rallying and lately hit seven-year highs at $5.62 per million BTU.

Could you help us with equating that to dekatherms?

A. I have not done that math. I will tell you, based on the latest pricing I've seen, it's about $5.23.

Q. Okay. And so it's roughly equivalent then to the dekatherm price. And -- and then moving over to the next page -- that's Page 3 of the document -- Henry Hub is a -- a terminal that's familiar here, and it indicates that the nation's benchmark recently passed $6.00 for the first time since 2014, right?

A. I guess it would depend on the definition of recently. The latest pricing I've seen is around five -- a little higher than $5.00.

Q. Okay. So it dropped back down a little bit?

A. Right.

Q. Okay. The article speaks for itself. It actually references prices in Europe and how they may tend to be driving the increases over the course of the winter.

To clarify, the rate changes for gas costs are not something that are fixed in the general rate case. Isn't that right? They can change.

A. Yes, but -- right. So when we -- when you referenced our benchmark going from 2.50 to 3.75, that was done under the PGA rules, under Rider D. And so that was done outside of the rate case pursuant to that rider.

Q. That's right. So when we're talking -- just for clarification, when we're talking about the rate increase that's -- that might be allowed under the stipulation then under the provisions of this general rate case, that rate increase is to the margin rates, not the -- the gas costs; is that right?

A. Not -- not -- we did not change the commodity as part of the rate case.

Q. Thank you. That's -- that's what I was asking and you said it better than I did.

I don't have any other questions for you. I appreciate it, Mr. Hinson.

A. You're welcome.

COMMISSIONER BROWN-BLAND: All right. I don't indicate there's cross by anyone else for -- for this witness, but if so, speak up.

(No response.)

COMMISSIONER BROWN-BLAND: All right. Are there any questions from the Commission? Chair Mitchell?

CHAIR MITCHELL: Commissioner Brown-Bland, if I may.

COMMISSIONER BROWN-BLAND: Yes.

EXAMINATION BY CHAIR MITCHELL:

Q. All right. Good morning, Mr. Hinson. How are you?

A. Good morning, Chair Mitchell.

Q. Thank you for being here with us this morning. I have a few questions for you.

Mr. Hinson, I'm going to put you on the spot here and ask you some questions about one of your colleague's testimony, so just do your best to answer --

A. All right.

Q. -- recognizing that I'm not asking you about your testimony here.

But company witness Harris in his direct testimony indicated that the company's projected capacity requirements indicate a significant shortfall absent the successful completion of the MVP projects, mentioned some additional benefits that the -- the successful completion of the MVP projects would provide to the company, including supply security and access to gas from a shale -- one of the shale regions.

So my question for you is this, Mr. Hinson. What if the MVP projects are not successfully completed and placed into service? What is -- how is the company planning to address that, the -- the shortfall that you-all anticipate?

A. Well, I'm not a party to that level of discussions, but I would imagine we would be considering all the options we have available to us should the MVP pipeline not be completed.

Q. And those options would include?

A. I would be speculating if I provided an answer, but I would imagine the company would consider such things as a L&G facility or another way to source our gas. It really is a shame that Transco is -- is the only pipeline into North Carolina.

Q. Mr. Hinson, to the extent that you can -- can answer this -- and, you know, if you're speculating, you can so indicate, but is there additional -- would the company seek additional firm transportation capacity on Transco? Is that even available?

A. I'm not sure if it's available, and that's probably a good question for gas supply. But I would imagine that we would explore that option.

Q. Okay. And what do you know, if anything, at this point about costs associated with -- with firm capacity on Transco as we look into the future?

A. I have not looked at the firm capacity on Transco. I'm thankful we have Ms. Jackson -- Ms. Rose Jackson available to do that.

Q. Well, I'm thankful --

A. I imagine we would take a look at that.

Q. All right. All right. But thank you for entertaining those questions.

Another -- another question for you, Mr. Hinson, about Mr. Harris's testimony. In his testimony, he indicated that the -- the initial request of the company, which was the fifty-nine -- thereabouts -- million dollar increase in -- in revenue requirement would have a bill impact on residential customers of about $4.00 a month.

Have you-all come up with what the impact to residential customers would be on a monthly basis given the settled upon revenue requirement?

A. We have. And in Year 1, net of the EDIT benefit -- which let me back up and say this. In the settlement, we settled at 29 million. The first year EDIT give-back is 25 million.

So it's a minor increase the first year. So the first year, it's, like, a 52 cents increase in the residential bill from current rates, or about one percent.

Q. Okay. And then recognizing that for the benefits to the customers would be EDIT flowback decrease over time, do you-all -- have you-all projected customer impacts going out past that first year?

A. We have. It looks like, subject to check, about $2.48 in Year 2 to the residential bill to current rates today, or about 4.7 percent. And then it scales up to the 5.12 percent overall increase after Year 3, I believe.

Q. Okay. And what is the -- help me understand. Sort of translate the five-plus increase into impact on the bill.

A. I think that's -- subject to check, I think it's $2.75 --

Q. Okay.

A. -- or the five percent increase --

Q. Okay.

A. -- once EDIT is rolled off.

Q. Okay. All right. Thank you, Mr. Hinson.

Now one more question for you sort of turning -- changing gears. Talking -- I'm interested in the $750,000 that the company removed from cost of service associated with the -- the energy efficiency rate discount program. Are you --

A. Right.

Q. Are you -- okay. You're with me there.

A. Right.

Q. All right. And then my understanding is the Public Staff made an adjustment and put back four hundred and twenty-four thousand and change back into the revenue requirement.

And I understand that's a -- that's a multi-year average of the cost to the company associated with that program; is that correct?

A. Correct.

Q. Okay. Now, help me understand, what does that -- what does that four hundred and twenty-four include? Is it just cost to the company associated with the discount rate or is there -- you know, so -- so actual sales to the customers or is there -- is there -- are there additional components to that cost?

A. In our Conservation Program filing with you-all in -- in Sub 495A, Section 5 -- and you don't have to look at it. I'm already -- that section identifies the cost which was mentioned earlier by, I think, Commissioner Brown-Bland of the three programs that are currently in effect, and that's $795,369. That's the cost of the Conservation Program overall.

The cost of the high-efficiency discount rate was included in that number, $398,829, which is the annual amount for each of the cost elements incurred for the Conservation Program, specifically the high-efficiency discount rate. So I think that's the cost of the high-efficiency discount rate for those customers who participate.

Q. Okay. But does it include, for example, rebates paid to homebuilders or developers or --

A. I don't -- subject to check, I don't think so.

Q. Okay. Okay. All right. Thank you, Mr. Hinson. That's all I have for Mr. Hinson. So thank you very much.

A. You're welcome.

EXAMINATION BY COMMISSIONER BROWN-BLAND:

Q. All right. Mr. Hinson, since you ended talking about the Sub 495A, do you recall my question to Mr. Spaulding about the seven hundred ninety-five thousand and some change versus the seven hundred and fifty that was taken out after -- after the settlement? If you -- can you -- if you have an explanation --

A. I do. We -- I think there was $750,000 in rates. And what the company spent that particular year was 795,000, which is an amount greater which was not recovered through rates. So that's the difference in the two numbers.

Q. All right. Thank you for that.

COMMISSIONER BROWN-BLAND: Before I ask anything further, let me see if my colleagues have questions.

(No response.)

COMMISSIONER BROWN-BLAND: Seeing no -- not hearing anyone.

BY COMMISSIONER BROWN-BLAND:

Q. All right. My questions are really requests at this point for late-filed exhibits, but if you have anything that -- that trigger in your mind, feel free to give us testimony about it.

Mr. Hinson -- and -- and we can make this available, but -- to be sure that we get what we're asking for here, but I would like to know if the company would provide a late-filed exhibit showing the percentage increase and the bill increase for a average residential customer per month for Years 1 to 5 as a result of the Stipulation in this -- in this docket.

A. We can do that. Happy to do it.

Q. All right. And then on Page 6 of the Stipulation, it states that the updated company use and lost and unaccounted for gas factor is .976 percent.

Could you provide a late-filed exhibit showing the breakdown of the company use and that lost and unaccounted for gas volumes in the dockets for Sub 565 and 495?

A. We can do that.

Q. And also a late-filed exhibit showing the company use and lost unaccounted for gas factors in -- in 565 and 495. And if you find that the gas factors have increased since the 2008 rate case, could you please provide the reasons that you're able -- that you find for the increase,

the reasons that you determined --
A. Be happy to.
Q. -- caused the increase?
A. And I'll look at my counsel and ask if she's got that written down just because I didn't.
MS. GRIGG: I think we do. And we'll certainly reach out to the Commission should we have any questions about what is required.
COMMISSIONER BROWN-BLAND: All right. And as I said, we do -- we do have this down, so we'll be able to give it to you.
BY COMMISSIONER BROWN-BLAND:
Q. And the last one is could you provide a schedule that reconciles the total revenue of $535,018,991 shown on Settlement Exhibit C --
A. Uh-huh (yes).
Q. -- Schedule 3 of 3, Column C with the total sales and transportation revenue of $573,632,002 shown on Settlement Exhibit 1, Schedule 1 of 2, Column C?
A. We can do that. Happy to do it.
Q. All right. We think the dollar difference there is supposed to be the margin decoupling adjustment and the integrity management rider revenues that we see on Patel Exhibit 2, but we didn't see the supporting schedule.

A. We can provide it.

Q. The amounts seem to be different from Hinson Direct Exhibit 2, so that's the reason for our inquiry.

Q. Okay.

A. It's likely the INT, subject to check.

Q. All right. Thank you for that.

COMMISSIONER BROWN-BLAND: So is there -- none of my Commissioners have anything else. So is there questions on the Commission's questions?

MS. GRIGG: No, ma'am.

COMMISSIONER BROWN-BLAND: All right. I don't hear any from anyone else. So, Ms. Force?

EXAMINATION BY MS. FORCE:

Q. I'm sorry. I did have one question as follow-up, and I'm -- just for the record, do you know -- are you aware of the filing that was made, Mr. Hinson, last week by -- for revised temporary rates for Public Service?

A. Yes.

Q. And on that, there was a redline that shows sort of earlier percentage change, and -- and it shows the difference in revenues existing under the temporary rates that would take effect.

Are those reflecting the total rate increase, to your knowledge, or are those the Year 1 increase that were the basis for what was requested for temporary rates?

A. You're asking me about the table that was supplemented in the other --

Q. Yes.

A. If it's the table that lists all the rate increases and the percentages, if that's what you're referring to --

Q. That's right.

A. -- we -- when we filed the undertaking, it was with the settlement in principle with the Public Staff. And subsequent to that filing, we settled with CUCA and Evergreen. So we supplemented the filing to include the results of the Stipulation of Settlement, the totality of the case, so that the rates that would go in -- on -- under temporary rates would be the settlement rates that we've been talking about this morning in the Stipulation of Settlement.

Q. Okay. And so when you talk about the percentage change of 5.93 for residential service, how does that correspond to the 52 cents in Year 1 that comes after EDIT?

Am I getting too much into the weeds for you to be able to answer that question?

A. Well, that's -- so the --

Q. Oh, I'm sorry.

A. -- is a bill impact. Fifty-two cents --
Q. Yeah.
A. -- is bill to bill.
Q. Okay. I -- I follow you now. That's the -- that's the amount that -- in a month that customers would --
A. Right.
Q. -- see a difference on average. But the overall percentage increase in Year 1 would be 5.93 percent.
A. Right. What --
Q. For residential customers.
A. After all the EDIT rolls off. So in the first year, you've got the EDIT benefit to get back for Years 1 through 5. So that's without EDIT.

But I would -- I would go and -- I would mention to you that when the rates -- settlement rates go effective on November 1st, the company also plans to push out the EDIT benefit to customers on that same day.
Q. I see. Okay. All right. Thank you. I appreciate --
A. That would reduce the 5.93 percent.
Q. Right. Okay. I think I follow you.

MS. FORCE: Those are -- that's my question. If there's no follow-up -- no more questions, then I'll ask that the exhibit for the Attorney General --

COMMISSIONER BROWN-BLAND: Ms. Grigg, do you have follow-up or redirect, I'll call it?

MS. GRIGG: No, ma'am.

COMMISSIONER BROWN-BLAND: All right. Ms. Force, now.

MS. FORCE: Okay. I believe we identified the exhibit as AGO Hinson Cross Exhibit Number 1. I'd ask that that be admitted into evidence.

COMMISSIONER BROWN-BLAND: Without objection, it will be received into evidence at this time.

MS. FORCE: Thank you.

(AGO Hinson Cross-Examination Exhibit 1 was received into evidence.)

COMMISSIONER BROWN-BLAND: Ms. Grigg?

MS. GRIGG: Yes, Commissioner Brown-Bland. I move that Mr. Hinson's 11 direct exhibits and seven (7) supplemental exhibits as premarked be entered into evidence.

COMMISSIONER BROWN-BLAND: All right. Those exhibits will be received into evidence at this time.

(Hinson Direct Exhibits 1 through 11 and Hinson Supplemental Exhibits 1 through 7 were received into evidence.)

COMMISSIONER BROWN-BLAND: Seeing no further questions for witness Hinson, thank you and you may be excused.

THE WITNESS: Thank you.

COMMISSIONER BROWN-BLAND: All right. Ms. Grigg, the case is still with you.

MS. GRIGG: Yes, ma'am. I would like to make sure that we enter into the record the testimony and exhibits of the witnesses whom the Commission excused, if that's not already been taken care of through the Order, and also some additional documents prefiled by the company.

COMMISSIONER BROWN-BLAND: All right. Go ahead at this time. I believe that the Order simply would be received at the hearing.

MS. GRIGG: Thank you. I will start with direct and then go through supplemental and rebuttal testimony.

I would like to move that the following direct testimonies as filed on October 15th, 2021, be entered into the record and the exhibits be premarked -- be marked as prefiled.

COMMISSIONER BROWN-BLAND: Ms. Grigg, do you mean -- do you mean April 1st?

MS. GRIGG: Yes, ma'am. I do. I apologize.

COMMISSIONER BROWN-BLAND: April 1st, 2021. Okay.

MS. GRIGG: Yes, ma'am. I had a typo. Thank you.

The direct testimony of D. Russell Harris, consisting of 15 pages; the direct testimony of M. Shaun Randall -- "M" as in Mary -- consisting of 18 pages; the direct testimony of Michael B. Phibbs, consisting of nine (9) pages; the direct testimony of Mr. John D. Taylor, consisting of 25 pages as well as -- as well as Taylor Direct Appendix A; the direct testimony of John J. Spanos, consisting of 18 pages and Spanos Direct Exhibits 1 through 3; and the direct testimony of James Herndon, consisting of 17 pages and Herndon -- Herndon Direct Appendix A and B, as well as Herndon Direct Exhibits 1 through 3.

COMMISSIONER BROWN-BLAND: All right.

MS. GRIGG: I'll move -- I'll move on to supplemental testimony.

COMMISSIONER BROWN-BLAND: Let me take care -- let me -- let me take care of those, if you will.

MS. GRIGG: Yes, ma'am.

COMMISSIONER BROWN-BLAND: So those direct testimonies just identified by counsel will be received into the record as -- and treated as if given orally from the witness stand.

The exhibits referenced will be identified as they were marked when prefiled and they will be received into evidence at this time.

(Spanos Direct Exhibits 1 through 3 and

Herndon Direct Exhibits 1 through 3 and Appendix A and B were marked for identification and received into evidence.)

(Whereupon, the prefiled direct testimony of D. Russell Harris, the prefiled direct testimony of M. Shaun Randall, the prefiled direct testimony of Michael B. Phibbs, the prefiled direct testimony and Appendix A of John D. Taylor, the prefiled testimony of John J. Spanos and the prefiled direct testimony of James Herndon were copied into the record as if given from the stand.)

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632

DIRECT TESTIMONY

OF

D. RUSSELL HARRIS

APRIL 1, 2021

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

A. My name is D. Russell Harris and my business address is 400 Otarre Parkway, Cayce, South Carolina 29033. I am Vice President and General Manager of Gas Operations for Dominion Energy South Carolina, Inc. ("DESC") and Vice President and General Manager of Southern Distribution for Public Service Company of North Carolina, Inc., d/b/a/ Dominion Energy North Carolina ("PSNC" or the "Company"). DESC and PSNC are wholly-owned subsidiaries of SCANA Corporation ("SCANA"), which is wholly owned by Dominion Energy, Inc. ("DEI").

Q. PLEASE BRIEFLY OUTLINE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I am a 1986 graduate of Clemson University with a Bachelor of Science in Electrical Engineering. In 1990, I received a Master of Business Administration from the University of South Carolina. From 1986 to 2003 I worked for South Carolina Electric & Gas Company ("SCE&G"), now DESC, in various roles in Electric Operations, including Vice President – Wires Operation from 1997-2003. In 2003, I became Vice President – Operations for PSNC and was promoted to President and Chief Operating Officer in January 2006. In 2012, I was named Senior Vice President of SCANA and in 2013 was given additional management responsibilities over SCE&G's Gas Operations. I assumed my current titles after SCANA merged with DEI in January 2019.

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

A. Yes. I presented testimony in each of the Company's last three rate cases, Docket No. G-5, Sub 481, in 2006; Docket No. G-5, Sub 495, in 2008; and Docket No. G-5, Sub 565, in 2016. I also testified in connection with the application requesting authorization for SCANA to merge with DEI, filed in Docket Nos. E-22, Sub 551, and G-5, Sub 585, in June 2018.

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

A. I offer testimony to support the application in this docket, state the need for filing this general rate case, and introduce the Company's witnesses.

Q. PLEASE DESCRIBE PSNC.

A. PSNC was incorporated in 1938 and is a North Carolina public utility engaged in the business of selling, distributing, and transporting natural gas subject to this Commission's jurisdiction. In 2000, PSNC became a wholly-owned subsidiary of SCANA, which merged with DEI in 2019. PSNC currently provides natural gas service to more than 600,000 customers in 96 cities, towns, and their surrounding areas in a service territory that comprises all or parts of 28 counties.

PSNC's territory includes the Raleigh/Durham/Chapel Hill area, the Asheville/Hendersonville area, and the Gastonia/Concord/Statesville area. These areas continue to experience significant growth. The continued stability and relatively low cost of natural gas make our product and service highly desirable to the public in the areas we serve.

Q. PLEASE DESCRIBE THE COMPANY'S SERVICE COMMITMENT.

A. PSNC's service goals are:

- To provide reliable natural gas service while ensuring the safety of the public, PSNC's employees, and its natural gas transmission and distribution system;
- To grow its customer base while encouraging the efficient use of our product; and
- To meet and exceed the expectations of the Company's customers and the public at large.

PSNC embraces the challenge of meeting the strong demand for natural gas in North Carolina, and we are fully committed to doing so in accordance with the policy objectives of the North Carolina General Assembly and the rules and regulations of this Commission. We must operate efficiently in order to keep the delivered cost of natural gas competitive and, in doing so, we strive to meet or exceed our customers' expectations for service. Our customers are increasingly interested in environmental sustainability and we want to help them meet their sustainability goals.

Q. PLEASE DISCUSS THE COMPANY'S COMMITMENT TO SAFETY.

A. Protecting the safety of the public and our employees is our top priority. We work very hard to prevent hazardous occurrences on our system. PSNC has augmented and strengthened its ongoing pipeline safety efforts in response to the transmission and distribution integrity regulations of the federal Department of Transportation's Pipeline and Hazardous Materials Safety Administration

("PHMSA"). These regulations place a great responsibility on the Company and are complex, costly, and evolving. In fact, on July 1, 2020, PHMSA promulgated its "Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments" (commonly referred to as the "Mega Rule"), which is discussed in detail by Company witness Randall. PSNC has conscientiously complied with PHMSA's requirements and, as new regulations are promulgated, will continue to develop and implement measures to operate its system consistent with the new requirements.

PSNC is proud of its damage prevention program results. An effectiveness measure of damage prevention is the damage ratio, which is the number of pipeline damage incidents per thousand locate requests. While the number of requests has increased by approximately 40% since the Company's last test year, our damage ratio has continued to decline. In 2019, PSNC reached an all-time low damage ratio of 1.80, a record that stood for only one year. The damage ratio dropped in 2020 to 1.43, a 20% decrease.

PSNC is also committed to the safety of its employees. The Company measures its employee safety efforts with an industry standard known as the Accident Frequency Rate ("AFR"). AFR represents the number of injuries experienced in relation to the number of employee hours worked. PSNC had only five recordable injuries in 2020 which resulted in our record lowest AFR of 0.82. These results come from proactive measures such as performing field safety audits, sharing lessons learned, benchmarking and implementing best practices, and engaging our employees in improving safety efforts from the frontline to top leadership. Personal protective equipment ("PPE"), procedures, training programs, and technology are constantly evaluated, updated, and implemented to improve our safety performance.

Q. PLEASE COMMENT ON PSNC'S CUSTOMER SERVICE EFFORTS.

A. PSNC listens to its customers and provides services that make it easier for them to do business with us. The Company has implemented several new technology projects, such as our new Dominion App, and made enhancements to our website and interactive voice response system to provide more convenient, self-service options for our customers. PSNC annually exceeds its call center answer rate standard of 80% of calls answered within 20 seconds.

PSNC consistently attains high rankings in third-party customer engagement studies and routinely receives positive feedback in its customer service surveys. Notably, PSNC has not been the subject of a formal complaint at the Commission since 2009.

Q. HAS THE COMPANY EXPERIENCED SIGNIFICANT CHANGES SINCE ITS LAST GENERAL RATE CASE?

A. Yes. Some of the more notable changes include:

- Significant customer growth on PSNC's system
- Completion of the T-1 transmission pipeline project
- Completion of the T-30 transmission pipeline project
- Expansion of pipeline integrity programs in compliance with federal regulations

- SCANA's successful merger with DEI
- Effects of the COVID-19 pandemic

Through all these demanding changes, we have continued to meet our high standards of customer service and our employees have risen to the challenge.

Q. PLEASE ELABORATE ON THE CUSTOMER GROWTH IN PSNC'S TERRITORY.

A. PSNC appreciates its territory's growing customer base and has a strong commitment to serve. In 2020, we passed the milestone of having 600,000 customers on our system, which is more than a 10% increase since our 2016 general rate case. We expect this trend to continue.

Our Asheville/Hendersonville region is one of the top retirement areas in the country. There have been significant business expansions in the Gastonia/Concord/Statesville area, as its proximity to Charlotte contributes to the growth in Gaston, Cabarrus, and Iredell Counties. Corporate relocations and migration continue to fuel customer growth in the Triangle area.

Q. HOW HAS THIS GROWTH AFFECTED PSNC'S OPERATIONS?

A. To serve a growing customer base, PSNC has expanded and strengthened its delivery system and prudently acquired the necessary capacity to meet our customers' needs.

Q. HOW HAS PSNC EXPANDED AND STRENGTHENED ITS SYSTEM?

A. Since the Company's last general rate case, the Company has added more than 60,000 services and more than 1,100 miles of main to its system. PSNC installed these facilities to serve new customers and strengthen its system to provide the additional pressure and capacity required to serve customers reliably. The T-1 project, a significant system expansion project completed in 2018, addressed pipeline integrity findings and provides additional capacity to serve western North Carolina. The T-30 transmission pipeline is a more recent significant system enhancement project.

Q. PLEASE DESCRIBE THE T-1 PROJECT.

A. As a result of assessments performed in 2014 pursuant to its pipeline integrity management program, PSNC identified the T-1 transmission pipeline for replacement. PSNC then increased the size of the replacement pipe and added compression in order to meet future customer growth in its western territory and to provide natural gas services to Duke Energy Progress' Asheville[1] electric generation facility and Duke Energy Carolinas' Rogers Energy Complex[2] electric generation facility. The T-1 pipeline project replaced approximately twenty-five miles of vintage 1950's transmission pipeline through Polk, Henderson, and Buncombe Counties with a new 20-inch pipeline, extended that pipeline approximately three miles to the Asheville generation facility, and added approximately forty-eight miles of new 24-inch transmission pipeline

[1] The Asheville Plant is a new 560-megawatt combined-cycle natural gas plant located in Arden, North Carolina, constructed to accommodate growth in the Ashville area and meet customers' demand. *See* Duke Energy Progress, *Power Plants: Asheville Plant*, Duke Energy Corporation (2021), *available at* https://www.duke-energy.com/our-company/about-us/power-plants/asheville-plant.

[2] The Rogers Energy Complex (formerly Cliffside Steam Station) is a 1,387 megawatt plant located in Cleveland and Rutherford counties. In 2018, natural gas was added to the station, allowing up to 40% natural gas co-firing on one unit and up to 100% on another. *See* Duke Energy Carolinas, *Power Plants: Rogers Energy Complex*, Duke Energy Corporation (2021), *available at* https://www.duke-energy.com/Our-Company/About-Us/Power-Plants/Rogers-Energy-Complex.

through Cleveland, Rutherford, and Polk Counties. Six new natural gas-fired compressors were also installed.

Q. PLEASE DESCRIBE THE T-30 PROJECT.

A. PSNC constructed the T-30 pipeline to meet growth in Franklin and Wake counties. This 38-mile, 20-inch pipeline project is a necessary component of the reliable system required to serve the Raleigh area. Company witness Randall describes the project further in his testimony.

Q. PLEASE ADDRESS THE STATUS OF THE ATLANTIC COAST PIPELINE ("ACP") AND MOUNTAIN VALLEY PIPELINE ("MVP") PROJECTS.

A. The Company originally entered into a precedent agreement in 2014 with ACP to acquire capacity on a pipeline that was scheduled to be in service in late 2018. When completed, the project would have provided the Company with service from a second interstate pipeline, and a direct connection to gas supplies in the Marcellus and Utica shale basins of West Virginia, Pennsylvania, and Ohio. In July 2020, ACP announced that it had cancelled the project due to ongoing delays and increasing cost uncertainty.

The Company entered into precedent agreements with MVP in 2017 to obtain capacity on its mainline pipeline project extending from northwestern West Virginia to Pittsylvania County, Virginia, and on an approximately 70-mile lateral ("MVP Southgate") extending from the termination of the mainline project to PSNC's delivery points. The MVP mainline project is over 90% complete and, while the projected in-service date was delayed from original projections, it is scheduled to be in service by late 2021. The MVP Southgate project is expected to be in service by 2022. The MVP capacity is needed to serve the Company's growing customer base and will satisfy its customers' firm peak-day demand well into the future. The Company's projected capacity requirements indicate a significant shortfall absent the successful completion of the MVP and MVP Southgate projects. Additionally, connecting to this second interstate pipeline will provide supply security and access to gas sourced from the shale regions, which will result in enhanced reliability for customers.

Q. PLEASE DESCRIBE YOUR PIPELINE INTEGRITY EFFORTS.

A. We have diligently kept pace with our transmission and distribution pipeline integrity programs, including adapting to the uncertainty of changing regulations. Pipeline integrity programs have the overall goal of assessing pipeline systems and addressing the identified risks. PSNC has developed plans and is assessing additional miles of its transmission pipelines, enhancing its knowledge and database on these facilities, strengthening its review of in-line inspection ("ILI") data, and remediating the anomalies that PSNC discovers through these assessments. By the end of 2020, PSNC had retrofitted approximately two-thirds of its transmission pipelines to allow for ILI, and had completed ILI on more than one-half of its transmission pipelines.

PSNC must continue to prioritize these programs to comply with federal regulations. Company witness Randall highlights the need for the continuation of the Integrity Management Tracker ("IMT") and the deferral of pipeline integrity operations and maintenance costs.

Q. PLEASE PROVIDE AN UPDATE ON SCANA'S MERGER WITH DEI.

A. SCANA's merger with DEI was effective January 1, 2019, and it has benefitted PSNC and its customers. For example:

- PSNC's access to DEI's centralized service company has resulted in the sharing of best practices across a broader range of service experience, including, among other things, the adoption of new construction procedures to ensure a higher level of environmental performance.
- The merger improved PSNC's access to equity capital through DEI's greater financial resources as evidenced by the two equity infusions that PSNC has received from DEI since the merger. The merger has also positively affected investors' perception of PSNC's creditworthiness as Company witness Phibbs testifies.
- DEI has a strong commitment to sustainability. While PSNC began offering conservation programs in 2009, DEI's holistic approach makes sustainability a more meaningful priority for PSNC. The Company is fully engaged in contributing to DEI's larger goal of carbon neutrality by 2050. To this end, as discussed in the testimony of Company witness Herndon, PSNC proposes to expand its conservation programs and to offer a voluntary program for customers to purchase renewable natural gas attributes, the GreenTherm™ Renewable Natural Gas Program ("GreenTherm™ Program"). Additionally, Company witness Randall testifies regarding the Company's proposal to implement a research and development program.

Q. PLEASE DISCUSS THE COVID-19 PANDEMIC'S EFFECT ON THE COMPANY.

A. This last year has been unlike any other time in the last 100 years, and COVID-19's future impacts and duration are currently unknown. While COVID-19 has tested everyone's resilience, we have continued to provide exceptional service to our customers throughout the pandemic. Governor Cooper declared a state of emergency due to COVID-19 on March 10, 2020. In less than a week, PSNC filed a request with the Commission to suspend service disconnections, waive the application of late payment charges, allow reconnection without a reconnection fee, and waive the requirement for security deposits for disconnected customers.[3] We have also complied with the Commission's subsequent orders regarding the pandemic.

I am also proud of our employees during these trying times. While many employees have been able to work from home, as a natural gas company PSNC still has many employees working in the field every day. Our customer service obligations and primary focus of operating a safe system require that we respond when necessary, such as to investigate gas leaks or to turn services on.

During the early stages of the pandemic, PSNC suspended non-critical customer orders and service disconnections. PSNC worked emergency and turn-on orders, but implemented strict COVID-19 protocols to protect our customers and employees. PSNC also established a Special Purpose Team of

[3] Docket No. G-5, Sub 617.

service employees trained and equipped with PPE to respond to any customer interactions where screening questions indicated there might be COVID-19 exposure risks.

Q. WHY IS A GENERAL RATE CASE NECESSARY AT THIS TIME?

A. PSNC has not had a general rate case in five years. PSNC's current rates are not sufficient to allow the Company to earn a fair return on the significant investments the Company has made extending service to new customers and strengthening and enhancing the safety and reliability of its system. After adjustments to test year data, the Company will have added almost $1.2 billion in utility plant and incurred more than $110.8 million in deferred pipeline integrity expenses since the last general rate case. In that case, the Commission determined a reasonable overall rate of return was 7.53%. After proposed adjustments, the Company's overall rate of return is 5.32%.

Q. WHAT IS THE COMPANY REQUESTING IN THIS CASE?

A. The Company is requesting:

- A revenue increase of approximately $53.1 million
- To continue the IMT
- To continue to amortize and collect deferred transmission and distribution integrity management expenses
- To implement new depreciation rates
- To flow through to customers benefits from federal and state income tax reductions
- To implement a rider to recover conservation program expenses

- To implement the GreenTherm™ Program
- Funding for research and development
- To update and revise certain tariff provisions

Q. PLEASE INTRODUCE THE WITNESSES WHO WILL TESTIFY ON PSNC'S BEHALF.

A. M. Shaun Randall, General Manager of Gas Operations—PSNC will testify to the extension of the IMT, the extension of the deferral of transmission and distribution integrity management expenses, and the Company's request for research and development funding.

Michael B. Phibbs, Director – Corporate Finance and Assistant Treasurer—DEI will testify to the financial status of the Company and the capital markets' view of PSNC.

Jennifer E. Nelson, Assistant Vice President—Concentric Energy Advisors will testify to the reasonableness of the requested return on equity and proposed capital structure.

John D. Taylor, Managing Partner—Atrium Economics, LLC will testify to the Company's cost of service study and rate design.

John J. Spanos, President—Gannett Fleming Valuation and Rate Consultants, LLC will testify to the proposed depreciation rates.

James Herndon, Vice President, Strategy and Planning Practice, Utility Services—Nexant, Inc. will testify to the expanded conservation programs and GreenTherm™ Program.

Byron W. Hinson, Director – Regulation for PSNC—Dominion Energy Services, Inc. will testify to the Company's gas regulatory accounting and proposed changes in rates, tariffs, and rules and regulations.

James A. Spaulding, Manager – Financial & Business Services—PSNC will testify to the Company's rate base, depreciation expense, and other accounting adjustments.

Q. IS THE COMPANY'S REQUEST JUST AND REASONABLE? IF SO, WHY?

A. Yes, it is. As Company witness Nelson explains in her testimony, the requested 10.25% return on equity is reasonable as it will permit the Company to access capital markets and maintain its credit quality, and it is consistent with the returns of businesses with comparable business risk. Company witness Nelson also considered the impacts of changing economic conditions on customers in determining a reasonable ROE.

The Company is not proposing increases to its basic facilities charges, reconnection, or returned check fees. After federal and state tax reduction flow-through described by Company witness Spaulding, the overall proposed increase in rates is 7.27%, which is lower than the rate of inflation since 2016. The average residential customer's monthly bill will increase by approximately $4 if PSNC's request is granted. Due to lower gas costs, the proposed residential winter rate is about 25% less than the same rate following PSNC's 2008 general rate case.

Q. DOES THIS COMPLETE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632

DIRECT TESTIMONY

OF

M. SHAUN RANDALL

APRIL 1, 2021

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

A. My name is M. Shaun Randall and my business address is 800 Gaston Road, Gastonia, North Carolina 28056. I am General Manager of Gas Operations for Public Service Company of North Carolina, Inc., d/b/a/ Dominion Energy North Carolina ("PSNC" or the "Company").

Q. WHAT ARE YOUR RESPONSIBILITIES WITH THE COMPANY?

A. I am responsible for the management of PSNC's operations, including the provision of safe and reliable natural gas sales and transportation services to customers located within its franchised service territory.

Q. PLEASE BRIEFLY OUTLINE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. Following my graduation from Clemson University in 1995 with a Bachelor of Science degree in Civil Engineering, I was employed by PSNC in Gastonia, North Carolina, where I held various positions including Engineer, Operations Supervisor, and Regional Manager. In 2001, I joined South Carolina Electric & Gas Company ("SCE&G"), now known as Dominion Energy South Carolina, Inc., where I served as the Division Manager in both Aiken and Columbia and as the General Manager of Gas Operations. In 2014, I accepted the position of Vice President of Gas Services for SCANA Services, Inc., where I led the engineering and operational support services for both PSNC and SCE&G. In September 2018, I assumed my current role as the General Manager of Gas Operations at PSNC. In this role, I am responsible for the management of PSNC's operations, including the provision of safe and reliable natural gas sales and transportation services to customers located within its franchised service territory. I am a licensed Professional Engineer in both North Carolina and South Carolina.

Q. HAVE YOU PREVIOUSLY TESTIFIED BEFORE THIS COMMISSION?

A. No, I have not. However, I have testified on behalf of SCE&G before the Public Service Commission of South Carolina in purchased gas adjustment proceedings in Docket Nos. 2012-5-G and 2013-5-G.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony describes: (1) the Company's capital investment since its last general rate case in 2016; (2) the Company's transmission pipeline integrity management program ("TIMP") and distribution integrity management program ("DIMP"); (3) the regulations that govern the TIMP and DIMP; (4) the need for the extension of the Integrity Management Tracker ("IMT") to recover capital expenses related to the TIMP and DIMP; (5) the need for the continuation of regulatory asset accounting treatment for certain operations and maintenance ("O&M") expenses incurred in connection with the TIMP and DIMP; (6) the Company's T-30 pipeline project; and (7) the Company's proposal to fund research and development ("R&D") efforts.

I. PSNC'S CAPITAL INVESTMENT

Q. PLEASE DISCUSS PSNC'S CAPITAL INVESTMENT SINCE ITS LAST GENERAL RATE CASE.

A. Since its last general rate case in 2016, PSNC projects that it will have almost $1.2 billion of additional plant in service by June 30, 2021, comprised of the following:

- Excluding integrity management related plant, an additional $723 million in transmission and distribution plant, of which $170 million is in the T-30 pipeline project. PSNC made these investments to provide for customer growth and the continued reliability of its system, as discussed in Company witness Harris's testimony.
- $450 million in additional integrity management plant. PSNC made these investments to comply with federal pipeline safety regulations.
- $16 million in other additional plant investments, including liquefied natural gas facility capital improvements, intangible plant, and general plant additions.

I will discuss the Company's integrity management programs and T-30 project more fully below.

II. PIPELINE INTEGRITY MANAGEMENT

Q. PLEASE BRIEFLY DESCRIBE PSNC'S INTEGRITY MANAGEMENT EFFORTS.

A. PSNC has multiple processes to ensure the safety of its natural gas transmission and distribution systems. These processes include identifying and assessing risks on its transmission and distribution pipelines and remediating conditions that present potential risks to pipeline integrity. PSNC has escalated its integrity management efforts as federal pipeline safety regulations have evolved and expanded.

Q. PLEASE DESCRIBE THE FEDERAL REGULATIONS PERTAINING TO TRANSMISSION AND DISTRIBUTION PIPELINE INTEGRITY MANAGEMENT.

A. The federal regulations that govern pipeline safety for natural gas utilities are administered by the U. S. Department of Transportation's ("USDOT") Pipeline and Hazardous Materials Safety Administration ("PHMSA") and the state utilities commissions are charged with ensuring compliance with the regulations. The TIMP and DIMP regulations are within Subparts O and P, respectively, of Part 192, Title 49, of the United States Code of Federal Regulations.

TIMP regulations were prompted by the enactment of the Pipeline Safety Improvement Act in 2002, which required, among other things, that operators of natural gas transmission pipelines implement integrity management programs conforming to regulations promulgated by the USDOT. The USDOT's Office of Pipeline Safety, which is now a part of PHMSA, published the Gas Transmission Rule in late 2003.

DIMP regulations were prompted by the enactment of the Pipeline Integrity, Protection, and Safety Act in 2006, which directed PHMSA to prescribe minimum standards for integrity management programs applicable to natural gas distribution systems. In December 2009, PHMSA published the "Pipeline Safety: Integrity Management Program for Gas Distribution Pipelines" Rule.

On October 1, 2019, PHMSA formally released Part 1 of its Safety of Gas Transmission Pipelines rule ("Mega Rule"), which revised the transmission pipeline integrity management regulations, with an initial effective date of July 1, 2020. PHMSA subsequently delayed the effective date until December 31, 2020, due to the global pandemic. Some sections of the rule are not effective until July 1, 2021. The Mega Rule is broad in scope, and applies to operations, maintenance, and engineering.

Q. PLEASE DESCRIBE THE MOST SIGNIFICANT PROVISIONS OF THE MEGA RULE.

A. The most significant areas of change in the Mega Rule relate to the following:

- Expansion of Integrity Management outside of High Consequence Areas ("HCAs") – Creates a new classification of Moderate Consequence Area ("MCA") and requires pipelines operating at 30% or greater specified minimum yield stress and located in certain MCAs to be assessed similarly to pipelines in HCAs.
- Material Verification ("MV") – In areas where records are not traceable, verifiable, and complete ("TVC"), or are based on assumed properties, operators are now required to conduct an MV program where excavations are checked for records quality.

- Maximum Allowable Operating Pressure ("MAOP") Reconfirmation – Where TVC pressure test records are lacking or MAOP was established via the "grandfather clause" in the PHMSA regulations, operators are required to reconfirm the MAOP of the pipeline by (1) taking the pipeline out of service to pressure test, (2) significantly reducing the operating pressure, (3) performing an engineering critical assessment, or (4) replacing the pipeline.

In addition to the above, the Mega Rule imposes new requirements regarding threat identification, spike testing, launcher/receiver safety, fracture mechanics, and records.

Q. WHAT IS THE PRACTICAL EFFECT OF THE TIMP AND DIMP REGULATIONS?

A. The regulations' objectives are to ensure that pipeline operators know their assets, identify the threats and risks to their assets, and proactively mitigate those threats and risks. The TIMP regulations are very prescriptive and, as such, have specific requirements for how pipeline operators must identify, prioritize, assess, evaluate, repair, and validate the integrity of gas transmission pipelines that could, in the event of a leak or failure, affect HCAs. While the DIMP regulations are not as prescriptive and allow each operator to develop its own DIMP, each operator must meet the objectives of its plan in order to comply. The DIMP regulations require that operators implement a DIMP that demonstrates the operator's knowledge of the distribution system, identifies threats and risks, evaluates and ranks risks, identifies and implements measures to address those risks, measures performance, monitors results, periodically evaluates and improves the program, and reports results.

Q. WHAT WILL BE THE IMPACT OF THE MEGA RULE ON PSNC?

A. The Mega Rule may require additional assessments of a hundred or more miles of transmission pipelines, the use of new testing technology requirements for all pipeline excavations, and the derating, retesting, or replacement of pipelines.

As only Part 1 of the Mega Rule has been released, there are additional requirements yet to be imposed by PHMSA. Those requirements are expected to include new requirements in external and internal corrosion control, criteria for pipeline repairs, risk and threat evaluation, and preventative and mitigation measures. PSNC continues to evaluate these Mega Rule requirements, and they are likely to cause PSNC to increase its integrity management budget.

Q. PLEASE PROVIDE AN OVERVIEW OF PSNC'S TIMP COMPLIANCE.

A. Consistent with its TIMP, PSNC has:

- Retrofitted pipelines, where feasible, to accept in-line inspection ("ILI") tools or other "smart pig" technology, utilized that technology on those lines, and performed inspections with robotic tools on short sections of lines that were previously considered "non-piggable." Currently more than two-thirds of PSNC's transmission pipelines are "piggable."
- Implemented Mechanical Damage Direct Assessment inspections to address specific threats and risks to approximately 160 miles of transmission pipelines located in road rights-of-way. In 2020, PSNC completed these inspections, after conducting more than 3,000 excavations.

Approximately 10% of the excavations revealed damages to the pipe or coating, which were subsequently remediated.

- Replaced or derated the pipelines or pipeline segments listed below from transmission to distribution pressure. Lowering the pressure on these pipelines to distribution pressure improves their safety and removes them from the Company's TIMP, thereby reducing ongoing compliance costs.
    - T-18 (13 miles of 1950's vintage 4-inch transmission pipeline) via the installation of T-18B.
    - T-24 (36 miles of 1950's vintage 8-inch road shoulder transmission pipeline) via the installation of M-68.
    - T-1 (7 miles of 1950's vintage 8-inch transmission pipeline) and T-4 (13 miles of 1950's vintage 8-inch and 12-inch transmission pipeline) via the installation of M-64.
    - T-63 (12 miles of 1980's vintage 12-inch road shoulder transmission pipeline through a highly congested and growing area) via the installation of T-30, as mentioned later in my testimony.
- Identified HCAs and now, due to the Mega Rule, MCAs. PSNC is currently upgrading its Geographic Information System ("GIS") and developing new modules that will allow the Company to identify and calculate the MCAs in addition to the previously required HCAs.
- Identified threats for each of the covered segments (HCAs) and assessed the risks to those segments.

- Updated PSNC's threat and risk procedures to align with the PHMSA advisory bulletins on threat inactivation and include changes to comply with the Mega Rule.
- Developed a threat summary report for each transmission pipeline that includes summary findings based on assessments, integrates data on materials and findings, and provides guidance on proper assessment method and tool selection for given threats.
- Performed third-party review of risk analyses to benchmark legacy risk analyses against upgraded algorithms based on Mega Rule changes and created a baseline assessment plan based on the results to determine the integrity of the segments.
- Developed an alternating current corrosion screening procedure and performed system analysis to determine areas of higher risk and potential alternating current modeling studies.
- Performed the required assessments (ILI, direct assessment, and pressure test) at prescribed intervals to ensure proper evaluation of system integrity.
- Conducted more frequent aerial patrols to mitigate the threat of third-party damage.
- Mitigated or repaired flaws and defects as anomalies are detected. These anomalies include dents, corrosion damage, material flaws, construction flaws, coating flaws, and areas of cathodic protection deficiency.

Q. PLEASE PROVIDE AN OVERVIEW OF THE COMPANY'S DIMP COMPLIANCE.

A. PSNC evaluates threats to its distribution system and implements measures to reduce those threats through direct actions on the system, public awareness communications, damage prevention efforts beyond locating, enhanced technologies, and improved procedures. DIMP activities include the following:

- Inspections/Practices – These direct actions address real-time threats to the distribution system and include:
    - Sewer cross-bore inspections – PSNC evaluates sewer mains and laterals to determine whether or not gas lines have been installed through them.
    - Facilities locating – High customer growth on PSNC's system and fiber optic cable and other communication installations have increased locate requests by approximately 40% since 2015. PSNC uses third-party contractors to supplement internal resources to ensure quality locates and damage prevention.
    - Other direct actions for specific risks include identifying and protecting stations and meter sets from vehicle damage, identifying and replacing components prone to failure, and addressing the location of pipelines and services that are difficult to locate through traditional methods.
- Enhanced Cathodic Protection on System – These actions address corrosion risks and improve corrosion protection on pipeline facilities and include:

    - New technologies and data systems that increase the information available regarding the status of cathodic protection systems.
    - Other direct actions for specific risks include inspecting and remediating the ground/pipe interface at station risers and meter sets, meter painting programs, adding additional test stations, replacing anodes on steel systems, addressing isolated services, and installing rectifiers.

- Safety Communications/Public Awareness – PSNC raises the general public's and contractors' awareness of pipeline safety through:
    - Public awareness communications using traditional means such as newspaper advertisements, mail, and signage.
    - Communications using digital means such as websites, safety banners to redirect viewers to more information, and Facebook pages.
    - Communications aimed at third-party damage reduction and other safety messaging using billboards, signage, and radio and TV advertisements.
- Damage Prevention
    - Locate Ticket Risk Model/Advanced Ticket Management – PSNC uses systems and data to evaluate risks on locate tickets and direct the appropriate mitigating actions based on the risk identified.

- Excavator Field Audits/Inspections/Locate Ticket Quality Assurance – PSNC uses a variety of measures to ensure the quality of damage prevention efforts and locating performance.

- Enhanced Distribution Integrity Technology/Data Integration – PSNC uses technology to gather additional pipeline attribute data for use in its GIS, risk models, and engineering system. PSNC is initiating the following:
    - Mapping of services in GIS by reviewing more than 600,000 service records and entering them in GIS to provide more accurate information to the field for locating, leak surveying, and routine maintenance.
    - Validating distribution MAOP through an extensive records review, substantial field and laboratory investigations, and implementation of technology.
- Pipeline Safety Management System – PSNC evaluates and implements changes in regulations as well as reinforces and expands pipeline safety management system communications, including:
    - Conducting comprehensive third-party reviews of integrity related procedures to ensure that they are consistent and have robust change management practices.
    - Auditing the DIMP, which involves data gathering, reviewing best practices, verifying processes, reviewing risk ranking, and revising as needed.

Q. SINCE THE COMPANY'S JUNE 30, 2016 UPDATE IN THE LAST GENERAL RATE CASE, HOW MUCH PLANT HAS PSNC ADDED IN CONNECTION WITH ITS TIMP AND DIMP EFFORTS?

A. PSNC will have invested approximately $450 million through June 30, 2021. Of that, approximately $338 million is or will be subject to recovery through the IMT, leaving a balance of approximately $112 million to be included in PSNC's rate base as proposed in this case.

Q. HOW MUCH HAS PSNC BUDGETED FOR FUTURE COMPLIANCE?

A. For the period of July 1, 2021, through December 31, 2024, PSNC has budgeted approximately $166 million in capital expenditures to support these programs.

Q. HOW CERTAIN IS THE COMPLIANCE BUDGET?

A. By their nature, the integrity management programs are capital intensive and difficult to plan and budget for. PSNC cannot predict with certainty the number of anomalies that the Company might discover on its pipeline system. The Company also cannot project the cost of remediating the anomalies that might be discovered. PSNC also cannot predict the cost of complying with future requirements of the Mega Rule or with other regulations that PHMSA might promulgate.

III. THE INTEGRITY MANAGEMENT TRACKER

Q. WHAT IS THE IMT?

A. The IMT is a cost recovery mechanism that allows PSNC to recover the capital costs of its TIMP and DIMP projects until the Company's next general rate case. Details of each project, its costs, and the accounting for such costs are included in PSNC's biannual and monthly compliance reports filed in Docket No. G-5, Sub 565C.

Q. PLEASE BRIEFLY DESCRIBE THE PROCEDURAL HISTORY OF PSNC'S IMT.

A. Pursuant to N.C. Gen. Stat. § 62-133.7, the Commission granted PSNC the authority to implement the IMT in its last general rate case in Docket No. G-5, Sub 565. That authorization was for four years or the Company's next general rate case, whichever came earlier; that authorization was to expire on October 28, 2020. In June 2020, PSNC filed an application with the Commission to extend the IMT for two years or until the Company's next general rate case, whichever came earlier. The Commission issued an Order on August 10, 2020, extending the IMT and postponing the review for two years or until the Company's next general rate case, whichever came earlier.

Q. PLEASE DESCRIBE THE PROCEDURAL HISTORY OF PSNC's TIMP AND DIMP DEFERRALS.

A. In 2005, the Commission granted PSNC's request to defer the O&M expense associated with TIMP in Docket No. G-5, Sub 459. The Commission subsequently authorized cost recovery of these deferred expenses in PSNC's 2006, 2008, and 2016 general rate cases in Docket Nos. G-5, Sub 481, G-5, Sub 495, and G-5, Sub 565, respectively. In 2016, the Commission granted PSNC's request in Docket No. G-5, Sub 565 to defer the O&M expense association with its DIMP.

Q. IS PSNC REQUESTING AUTHORIZATION TO EXTEND ITS IMT AND TIMP AND DIMP DEFERRALS?

A. Yes. PSNC is requesting authority to extend the IMT and is not requesting to modify any of its provisions other than the expiration date. PSNC is also requesting to continue the deferral of TIMP and DIMP O&M costs.

Q. WHY IS IT APPROPRIATE FOR THE COMMISSION TO GRANT PSNC'S REQUESTS?

A. The reasons that originally caused PSNC to request approval of these mechanisms, as well as the extension of the IMT, are just as relevant today. The Company's TIMP and DIMP are expensive and mandated by federal regulations, which are continuing to evolve. The IMT mechanism and the deferrals are extremely important because they ensure PSNC's ability to timely invest in and earn on the significant expenditures, which avoids the need for multiple general rate cases to recover these costs.

IV. PSNC'S T-30 PROJECT

Q. PLEASE DESCRIBE THE T-30 PROJECT.

A. The T-30 project is a new 20-inch diameter transmission pipeline that spans 38 miles from Franklinton to Clayton. It provides a loop around the eastern side of Raleigh with new regulating stations feeding into PSNC's distribution system. The pipeline is necessary to support regional growth and improve system reliability. It will provide the capacity to supply natural gas to an additional 50,000+ homes in the largest and fastest growing area of PSNC's territory. The project will also support transmission integrity initiatives by allowing the Company to reduce the operating pressure on T-63 from transmission to distribution pressure.

Q. PLEASE ELABORATE.

A. The Raleigh area was originally served by a single pipeline, T-21, which was installed in 1952. In 1994, Cardinal Pipeline constructed a 24-inch pipeline that provided another delivery point to PSNC's system on the southeast side of Raleigh and Wake County. T-30 receives gas supply from Transcontinental Pipe Line at the Company's Dan River take-off station in Alamance County and runs to an interconnect with the Cardinal Pipeline in southeast Wake County. This arrangement will free up the Company's capacity on the Cardinal Pipeline that can be allocated to other supply points and will allow PSNC to serve customers in Wake County who previously would have been served from PSNC's Cardinal Pipeline supply. In this manner, this new interconnection will improve resiliency and supply security for that part of PSNC's system.

Q. WHAT IS THE ESTIMATED COST OF T-30?

A. T-30 is projected to cost approximately $175 million, of which approximately $170 million will be included in plant in service as of June 30, 2021. Since the Company's last general rate case, the T-30 project is one of PSNC's largest capital investments.

V. RESEARCH AND DEVELOPMENT

Q. PLEASE DISCUSS PSNC'S PROPOSED R&D EFFORTS.

A. PSNC is emphasizing R&D because customers and other stakeholders are increasingly expecting the Company to support a cleaner environment. Further, Dominion Energy, Inc. has announced the goal of net zero emissions by 2050, and the Company is committed to contributing to that goal. PSNC is increasing its focus on new and innovative solutions to meet stakeholder interests and sustainability goals.

The Company proposes to study the effects of blending hydrogen with natural gas to determine its safety and viability. For example, the Company needs to determine the impact of using blended hydrogen on leak detection and other safety considerations. The Company also needs to determine the level of hydrogen that can be blended without negatively affecting the Company's system and end-users' appliances. PSNC plans to conduct testing at its training facilities, concentrating on gas measurement, regulation equipment, distribution piping, and end-user residential appliances. This initiative will broaden the Company's overall understanding of the feasibility of using hydrogen as an alternative fuel source, including the study of hydrogen's availability, pricing, and storage.

The Company will also focus its R&D efforts on renewable natural gas ("RNG"). RNG is a carbon-negative fuel because the capture of methane in RNG production more than offsets the carbon dioxide emissions of its combustion. As such, the availability of robust RNG supplies could significantly facilitate the achievement of the Company's sustainability goals. PSNC's proposed GreenTherm™ Program is a significant first step toward providing its customers the opportunity to purchase RNG attributes. However, the Company does not currently have the resources to explore fully the potential of RNG to meet its customers' and the Company's sustainability goals. PSNC plans to assess the various technologies, markets, and opportunities to expand and develop RNG availability for its customers.

Company witness Spaulding proposes adjustments to fund these initiatives.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632

DIRECT TESTIMONY

OF

MICHAEL B. PHIBBS

APRIL 1, 2021

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

A. My name is Michael B. Phibbs, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am the Director – Corporate Finance and Assistant Treasurer for Dominion Energy, Inc. ("DEI") and subsidiaries including Public Service Company of North Carolina, Inc. ("PSNC" or the "Company"). I am employed by Dominion Energy Services, Inc.

Q. PLEASE DESCRIBE YOUR EDUCATION AND BUSINESS BACKGROUND.

A. I have two bachelor's degrees in finance and economics from Virginia Polytechnic Institute and State University, and a master's degree in business administration from the University of Florida. I joined DEI in 2006 within the Mergers & Acquisitions group as an Associate Financial Analyst and held increasing responsibilities until I was promoted to Manager – Merger & Acquisitions in 2015. In 2017, I assumed the role of Manager – Corporate Finance primarily overseeing capital markets activities and became Director – Corporate Finance and Assistant Treasurer in January 2020.

Q. WHAT ARE YOUR PRIMARY JOB RESPONSIBILITIES?

A. My responsibilities include formulating strategies to ensure that the Company can meet its capital requirements at a reasonable cost and accessing capital markets and executing on related financing transactions for the Company. In this capacity, I also oversee interest rate risk management, manage the

Company's relationships with lenders, and play a key role in liaising with credit rating agencies.

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

A. The purpose of my testimony is to provide an overview of the financial status of the Company as it relates to the decision to seek rate relief at this time. I will discuss the importance and need of the Company's requested rate increase given PSNC's continued need to access capital on favorable terms. My testimony presents PSNC's actual year-end regulated capital structure as of December 31, 2020, and the Company's proposed capital structure for use in this case. I also discuss the Company's credit profile and the importance of maintaining strong credit ratings as it continues to make capital investments in its natural gas assets for the benefit of PSNC's customers. Within that context, I detail the emphasis from rating agencies placed on constructive regulatory environments and outcomes within their analysis.

Finally, I address how the Company's capital spending and future needs should be considered in determining PSNC's overall cost of capital and proposed return on equity ("ROE"). Just and reasonable ratemaking helps to ensure steady access to capital markets on reasonable terms across differing economic cycles which benefits customers.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED CAPITAL STRUCTURE TO BE USED IN THIS PROCEEDING.

A. The Company's ratemaking capital structure presented for this proceeding is based upon PSNC's projected capital structure as of June 30, 2021. The capital structure presented follows the Commission's accepted practice for reporting the capital structure including customary adjustments. As shown on Hinson Direct Exhibit 11, the long-term debt component of PSNC's projected capital structure as of June 30, 2021, is 43.79%, and the equity component is 54.88%. The short-term debt figure reflects the estimated 13-month average of gas inventory ending June 30, 2021, consistent with the Commission's practice, and is 1.33%. The long-term debt cost rate is based upon debt issued, in the capital markets, and still outstanding at December 31, 2020, as adjusted to reflect subsequent maturities and issuances through June 30, 2021. The cost of common equity component is supported by Company witness Nelson in her testimony and supporting schedules.

Q. WHAT CAPITAL NEEDS DO YOU FORESEE FOR THE COMPANY?

A. Since its 2016 general rate case, the Company has made significant investments to meet customer growth and to maintain and improve the sustainability and reliability of the service it provides to its customers. The Company plans continued capital investments approximating $630 million during the three-year period 2021-2023 and will need to maintain reasonable access to capital in order to fund these investments.

Q. PLEASE EXPLAIN HOW THE COMPANY'S FINANCING PLANS ARE DEVELOPED.

A. In developing its financing plans, PSNC seeks to balance its financing needs in order to fund operations to meet its public service obligations and to achieve credit ratings objectives, which enable the Company to maintain market access at reasonable terms. In doing so, multiple factors are monitored on a current and projected basis to help inform decisions on equity and debt financing. PSNC's cash coverage position is one factor of importance in credit rating evaluation and is measured primarily by the ratio of funds from operations ("FFO") to total debt ("FFO/Debt"). Another factor is the more familiar total debt to total capitalization ratio ("Debt/Cap") as displayed in a company's capital structure statement. The Company views that it is in all stakeholders' interest for the Debt/Cap figure to be reasonably consistent over time. The overall intent of viewing financing metrics on a forward-looking basis is to further PSNC's goal of achieving its target ratings in a deliberate and consistent manner, while ensuring ratios such as Debt/Cap reflect longer-term stability. The Company views this outcome as constructive in maintaining continued strong investment grade credit ratings and achieving fair and predictable returns. These dual outcomes aid the Company in seeking capital from investors at attractive rates, which ultimately benefit customers.

Q. WHAT ARE THE COMPANY'S CURRENT TARGET CREDIT RATIOS?

A. The Company does not target specific credit ratios; rather, it emphasizes achieving strong investment grade credit ratings. As previously mentioned, we monitor ratios such as FFO/Debt in the context that the ratios would be conducive to the achievement of the Company's credit ratings. It is our view that investors rely most on credit ratings, as opposed to ratios, to assess the creditworthiness of a company to aid investment decisions and expected returns on their capital. Each rating agency has unique criteria for achieving a rating. These criteria include numerous quantitative factors, such as financial ratios, as well as qualitative factors such as regulatory climate that are reviewed holistically by the agencies. The Company is in frequent dialogue with Moody's Investor Service ("Moody's"), Standard & Poor's ("S&P"), and Fitch Ratings Inc., and closely monitors ratings at each agency based on historical results and forecasted projections.

Q. HOW DO THE RATING AGENCIES VIEW REGULATORY OUTCOMES IN THEIR ASSESSMENTS OF A COMPANY'S CREDITWORTHINESS?

A. In short, agencies place a high importance on regulatory outcomes. In order to access capital as needed, the Company must continuously maintain a strong credit profile, balance sheet, and cash flow coverages to ensure that cash flows are sufficient to service debt and to realize adequate returns on equity. To achieve these goals, the Company needs appropriate rate determinations and correlated supportive regulatory decisions, including from this Commission. In its current rating methodology, S&P notes that a supportive legislative and regulatory framework is a critical aspect that underlies regulated utilities' creditworthiness because "it defines the environment in which a utility operates and has a significant bearing on a utility's financial performance." S&P also names "Four Pillars" that provide the foundation of regulatory support. These four pillars include regulatory stability, efficiency of tariff setting procedures, financial stability, and regulatory independence. S&P notes that the utility's business strategy and the tariff-setting process are also important aspects in the overall regulatory assessment. As Moody's noted in a report on its ratings methodology for utilities published in June 2017, it uses four "Broad Rating Factors" in its ratings analysis. The first factor, "Regulatory Framework," carries a 25% weight, including a component for "Consistency and Predictability of Regulation." The second broad factor, "Ability to Recover Costs and Earn Returns," is also given a 25% weight. This factor is split evenly into two sub-factors, "Timeliness of Recovery of Operating and Capital Costs" and "Sufficiency of Rates and Returns." These first two broad functions carry an overall sum of 50% of ratings determination and are directly related to regulatory environment and regulatory supportiveness. Clearly, regulatory support will continue to be of vital importance in determining credit ratings and in turn influence investors' decisions on whether to participate in providing capital to the Company. Investors are attuned to the Company's financial results and to regulatory commission decisions and will respond immediately when the Company's prospects for future returns are perceived to have diminished. A decision from this Commission that sets a return lower than what the market views as adequate would lead credit analysts and investors to conclude that this lower return could be the norm of the regulatory process and make it more difficult for PSNC to secure the capital needed to continue to meet customers' demand for natural gas. This in turn could lead to more expensive financing costs for the Company and, ultimately, customers.

Q. HOW SHOULD THE COMMISSION BALANCE PSNC'S CAPITAL NEEDS WITH THE IMPACT OF CHANGING ECONOMIC CONDITIONS IN SETTING THE COMPANY'S COST OF CAPITAL, AND SPECIFICALLY ITS ROE?

A. As I previously detailed, fair and reasonable regulatory outcomes with respect to capital structure and ROE are integral to providing cash flows that enable the Company to acquire capital at competitive rates from investors to invest in infrastructure to serve customers. Since the last general rate case, the Company will have added almost $1.2 billion of plant in service through June 30, 2021, to support safety, growth, and the continued reliability of the system. We are now seeking recovery of those reasonably incurred costs. As Company witness Harris demonstrates, the Company is requesting a modest rate increase to customers in relation to the capital spent since the last general rate case. This increase is based on the aforementioned capital structure presented and reasonable ROE sought. ROE reasonableness will be further detailed by Company witness Nelson. Equity and debt markets both saw severe disruptions during the COVID-19 pandemic in 2020, with greater volatility and at times a lack of ready access to capital. Generally speaking, in periods of volatility like those experienced in the first half of 2020 there tends to be a "risk-off" mentality within investors in the capital markets which has them seeking out stable and predictable businesses for which to place their dollars. Multiple utility issuers marketed potential debt transactions during the COVID-19 pandemic only to have them withdrawn due to lack of sufficient demand, or greatly increased costs, causing companies great consternation on how to fund their businesses. DEI and PSNC each maintained access to capital at all periods during the market disruption brought on by the pandemic. In our view, this was in large part due to the perceived fair and predictable nature of the regulatory jurisdictions in which they operate, enabling investment recovery and cash generation of the utility businesses underlying DEI as a parent, and PSNC in particular. Last year was a stark reminder that fair and predictable regulatory outcomes enhance the ability to attract adequate capital at a reasonable cost.

Q. DO YOU HAVE ANY FINAL COMMENTS ABOUT YOUR TESTIMONY?

A. The Company will continue to see increased competition for capital in the near future at the same time as it continues with the capital investment plan I have highlighted here. Capital markets have been more volatile in the recent near term than they were during the Company's 2016 general rate case and, under such circumstances, the financial strength and future earnings potential factor even more significantly into the Company's ability to compete for capital. It is vitally important that PSNC be able to achieve a favorable credit profile in order to access equity and debt capital markets on reasonable economic terms and, as a result, be able to make needed capital investments over the next few years to maintain and improve service to its customers. A financially sound natural gas utility with a strong credit profile is in the best interest of both the Company and its customers.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, it does, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 623

DIRECT TESTIMONY

OF

JOHN D. TAYLOR

APRIL 1, 2021

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John D. Taylor and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926.

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

A. I am appearing on behalf of Public Service Company of North Carolina, Inc. ("PSNC" or the "Company").

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

A. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner.

Q. HAVE YOU PREPARED AN APPENDIX DESCRIBING YOUR PROFESSIONAL QUALIFICATIONS?

A. Yes. Appendix A to my direct testimony presents my professional qualifications.

Q. WHAT WAS ATRIUM'S ASSIGNMENT IN THIS PROCEEDING?

A. PSNC requested Atrium to conduct a fully-allocated Cost of Service Study ("COSS") to determine the embedded costs of serving the Company's gas distribution customers and support its rate design efforts. In this regard, I am sponsoring the COSS that allocates PSNC's gas distribution costs to its rate classes, class revenue increase apportionment, and proposed rate design.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. In my testimony I present PSNC's COSS and discuss its results, present the revenue increase apportionment to PSNC's rate classes and present the rate design proposals filed by PSNC in this proceeding. I am also sponsoring

G-1 Item 3 (a), (b), and (d) (referred to as "G-1 Item 3 – COSS") which contains the results of the COSS model, the revenue targets by class, rate design proposals, and further details on the special studies utilized in the COSS. My testimony consists of this introduction and summary section and the following additional sections:

- Purpose and Principles of Cost Allocation
- PSNC's COSS
- Principles of Sound Rate Design
- Determination of PSNC's Proposed Class Revenues
- PSNC's Rate Design

II. PURPOSE AND PRINCIPLES OF COST ALLOCATION

Q. WHAT IS THE GENERAL PURPOSE AND USE OF A COSS IN REGULATORY PROCEEDINGS?

A. The purpose of a COSS is to allocate the gas distribution utility's overall adjusted test year costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. A COSS represents an attempt to analyze which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop a COSS results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more rate classes, or the cost of providing multiple products to the same rate class, use the same facilities and the use by one rate class precludes the use by another rate class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of gas throughput, while variable costs change directly with changes in gas throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains, service lines, meters, and regulators.

Finally, the COSS provides different contributions to the development of economically efficient rates and the cost responsibility by rate class. This is accomplished through analyzing costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each rate class to help determine the individual class revenue responsibility and provide guidance with rate design. Using the cost information per unit of demand, customer, and energy developed in the COSS to understand and quantify the allocated costs in each rate class is a useful step in the rate design process to guide the development of rates.

Q. IS THE PREPARATION OF A COSS AN EXACT SCIENCE?

A. No. The fundamental purpose of a COSS is to aid in the design of rates to be charged to customers by identifying all of the capital and operating costs incurred by the utility to provide service to all of its customers, and then assigning or allocating those costs to individual rate classes on the basis of how those rate classes cause the costs to be incurred. Due to the existence of common costs, this process inherently requires a substantial level of judgment and can be more accurately described as engineering/accounting art, rather than science. The allocation of costs using a COSS is a practical requirement of utility regulation since rates are based on the cost of service for the utility under a cost-based regulatory model. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing revenues that equate to the level of the revenue requirement.

Q. IS THERE A GUIDING PRINCIPLE THAT SUPPORTS THE APPROPRIATE ALLOCATION OF COSTS?

A. Although there may not be a perfect methodology for allocating costs, there is a fundamental foundational principle, cost causation, which should be followed in order to produce more accurate and reasonable results. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs so the analysis results in an appropriate allocation of the utility's total revenue requirement among the various rate classes. In other words, the costs assigned or allocated to particular customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. HOW DO YOU ESTABLISH THE COST AND UTILITY SERVICE RELATIONSHIPS?

A. An important element in the selection and development of a reasonable COSS allocation methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics on the one hand and the costs incurred by the Company in serving those requirements on the other hand. In order to accomplish this, I reviewed PSNC's expense and plant accounts, operational data, usage information, and conducted interviews with PSNC employees. The details and data gathered provided information on the key factors that cause the costs to vary and supported studies of the relative costs of providing facilities and services for each rate class. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for all of the utility's plant and expense elements.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY THE TERM "DIRECT ASSIGNMENT."

A. The term direct assignment relates to a specific identification and isolation of plant and/or expense incurred exclusively to serve a specific customer or group of customers. Direct assignments best reflect the cost causation characteristics of serving individual customers or groups of customers. Therefore, in performing a COSS, the analyst seeks to maximize the amount of plant and expense directly assigned to a particular customer group to avoid the need to rely upon other more generalized allocation methods. An alternative to direct assignment is an allocation methodology supported by a special study as is done with costs associated with meters and services.

Q. WHAT PROMPTS THE ANALYST TO ELECT TO PERFORM A SPECIAL STUDY?

A. When direct assignment is not readily apparent from the description of the costs recorded in the various utility plant and expense accounts, then further analysis may be conducted to derive an appropriate basis for cost allocation. For example, in evaluating the costs charged to certain operating or administrative expense accounts, it is customary to assess the underlying activities, the related services provided, and for whose benefit the services were performed.

Q. HOW DO YOU DETERMINE WHETHER TO DIRECTLY ASSIGN COSTS TO A PARTICULAR CUSTOMER OR RATE CLASS?

A. Direct assignments of plant and expenses to specific customers or classes of customers are made on the basis of special studies wherever the necessary data are available. These assignments are developed by detailed analyses of the utility's maps and records, work order descriptions, property records, and customer accounting records. Within time and budgetary constraints, the greater the magnitude of cost responsibility based upon direct assignments, the less reliance need be placed on common plant allocation methodologies associated with joint use plant.

Q. IS IT REALISTIC TO ASSUME THAT A LARGE PORTION OF THE PLANT AND EXPENSES OF A UTILITY CAN BE DIRECTLY ASSIGNED?

A. No. The nature of utility operations is characterized by the existence of common or joint use facilities, as mentioned earlier. Out of necessity, then, to the extent a utility's plant and expense cannot be directly assigned to customer groups, common allocation methods must be derived to assign or allocate the remaining costs to the rate classes. The analyses discussed above facilitate the derivation of reasonable allocation factors for cost allocation purposes.

Q. WHAT ARE THE STEPS TO PERFORMING A COSS?

A. In order to establish the cost responsibility of each customer class, initially a three-step analysis of the utility's total operating costs must be undertaken. The three steps that are the basis to conduct a COSS are: (1) cost functionalization; (2) cost classification; and (3) cost allocation.

Q. PLEASE DESCRIBE COST FUNCTIONALIZATION.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. PSNC's primary functional cost categories associated with gas service include: gas supply, storage, transmission, distribution, onsite and metering, and customer accounts and service. Indirect costs that support these functions, such as general plant and administrative and general expenses, are allocated to functions using allocation factors related to plant and/or labor ratios; i.e., internal allocation factors.

Q. PLEASE DESCRIBE COST CLASSIFICATION.

A. The second step, cost classification, further separates the functionalized plant and expenses according to the primary factors that determine the amount of costs incurred. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the gas distribution system; and (3) the amount of gas consumed by customers. These classification categories have been identified for purposes of the COSS as: (1) customer costs; (2) demand costs; and (3) commodity costs, respectively.

Q. PLEASE DESCRIBE THE TYPES OF COSTS CONTAINED IN THE CUSTOMER COST, DEMAND COST, AND COMMODITY COST CATEGORIES.

A. Customer-related costs are incurred to attach a customer to the gas distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served by the utility and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators, customer service, and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as the utility's transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to the Company's requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity because they vary with the amount of gas volumes purchased by the Company for its customers.

Q. PLEASE DESCRIBE THE COST ALLOCATION PROCESS.

A. The final step is the allocation of each functionalized and classified cost element to the individual rate class. Costs typically are allocated on customer, demand, commodity, or revenue allocation factors. From a cost of service perspective, the best approach is a direct assignment of costs where costs are incurred by a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the way customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, differences in the cost of meters are reflected by using a different average meter cost for each class of service.

Q. ARE THERE FACTORS THAT CAN INFLUENCE THE OVERALL COST ALLOCATION FRAMEWORK UTILIZED BY A GAS UTILITY WHEN PERFORMING A COSS?

A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation for purposes of allocating costs to customer groups. Cost causation addresses the question – which customer or group of customers causes the utility to incur particular types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. The factors which can influence the cost allocation used to perform a COSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. WHY ARE THESE CONSIDERATIONS RELEVANT TO CONDUCTING PSNC'S COSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study was conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the state the utility operates in as it pertains to cost of service studies and gas ratemaking issues.

Q. HOW DO STATE REGULATORY POLICIES AFFECT A UTILITY'S COSS?

A. State regulatory policies and requirements prescribe whether there are any historical precedents used to establish utility rates in the state. Specifically, state regulations and past precedents set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

Q. HOW DOES THE AVAILABILITY OF DATA INFLUENCE A COSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region, and the types of load data available.

III. PSNC'S COST OF SERVICE STUDY

Q. WHAT WAS THE SOURCE OF THE COST DATA ANALYZED IN THE COMPANY'S COSS?

A. All cost of service data was extracted from the Company's total cost of service (i.e., total revenue requirement) and schedules contained in this filing. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data were derived from the historical books and records of the Company and information provided by Company personnel.

Q. WHAT ARE THE SIMILARITIES AND DIFFERENCES IN THE COST ALLOCATION APPROACH UTILIZED IN PSNC'S COSS IN THIS PROCEEDING WITH THAT UTILIZED IN PSNC'S PREVIOUS RATE CASE?

A. The general methods employed in PSNC's previous general rate case proceeding, Docket No. G-5, Sub 565 ("2016 Case"), are reflected in the COSS methods employed in the current proceeding and described in my testimony. Updated data was utilized to develop the special studies and analyses that inform the calculations and outcome of the COSS, but the general approaches used in the current proceeding are in alignment with the 2016 Case, as summarized below:

LNG Storage – LNG Storage plant and O&M costs are allocated based on the design day for each class. In the 2016 Case LNG Storage costs were allocated on the peak day forecast which appears from my review to be similar to the design day calculations used in the current proceeding's COSS.

Classification of Distribution Mains – Mains are still classified between a customer component and a demand component as described in more detail below.

Allocation of Transmission and Distribution Mains – Transmission mains and the demand component of distribution mains are allocated on the peak and average methodology, which is the same allocation basis as the 2016 Case.

Direct Assignment of Industrial Measurement and Regulation ("M&R") – Data was collected to direct assign the industrial M&R equipment to particular rate classes, replicating the same method used in the 2016 Case.

Relative Cost Studies – In the 2016 Case meters and uncollectible costs were allocated to the classes based on special costs studies of those costs and asset which allowed for a more direct assignment. The current proceeding's COSS model also relies on special cost studies for meters and uncollectible costs, but also expanded the use of special studies to the allocation of services and meter reading costs.

There is one difference in methodology that impacts the COSS results. In the 2016 Case PSNC provided a COSS for four rate classes (Residential, General Service, Large Quantity Firm Service, and Large Quantity Interruptible Service). In the current proceeding the COSS was developed with five rate classes; the General Service class was separated into two classes, Small General Service and Medium General Service.

Q. HOW ARE THE PSNC RATE CLASSES STRUCTURED FOR PURPOSES OF CONDUCTING ITS COSS?

A. For PSNC's COSS, I included five rate classes:

- Residential Service (Rate 101, Rate 102, Rate 115)
- Small General Service (Rate 125, Rate 126, Rate 127)
- Medium General Service (Rate 140)
- Large Quantity General Service (Rate 145, Rate 175)
- Large Quantity Interruptible Service (Rate 150, Rate 180)

Q. HOW ARE DISTRIBUTION MAINS CLASSIFIED IN THE COSS?

A. In alignment with past PSNC COSS studies the COSS model is classifying a portion of distribution mains as customer-related and demand-related. In the 2016 Case the method relied up on was a minimum system analyses; however, the current COSS model is relying on a zero-intercept analysis. The zero-intercept method uses linear regression analysis to compare unit costs of the various sized distribution mains installed on PSNC's gas system against the diameter of the various distribution mains installed. This method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the LDC's distribution system, regardless of its peak or annual consumption. As a result of the zero-intercept analysis the COSS classifies 60.8% of its investment in distribution mains as customer-related and 39.2% of the investment as demand-related.

Q. HOW ARE DISTRIBUTION MAINS ALLOCATED IN THE COSS?

A. In alignment with past PSNC COSS studies the customer-related portion of the distribution mains investment is allocated to the rate classes based on the number of customers on PSNC's system and the demand-related portion was allocated to the rate classes based on the Peak and Average methodology. The Peak and Average allocation was calculated using equal weight to peak demands and average demands, with the Large Quantity Interruptible Service having zero peak demands.

Q. HOW ARE OTHER CUSTOMER-RELATED PLANT COSTS ALLOCATED TO CLASSES?

A. Meters and meter installations (Account Nos. 381 and 382), are allocated based on the actual types of meters used to serve gas customers in different rate classes and the current costs of those meters and their installation. The same method is employed for FERC Account No. 385 – Industrial M&R Stations were the actual investment for Industrial Meters and Regulators by rate class is sued to allocate these costs.

Q. HOW DID THE COSS ALLOCATE DISTRIBUTION-RELATED GAS OPERATION AND MAINTENANCE ("O&M") EXPENSES?

A. In general, these expenses are allocated based on the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. Put differently, the existence of plant facilities necessitates the incurrence of cost, *i.e.*, expenses by the utility to operate and maintain those facilities. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account. For example, Account No. 887, Maintenance of Mains, is allocated on the same basis as its corresponding plant accounts, Mains – Account No. 376. With the detailed analyses supporting the assignment or allocation of major plant in service components, where feasible, it was deemed appropriate to rely upon those results in allocating related expenses in view of the overall conceptual acceptability of such an approach.

Q. PLEASE DESCRIBE THE CLASSIFICATION AND ALLOCATION OF CUSTOMER ACCOUNTS AND CUSTOMER SERVICE EXPENSES IN THE COSS.

A. Customer accounts and services expenses were classified as customer-related costs and allocated based on the average number of distribution customers by class. Exceptions to this treatment were Account Nos. 902 (Meter Reading), 903 (Customer Records & Collections) and 904 (Uncollectible Accounts). The allocation factor for meter reading expenses included additional time and effort related to meter reading for manual meter reading activities. A composite allocation factor was created for customer records and collections expenses, based on a study of the various functions and related activities of the responsibility areas that charged to this account. Uncollectible accounts expenses are assigned to the classes based on an analysis of bad debt.

Q. HOW WERE ADMINISTRATIVE AND GENERAL ("A&G") EXPENSES AND TAXES ALLOCATED TO EACH RATE CLASS?

A. A&G expenses were allocated on an account-by-account basis. Items related to labor costs, such as employee pensions and benefits, were allocated based on O&M labor costs. Items related to plant, such as maintenance of general plant and property taxes, were allocated based on plant.

Q. PLEASE DESCRIBE THE METHOD USED TO ALLOCATE THE RESERVE FOR DEPRECIATION AS WELL AS DEPRECIATION EXPENSES.

A. These items were allocated by function in proportion to their associated plant accounts.

Q. HOW DID THE COSS ALLOCATE TAXES OTHER THAN INCOME TAXES?

A. The study allocated all taxes, except for income taxes, in a manner which reflected the specific cost associated with each tax expense category. Generally, taxes can be cost classified on the basis of the tax assessment method established for each tax category and can be grouped into the following categories: (1) labor; (2) plant; and (3) revenue. In the PSNC COSS, all non-income taxes were assigned to one of the above stated categories which were then used as a basis to establish an appropriate allocation factor for each tax account.

Q. HOW WERE INCOME TAXES ALLOCATED TO EACH RATE CLASS?

A. Current income taxes were allocated based on each class' net income before taxes. Income taxes for the total revenue requirement were allocated to each class based on the allocation of rate base to each class. Income taxes at proposed revenues by class were allocated to each class based on the income prior to taxes for each class.

Q. DOES PSNC'S COSS INCLUDE GAS COMMODITY COSTS?

A. Yes. The COSS does include gas commodity costs and gas commodity revenues which are both functionalized to the gas supply function with a net income of zero; since the gas commodity costs match gas commodity revenues.

Q. HAVE YOU PROVIDED DETAILS RELATED TO THESE INPUTS AND ALLOCATIONS?

A. Yes. G-1 Item 3 – COSS, provides the printout of the full Cost of Service Study and is accompanied by an Excel based model provided as a workpaper. G-1 Item 3 – COSS provides a list of account inputs and allocation choices, resulting allocations, and details on the external allocation and classification factors utilized in the model.

Q. PLEASE SUMMARIZE THE RESULTS OF PSNC'S COSS.

A. Table 1 below presents a summary of the results of the Company's COSS that can be reviewed in detail in Schedule 1 of G-1 Item 3 – COSS. The COSS shows an overall revenue deficiency to the Company of $53.145 million.

Table 1 - Summary Results of the Company's COSS

Rate Class	Class Revenue (Deficiency)/ Excess	Rate of Return on Net Rate Base	Relative Rate of Return
Residential Service	(26,545,420)	5.90%	1.11
Small General Service	(4,753,404)	6.35%	1.19
Medium General Service	1,319,493	10.21%	1.92
Large Quantity General Service	(15,596,017)	2.04%	0.38
Large Quantity Interruptible Service	(7,570,129)	0.43%	0.08
Total Company	(53,145,478)	5.32%	1.00

Table 1 presents the revenue deficiency/excess for each rate class and the class rate of return on net rate base at present rates. Regarding rate class revenue levels, the rate of return results show that all classes except Medium General Service are being charged rates that recover less than their indicated costs of service.

Q. HAVE YOU PREPARED A MORE DETAILED SUMMARY OF PSNC'S COSS RESULTS?

A. Yes. G-1 Item 3 – COSS Schedule 1 and Schedule 2 summarizes the results of PSNC's COSS. Schedule 1 present the resulting allocation by rate class of PSNC's proposed revenue requirement based strictly on the results of the computations included in the COSS. Schedule 2 summarizes the costs allocated to PSNC's rate classes on a functionalized (*e.g.,* by production and distribution), and classified (*i.e.* by demand, customer and commodity) basis.

IV. PRINCIPLES OF SOUND RATE DESIGN

Q. PLEASE IDENTIFY THE PRINCIPLES OF RATE DESIGN UTILIZED IN DEVELOPMENT OF THE COMPANY'S RATE DESIGN PROPOSALS.

A. Several rate design principles find broad acceptance in the recognized literature on utility ratemaking and regulatory policy. These principles include:

(1) Cost of Service;

(2) Efficiency;

(3) Value of Service;

(4) Stability/Gradualism;

(5) Non-Discrimination;

(6) Administrative Simplicity; and

(7) Balanced Budget.

These rate design principles draw heavily upon the "Attributes of a Sound Rate Structure" developed by James Bonbright in Principles of Public Utility Rates.[1]

Q. CAN THE OBJECTIVES INHERENT IN THESE PRINCIPLES COMPETE WITH EACH OTHER AT TIMES?

A. Yes. These principles can compete with each other and this tension requires further judgment to strike the right balance between the principles. Detailed evaluation of rate design recommendations must recognize the potential and actual tension between these principles. Indeed, Bonbright discusses this

---

[1] Principles of Public Utility Rates, Second Edition, Page 111-113 James C. Bonbright, Albert L. Danielson, David R. Kamerschen, Public Utility Reports, Inc., 1988.

tension in detail. Rate design recommendations must deal effectively with such tension. There are tensions between cost and value of service principles as well as efficiency and simplicity. There are potential conflicts between simplicity and non-discrimination and between value of service and non-discrimination. Other potential conflicts arise where utilities face unique circumstances that must be considered as part of the rate design process.

Q. HOW ARE THESE PRINCIPLES TRANSLATED INTO THE DESIGN OF RATES?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information is evaluated before reaching a final rate design determination. Out of necessity then, the rate design process must be, in part, influenced by judgmental evaluations.

V. DETERMINATION OF PROPOSED CLASS REVENUES

Q. PLEASE DESCRIBE THE PROPOSED APPROACH TO APPORTION PSNC'S PROPOSED REVENUE INCREASE TO ITS RATE CLASSES.

A. As just described, the apportionment of revenues among rate classes consists of deriving a reasonable balance between various criteria or guidelines that relate to the design of utility rates. The various criteria that were considered in the process included: (1) cost of service; (2) class contribution to present revenue levels; and (3) customer impact considerations.

After discussions with the Company, the increase proposed in this case was allocated based on considerations of the current parity percentages shown above in Table 1 and the desire to move toward full parity over time while addressing issues of gradualism. PSNC proposes to:

- Apply the system average increase in revenue to those rate classes with parity ratios between 0.80 and 1.2 (Residential and Small General Service).
- Apply 50 percent of the average revenue increase to those rate classes above a 1.2 parity ratio (Medium General Service).
- Apply 200 percent of the average revenue increase to those rate classes with a parity ratio below 0.80 (Large Quantity General Service and Large Quantity Interruptible Service).

The result of this approach is reflected on G-1 Item 3 – COSS Schedule 3 and in Table 2 below, wherein the relative rates of return on net rate base are shown to generally converge towards unity or 1.00 compared to the same measure calculated under present rates. In addition, the amounts of the existing rate subsidies and excesses among the Company's rate classes were generally reduced. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable to move class revenues and rates closer to the indicated cost of service for each rate class.

Table 2 - Comparison of Relative Rate of Return by Rate Class

Rate Class	Current Rate of Return	Relative Rate of Return	Proposed Rate of Return	Relative Rate of Return
Residential Service	5.90%	1.11	8.10%	1.06
Small General Service	6.35%	1.19	9.10%	1.19
Medium General Service	10.21%	1.92	11.63%	1.52
Large Quantity General Service	2.04%	0.38	4.74%	0.62
Large Quantity Interruptible Service	0.43%	0.08	2.46%	0.32
Total Company	5.32%	1.00	7.64%	1.00

Q. WHAT ARE THE PERCENTAGE CHANGES IN REVENUES BY RATE CLASS RESULTING FROM THE COMPANY'S PROPOSED REVENUE APPORTIONMENT?

A. Table 3 below summarizes the proposed revenue change for each rate class and the percent change in total revenues resulting from the above-described process.

Table 3 - Proposed Class Revenue Apportionment

Rate Class	Revenues at Current Rates	Revenues at Proposed Rates	Proposed Revenue Change	Percent Change	Increase Relative to System Increase
Residential Service	359,911,473	392,834,225	32,922,753	9.15%	0.99
Small General Service	103,195,161	112,634,896	9,439,735	9.15%	0.99
Medium General Service	22,279,371	23,298,369	1,018,998	4.57%	0.49
Large Quantity General Service	41,664,590	49,287,092	7,622,502	18.29%	1.98
Large Quantity Interruptible Service	11,705,385	13,846,875	2,141,488	18.29%	1.98
Other Revenue	35,356,845	35,356,845	0	0.00%	-
Total Company	574,112,825	627,258,303	53,145,476	9.26%	1.00

Further, the Company's percentage changes of distribution margin revenues associated with its proposed revenue apportionment by rate class are summarized in Table 4 below. As can be seen in this table, the proposed increase to the Residential class is 0.87 times the overall system increase of 16.60%.

Table 4 - Proposed Change in Distribution Margin Revenues by Rate

Rate Class	Distribution Margin Revenues at Current Rates	Distribution Margin Revenues at Proposed Rates	Proposed Revenue Change	Percent Change	Increase Relative to System Increase	Percent of Total Distribution Margin Revenues
Residential Service	228,291,109	261,213,862	32,922,753	14.42%	0.87	69.99%
Small General Service	50,545,224	59,984,959	9,439,735	18.68%	1.12	16.07%
Medium General Service	10,298,482	11,317,481	1,018,998	9.89%	0.60	3.03%
Large Quantity General Service	23,576,832	31,199,334	7,622,502	32.33%	1.95	8.36%
Large Quantity Interruptible Service	7,362,216	9,503,704	2,141,488	29.09%	1.75	2.55%
Total Company	320,073,864	373,219,340	53,145,476	16.60%		100.00%

VI. PSNC'S RATE DESIGN

Q. PLEASE SUMMARIZE THE PROPOSED RATE DESIGN.

A. PSNC is proposing no increases to the basic facilities charge or other miscellaneous fees. The proposed revenue increases will be fully recovered through the volumetric charges. No changes were made to the block rate structures nor the winter summer distinction for the Residential classes. The proposed volumetric rate differentials (i.e., winter & summer differentials and block rate differentials) were kept consistent between present and proposed rates. For example, the rate differential between summer and winter for Rate 101 was $0.066 and the differential for the proposed rates remains $0.066.

Q. HAVE YOU PROVIDED A SCHEDULE DETAILING THE PROPOSED RATES AND CORRESPONDING REVENUES?

A. Yes. G-1 Item 3 – COSS Schedule 7 shows the derivation of each rate component for each of PSNC's tariff schedules and the corresponding revenues generated from those proposed rates.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

Appendix A - Resume or John D. Taylor

ATRIUM ECONOMICS

John D. Taylor

Managing Partner, Atrium Economics LLC

Mr. Taylor is a utility pricing expert with experience developing cost of service studies for both electric and gas utilities and transmission companies. He has deep experience with developing residential and commercial rates, analyzing midstream transportation and storage capacity resources, and assessing the relationship between price signals and the adoption of distributed generation assets. He has filed testimony as an expert witness on class cost of service studies for both electric and natural gas utilities, return on equity, and on the appropriate use of statistical analysis during audit testing. Mr. Taylor has supported projects involving financial analysis, regulatory support and strategy, market assessment, litigation support, and organizational and operations reviews. He has an expert knowledge of cost allocation principles for utility cost of service studies and for affiliate transaction and service agreements. Mr. Taylor's work often involves providing support for regulatory proceedings by conducting various studies and analyses related to revenue requirements, affiliate transactions, class cost of service, and cash working capital studies. He has also been involved in the sale of generating assets as sell side advisors, supporting due diligence efforts, financial analyses, and regulatory approval processes.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

15

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

EXPERT WITNESS TESTIMONY PRESENTATION

<u>United States</u>

- Delaware Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- Oregon Public Utility Commission
- Pennsylvania Public Utility Commission
- Washington Utilities and Transportation Commission

<u>Canada</u>

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

REPRESENTATIVE EXPERIENCE

Rate Design and Regulatory Proceedings

Mr. Taylor has worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.
- Developed revenue requirement model to comply with a new performance based formula ratemaking process for a Midwest electric utility.
- Supported the developed of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission’s audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

Litigation Support and Expert Testimony

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.

- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

Transaction Experience

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

Financial Analysis and Market Research

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost of service model for a New England gas distribution company.
- Developed distributed CNG/LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632

DIRECT TESTIMONY

OF

JOHN J. SPANOS

APRIL 1, 2021

I. INTRODUCTION

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

A. My name is John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011. I am President of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING?

A. I have been associated with the firm since my college graduation in June 1986.

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

A. I am testifying on behalf of Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or the "Company").

Q. PLEASE STATE YOUR QUALIFICATIONS.

A. I have 34 years of depreciation experience, which includes expert testimony in over 350 cases before 41 regulatory commissions. These cases have included depreciation studies in the electric, gas, water, wastewater and pipeline industries. In addition to cases where I have submitted testimony, I have also supervised over 700 other depreciation or valuation assignments. Please refer to Spanos Direct Exhibit 1 for my qualifications statement, which includes further information with respect to my work history, case experience, and leadership in the Society of Depreciation Professionals.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony will support and explain the Depreciation Study performed for PSNC attached hereto as Spanos Direct Exhibit 2 ("Depreciation Study"). The Depreciation Study sets forth the calculated annual depreciation accrual rates by account as of December 31, 2020.

Q. HAVE YOU PREPARED EXHIBITS IN SUPPORT OF YOUR TESTIMONY?

A. Yes. The following exhibits were prepared by me or under my direction and supervision:

Spanos Direct Exhibit 1 – Qualification Statement

Spanos Direct Exhibit 2 – Depreciation Study

Spanos Direct Exhibit 3 – Comparison of Current Annual Depreciation Expense vs. Proposed Annual Depreciation Expense

Q. PLEASE SUMMARIZE THE RESULTS OF YOUR DEPRECIATION STUDY.

A. The depreciation rates as of December 31, 2020, appropriately reflect the rates at which the value of PSNC's assets have been consumed over their useful lives to date. These rates are based on the most commonly used methods and procedures for determining depreciation rates. The life and salvage parameters are based on widely used techniques and the depreciation rates are based on the average service life procedure and remaining life method.

Q. ARE THE RECOMMENDED DEPRECIATION ACCRUAL RATES PRESENTED IN YOUR STUDY REASONABLE AND APPLICABLE TO THE PLANT IN SERVICE AS OF DECEMBER 31, 2020?

A. Yes, they are. Based on the Depreciation Study, I am recommending depreciation rates using the December 31, 2020, plant and reserve balances for approval.

Q. WHAT IS THE EFFECT OF THE RECOMMENDED DEPRECIATION ACCRUAL RATES ON THE COMPANY'S COST OF SERVICE?

A. As explained in more detail later in my testimony, the Depreciation Study results in a decrease of $3.8 million in depreciation expense. This decrease is primarily the result of changes in the life parameters and net salvage accruals for some accounts and an emphasis on proper recovery methodologies of general plant assets.

III. DEPRECIATION STUDY

Q. PLEASE DEFINE THE CONCEPT OF DEPRECIATION.

A. Depreciation refers to the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of utility plant in the course of service from causes which are known to be in current operation, against which the Company is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand, and the requirements of public authorities.

Q. DID YOU PREPARE THE DEPRECIATION STUDY FILED BY PSNC IN THIS PROCEEDING?

A. Yes. I prepared the Depreciation Study, and Spanos Direct Exhibit 2 is a true and accurate copy of my report. My report is entitled: "2020 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2020." This report sets forth the results of my Depreciation Study for PSNC.

Q. IN PREPARING THE DEPRECIATION STUDY, DID YOU FOLLOW GENERALLY ACCEPTED PRACTICES IN THE FIELD OF DEPRECIATION VALUATION?

A. Yes.

Q. WHAT IS THE PURPOSE OF THE DEPRECIATION STUDY?

A. The purpose of my Deprecation Study was to estimate the annual depreciation accruals for PSNC's plant in service for financial and ratemaking purposes and to determine appropriate average service lives and net salvage percentages for each plant account.

Q. ARE THE METHODS AND PROCEDURES OF THIS DEPRECIATION STUDY CONSISTENT WITH PSNC'S PAST PRACTICES?

A. The methods and procedures of this study are the same as those utilized in the past by this Company as well as other companies appearing before this Commission. Both the existing rates and the rates determined in the Depreciation Study are based on the average service life procedure and the remaining life method.

Q. PLEASE DESCRIBE THE CONTENTS OF THE DEPRECIATION STUDY.

A. The Depreciation Study is presented in nine parts: Part I, Introduction, presents the scope and basis for the Depreciation Study. Part II, Estimation of Survivor Curves, includes descriptions of the methodology of estimating survivor curves. Parts III and IV set forth the analysis for determining service life and net salvage estimates. Part V, Calculation of Annual and Accrued Depreciation, includes the concepts of depreciation and amortization using the remaining life. Part VI, Results of Study, presents a description of the results of my analysis and a summary of the depreciation calculations. Parts VII, VIII, and IX include graphs and tables that relate to the service life and net salvage analyses, and the detailed depreciation calculations by account.

Table 1 on pages VI-4 through VI-6 of the Depreciation Study presents the estimated survivor curve, the net salvage percent, the original cost as of December 31, 2020, the book depreciation reserve, and the calculated annual depreciation accrual and rate for each account or subaccount. The section beginning on page VII-2 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VIII-2 presents the results of the salvage analysis. The section beginning on page IX-2 presents the depreciation calculations related to surviving original cost as of December 31, 2020.

Q. PLEASE EXPLAIN HOW YOU PERFORMED YOUR DEPRECIATION STUDY.

A. I used the straight line remaining life method of depreciation, with the average service life procedure. The annual depreciation is based on a method of depreciation accounting that seeks to distribute the unrecovered cost of fixed capital assets over the estimated remaining useful life of each unit, or group of assets, in a systematic and rational manner.

For General Plant Accounts 491.1, 491.5, 491.6, 493.0, 494.6, 497.0, 497.1, 498.0, and 498.1, I used the straight line remaining life method of amortization.[1] The annual amortization is based on amortization accounting that distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account and vintage.

Q. HOW DID YOU DETERMINE THE RECOMMENDED ANNUAL DEPRECIATION ACCRUAL RATES?

A. I did this in two phases. In the first phase, I estimated the service life and net salvage characteristics for each depreciable group, that is, each plant account or subaccount identified as having similar characteristics. In the second phase, I calculated the composite remaining lives and annual depreciation accrual rates based on the service life and net salvage estimates determined in the first phase.

[1] The account numbers identified throughout my testimony represent those in effect as of December 31, 2020.

Q. PLEASE DESCRIBE THE FIRST PHASE OF THE DEPRECIATION STUDY, IN WHICH YOU ESTIMATED THE SERVICE LIFE AND NET SALVAGE CHARACTERISTICS FOR EACH DEPRECIABLE GROUP.

A. The service life and net salvage study consisted of compiling historical data from records related to PSNC's plant; analyzing these data to obtain historical trends of survivor characteristics; obtaining supplementary information from PSNC's management and operating personnel concerning practices and plans as they relate to plant operations; and interpreting the data and the estimates used by other gas utilities to form judgments of average service life and net salvage characteristics.

Q. WHAT HISTORICAL DATA DID YOU ANALYZE FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. I analyzed the Company's accounting entries that record plant transactions during the period 1940 through 2020 to the extent available. The transactions I analyzed included additions, retirements, transfers, sales, and the related balances.

Q. WHAT METHOD DID YOU USE TO ANALYZE THE SERVICE LIFE DATA?

A. I used the retirement rate method for most plant accounts. This is the most appropriate method when retirement data covering a long period of time is available, because this method determines the average rates of retirement actually experienced by the Company during the period of time covered by the Depreciation Study.

Q. PLEASE DESCRIBE HOW YOU USED THE RETIREMENT RATE METHOD TO ANALYZE PSNC'S SERVICE LIFE DATA.

A. I applied the retirement rate analysis to each different group of property in the study. For each property group, I used the retirement rate data to form a life table which, when plotted, shows an original survivor curve for that property group. Each original survivor curve represents the average survivor pattern experienced by the several vintage groups during the experience band studied. The survivor patterns do not necessarily describe the life characteristics of the property group; therefore, interpretation of the original survivor curves is required in order to use them as valid considerations in estimating service life. The "Iowa-type survivor curves," or "Iowa curves," were used to perform these interpretations.

Q. WHAT ARE "IOWA-TYPE SURVIVOR CURVES" AND HOW DID YOU USE SUCH CURVES TO ESTIMATE THE SERVICE LIFE CHARACTERISTICS FOR EACH PROPERTY GROUP?

A. Iowa-type survivor curves are a widely-used group of survivor curves that contain the range of survivor characteristics usually experienced by utilities and other industrial companies. These curves were developed at the Iowa State College Engineering Experiment Station through an extensive process of observing and classifying the ages at which various types of property used by utilities and other industrial companies had been retired.

Iowa-type survivor curves are used to smooth and extrapolate original survivor curves determined by the retirement rate method. The Iowa curves and truncated Iowa curves were used in the PSNC Depreciation Study to describe the forecasted rates of retirement based on the observed rates of retirement and the outlook for future retirements. The estimated survivor curve designations for each depreciable property group indicate the average service life, the family within the Iowa system to which the property group belongs, and the relative height of the mode. For example, the Iowa 50-R2.5 indicates an average service life of 50 years; a right-moded, or R, type curve (the mode occurs after average life for right-moded curves); and a moderate height, 2.5, for the mode (possible modes for R type curves range from 0.5 to 5).

Q. WHAT APPROACH DID YOU USE TO ESTIMATE THE LIVES OF SIGNIFICANT STORAGE FACILITIES AND SERVICE CENTERS?

A. I used the life span technique to estimate the lives of significant facilities for which concurrent retirement of the entire facility is anticipated. In this technique, the survivor characteristics of such facilities are described by the use of interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the facility, such as, for a storage facility, the retirement of assets such as pumps, motors and piping that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the facility by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation for a particular facility inasmuch as a single concurrent retirement for all years of installation will occur when it is retired.

Q. IS THIS APPROACH WIDELY ACCEPTED FOR ESTIMATING THE SERVICE LIVES FOR THESE FACILITIES?

A. Yes. The life span has been used previously for PSNC. My firm has also used the life span technique in performing depreciation studies presented to many other public utility commissions across the United States and Canada.

Q. HOW ARE THE LIFE SPANS ESTIMATED FOR PSNC'S MAJOR FACILITIES?

A. The life span estimates are based on informed judgment that incorporates factors for each facility such as the technology of the facility, management plans and outlook for the facility, and the estimates for similar facilities for other utilities.

Q. DID YOU PHYSICALLY OBSERVE PSNC'S PLANT AND EQUIPMENT AS PART OF YOUR DEPRECIATION STUDY?

A. Yes. I made a field review of PSNC's property as part of this study during February 2021 to observe representative portions of plant. Also, I have conducted field visits in prior studies in 2015, 2010, and 2005. Field reviews are conducted to become familiar with Company operations and obtain an understanding of the function of the plant and information with respect to the reasons for past retirements and the expected future causes of retirements. This knowledge was incorporated in the interpretation and extrapolation of the statistical analyses.

Q. HOW DID YOUR EXPERIENCE IN DEVELOPMENT OF OTHER DEPRECIATION STUDIES AFFECT YOUR WORK IN THIS CASE FOR PSNC?

A. Because I customarily conduct field reviews for my depreciation studies, I have had the opportunity to visit scores of similar facilities and meet with operations personnel at many other companies. The knowledge I have accumulated from those visits and meetings provides me with useful information to draw upon to confirm or challenge my numerical analyses concerning asset condition and remaining life estimates.

Q. PLEASE EXPLAIN THE CONCEPT OF "NET SALVAGE".

A. Net salvage is a component of the service value of capital assets that is recovered through depreciation rates. The service value of an asset is its original cost less its net salvage. Net salvage is the salvage value received for the asset upon retirement less the cost to retire the asset. When the cost to retire the asset exceeds the salvage value, the result is negative net salvage.

Because depreciation expense is the loss in service value of an asset during a defined period (*e.g.*, one year), it must include a ratable portion of both the original cost of the asset and the net salvage. That is, the net salvage related to an asset should be incorporated in the cost of service during the same period as its original cost, so that customers receiving service from the asset pay rates that include a portion of both elements of the asset's service value, the original cost, and the net salvage value.

For example, the full recovery of the service value of a $500 regulator will include not only the $500 of original cost, but also, on average $150 to remove the regulator at the end of its life and $25 in salvage value. In this example, the net salvage component is negative $125 ($25 - $150), and the net salvage percent is negative 25% (($25 - $150)/$500).

Q. PLEASE DESCRIBE HOW YOU ESTIMATED NET SALVAGE PERCENTAGES.

A. The net salvage percentages estimated in the Depreciation Study were based on informed judgment that incorporated factors such as the statistical analyses of historical net salvage data; information provided to me by the Company's operating personnel, general knowledge and experience of industry practices; and trends in the industry in general. The statistical net salvage analyses incorporated the Company's actual historical data for the period 1987 through 2020, and considered the cost of removal and gross salvage ratios of the associated retirements during the 34-year period. Trends of these data are also measured based on three-year moving averages and the most recent five-year indications.

Q. PLEASE DESCRIBE THE SECOND PHASE OF THE PROCESS THAT YOU USED IN THE DEPRECIATION STUDY IN WHICH YOU CALCULATED COMPOSITE REMAINING LIVES AND ANNUAL DEPRECIATION ACCRUAL RATES.

A. After I estimated the service life and net salvage characteristics for each depreciable property group, I calculated the annual depreciation accrual rates for each group using the straight line remaining life method, and using remaining lives weighted consistent with the average service life procedure. The calculation of annual depreciation accrual rates were developed as of December 31, 2020.

Q. PLEASE DESCRIBE THE STRAIGHT LINE REMAINING LIFE METHOD OF DEPRECIATION.

A. The straight line remaining life method of depreciation allocates the original cost of the property, less accumulated depreciation, less future net salvage, in equal amounts to each year of remaining service life.

Q. PLEASE DESCRIBE THE AVERAGE SERVICE LIFE PROCEDURE FOR CALCULATING REMAINING LIFE ACCRUAL RATES.

A. The average service life procedure defines the group or account for which the remaining life annual accrual is determined. Under this procedure, the annual accrual rate is determined for the entire group or account based on its average remaining life and the rate is then applied to the surviving balance of the group's cost. The average remaining life of the group is calculated by first dividing the future book accruals (original cost less allocated book reserve less future net salvage) by the average remaining life for each vintage. The average remaining life for each vintage is derived from the area under the survivor curve between the attained age of the vintage and the maximum age. The sum of the future book accruals is then divided by the sum of the annual accruals to determine the average remaining life of the entire group for use in calculating the annual depreciation accrual rate.

Q. PLEASE DESCRIBE AMORTIZATION ACCOUNTING IN CONTRAST TO DEPRECIATION ACCOUNTING.

A. Amortization accounting is used for accounts with a large number of units, but small asset values. In amortization accounting, units of property are capitalized in the same manner as they are in depreciation accounting. However, depreciation accounting is difficult for these types of assets because depreciation accounting requires periodic inventories to properly reflect plant in service. Consequently, amortization accounting is used for these types of assets, such that retirements are recorded when a vintage is fully amortized rather than as the units are removed from service. That is, there is no dispersion of retirement in amortization accounting. All units are retired when the age of the vintage reaches the amortization period. Each plant account or group of assets is assigned a fixed period that represents an anticipated life during which the asset will render full benefit. For example, in amortization accounting, assets that have a 20-year amortization period will be fully recovered after 20 years of service and taken off the Company's books at that time, but not necessarily removed from service. In contrast, assets that are taken out of service before 20 years remain on the books until the amortization period for that vintage has expired.

Q. IS AMORTIZATION ACCOUNTING BEING UTILIZED FOR CERTAIN PLANT ACCOUNTS?

A. Yes. However, amortization accounting is only appropriate for certain General Plant accounts. These accounts are 491.1, 491.5, 491.6, 493.0, 494.6, 497.0, 497.1, 498.0, and 498.1, which represent less than one percent of PSNC's depreciable plant.

Q. HAVE YOU MADE ADDITIONAL RECOMMENDATIONS FOR THESE AMORTIZATION ACCOUNTS?

A. Yes. In order to achieve a more stable accrual rate for these accounts in the future, I have recommended a five-year amortization to adjust the unrecovered reserve. This approach will achieve consistent amortization rates for existing assets as well as future assets.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE HOW THE ANNUAL DEPRECIATION ACCRUAL RATE FOR A PARTICULAR GROUP OF PROPERTY IS PRESENTED IN YOUR DEPRECIATION STUDY.

A. I will use Account 476.3, Mains – Steel, as an example because it is one of the larger depreciable accounts and represents approximately 18 percent of depreciable plant. The retirement rate method was used to analyze the survivor characteristics of this property group. Aged plant accounting data was compiled from 1940 through 2020 and analyzed in periods that best represent the overall service life of this property. The life tables for the 1940-2020 and 1996-2020 experience bands are presented on pages VII-60 through VII-65 of the Depreciation Study. The life tables display the retirement and surviving ratios of the aged plant data exposed to retirement by age interval. For example, page VII-60 of the study shows $262,939 retired at age 0.5 with $435,403,204 exposed to retirement. Consequently, the retirement ratio is 0.0006 and the surviving ratio is 0.9994. These life tables, or original survivor curves, are plotted along with the estimated smooth survivor curve, the 68-R2.5 on page VII-59 of the study.

The combined net salvage analyses for Accounts 476.1 and 476.3, Mains, are presented on pages VIII-20 and VIII-21 of the Depreciation Study. The percentage is based on the result of annual gross salvage minus the cost to remove plant assets as compared to the original cost of plant retired during the period 1987-2020. This 34-year period experienced $12,021,743 ($109,487 - $12,131,230) in negative net salvage for $30,480,051 plant retired. The result is negative net salvage of 39 percent ($12,021,743/$30,480,051). Based on the overall negative 39 percent net salvage and the most recent five years of negative 34 percent, as well as industry ranges and Company expectations, it was determined that negative 40 percent is the most appropriate estimate.

My calculation of the annual depreciation related to the original cost at December 31, 2020, of gas plant is presented on pages IX-42 through IX-44 of the study. The calculation is based on the 68-R2.5 survivor curve, 40 percent negative net salvage, the attained age, and the allocated book reserve. The tabulation sets forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. These totals are brought forward to the table on page VI-5 of the Depreciation Study.

Q. PLEASE COMPARE THE PROPOSED DEPRECIATION EXPENSE TO THE CURRENT PRO FORMA DEPRECIATION EXPENSE AS OF DECEMBER 31, 2020.

A. Spanos Direct Exhibit 3 sets forth the proposed versus current depreciation expense as of December 31, 2020. The overall change reflected in the Depreciation Study is a decrease of approximately $3.8 million annually.

Q. WHAT ARE THE PRIMARY FACTORS CAUSING THE CHANGE IN DEPRECIATION EXPENSE AS A RESULT OF THE DEPRECIATION STUDY?

A. Depreciation rates and expense are generally affected by four major factors: 1) The life and salvage parameters; 2) the plant activity; 3) the depreciation methods and procedures; and 4) the plant to reserve ratio. As shown in Spanos Direct Exhibit 3 the largest change in depreciation expense relates to Accounts 467, 468, 480.1, 480.2, 481.1, 491.5, 491.6, and 492.4. The increase in depreciation expense for Account 467, Mains is primarily due to the slightly shorter estimated average service life. The decreased depreciation expense for Account 468, Compressor Equipment is due to the longer estimated average service life for the large compressors. The increase in depreciation expense for Account 480.1, Services – Plastic is due to the more negative net salvage percent. The increase in depreciation expense for Account 480.2, Services – Steel is due to the more negative net salvage percent and a slightly shorter average service life. The decrease in depreciation expense for Account 481.1, Meters- ERT is due to the slightly longer average service life. The decrease in depreciation expense for Accounts 491.5, Computer Equipment and 491.6, Remote Meter Reading Equipment is primarily due to the low plant growth, high reserve to plant ratio and full implementation of amortization accounting. The decrease in depreciation expense for Account 492.4, Transportation Equipment – Trucks is due to the higher net salvage percentage and the high reserve to plant ratio developed for some of the trucks that have lasted longer than usual.

Q. HAVE YOU ESTABLISHED DEPRECIATION RATES FOR FUTURE ASSETS?

A. Yes. For new assets that may be placed into plant in service after January 1, 2020, for Account 492.1, Transportation Equipment – Automobiles, I have recommended a depreciation rate of 16.63 percent. This rate is based on a 5-R3 survivor curve and positive 25 percent net salvage.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632

DIRECT TESTIMONY

OF

JAMES HERNDON

April 1, 2021

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

A. My name is James Herndon, and I am a Vice President in the Strategy and Planning Practice within the Utility Services business unit of Nexant, Inc. ("Nexant"). My business address is 2000 Regency Parkway, Suite 455, Cary, North Carolina 27518. A statement of my background and qualifications is attached as Appendix A.

Q. PLEASE DISCUSS YOUR AREAS OF RESPONSIBILITY.

A. I am responsible for providing consulting services to Nexant clients in the field of energy efficiency ("EE") and conservation. In this capacity, I primarily focus on EE planning and evaluation for electric and gas utilities, including analysis of market impacts, assisting utilities in the identification of EE opportunities, and the development and design of EE initiatives. This includes the development of market baseline and potential studies, cost-benefit analyses, and design of comprehensive EE programs and portfolios.

Q. PLEASE DESCRIBE NEXANT, INCLUDING ITS HISTORY, ORGANIZATION, AND SERVICES PROVIDED.

A. Nexant, founded in 2000, is a globally recognized software, consulting, and services firm that provides innovative solutions to utilities, energy enterprises, chemical companies, and government entities worldwide. Nexant's Utility Services business unit provides demand-side management ("DSM") engineering and consulting services to government agencies and utilities, and helps commercial, institutional, and industrial facility owners to manage energy consumption and reduce costs in their facilities. Nexant conducts development and implementation services of DSM programs for public and investor-owned utilities, governments, and end-use customers. Our range of experience in the DSM field includes but is not limited to:

- Market potential assessments;
- Program design;
- Program implementation;
- Marketing;
- Vendor outreach, education, and training;
- Incentive processing and fulfillment;
- Turnkey customer service;
- Online program tracking and reporting; and
- Evaluation, measurement and verification.

Q. PLEASE INDICATE COMPANIES AND ROLES IN WHICH NEXANT HAS SUPPORTED DSM INITIATIVES.

A. Nexant has developed and administered DSM programs for clients across the country. An abbreviated, but representative, listing of our key clients is included in Appendix B of my testimony.

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

A. The purpose of my testimony is to provide information regarding Public Service Company of North Carolina, Inc.'s ("PSNC" or the "Company") proposed amended and expanded conservation programs filed for approval in Docket No.

G-5, Sub 634, the cost for which the Company seeks recovery through deferred accounting treatment and a rider. Additionally, I will provide support for the Company's proposed voluntary renewable energy program for PSNC customers, which will be known as the GreenTherm™ Renewable Natural Gas Program ("GreenTherm™ Program").

Specifically, the purpose of my testimony is to summarize the conservation program design process conducted by Nexant and PSNC, and to provide an overview of the proposed programs, including program details related to estimated participation, costs, natural gas savings, and cost-effectiveness. Additionally, I provide a review of renewable energy programs for other utilities across the country as a comparison point for the proposed GreenTherm™ Program.

Q. HAVE YOU PROVIDED TESTIMONY IN OTHER REGULATORY PROCEEDINGS?

A. Yes. I have submitted testimony before the Virginia State Corporation Commission, the Florida Public Service Commission, and the New Jersey Board of Public Utilities.

Q. ARE YOU SPONSORING ANY EXHIBITS IN CONNECTION WITH YOUR DIRECT TESTIMONY?

A. Yes. I am presenting three exhibits, which have been prepared under my direction and supervision and are accurate and complete to the best of my knowledge and belief. The schedules attached hereto are described below.

- Herndon Direct Exhibit 1 – Summary of Proposed Program Updates

- Herndon Direct Exhibit 2 – Program Plans
- Herndon Direct Exhibit 3 – Summary of Program and Portfolio Impacts, including estimated annual energy savings, annual budgets, and cost-effectiveness results

I. CONSERVATION PROGRAMS

Q. PLEASE EXPLAIN YOUR INVOLVEMENT IN THE DEVELOPMENT OF PSNC'S PROPOSED CONSERVATION PROGRAMS.

A. I served as the project manager for the program development. My responsibilities included management of the programs' scope and schedule, day-to-day coordination of communications between PSNC and Nexant, and technical oversight and quality assurance for Nexant's calculations and program analysis.

Q. PLEASE DESCRIBE NEXANT'S APPROACH IN DEVELOPING PSNC'S PROPOSED CONSERVATION PROGRAMS.

A. Nexant's goal was to assist PSNC to update its portfolio of conservation programs in order to help PSNC's customers conserve energy and improve the efficiency of their homes and commercial businesses.

First, Nexant reviewed data on PSNC's current programs, which PSNC has offered since 2009. PSNC provided Nexant with detailed program data, the Conservation Program Annual Reports filed with the Commission, and other supporting materials. Nexant conducted interviews with PSNC staff to analyze the current program offerings. Nexant also collected general information about

PSNC's customer base to help PSNC determine the measures that would have the greatest impact on eligible customers.

Next, Nexant developed a preliminary list of conservation measures that might be applicable to PSNC customers' homes and businesses based on current PSNC programs as well as Nexant's experience designing, implementing, and evaluating conservation programs around the country. Nexant reviewed the preliminary list with PSNC to refine and develop the list into program offerings. Nexant then developed measure impact estimates, including incremental costs, natural gas savings, and estimated useful life in order to evaluate the cost-effectiveness, potential participation levels, and overall benefits to PSNC's customers. Based on the quantitative assessment of measure and program costs and benefits, the measure list and proposed program offerings were further refined into final proposed program offerings.

Q. PLEASE PROVIDE A SUMMARY OF THE PROPOSED PSNC PROGRAMS.

A. PSNC proposes three new programs and expansions of two existing programs that provide opportunities for PSNC customers to improve the efficiency of their homes and businesses. In addition, PSNC will continue to offer the Conservation Education Program without modification. A description of each program is included in the Program Plans provided in Herndon Direct Exhibit 2.

Q. PLEASE DESCRIBE THE THREE NEW CONSERVATION PROGRAMS THAT THE COMPANY IS PROPOSING.

A. PSNC proposes to offer the following three new programs:

Residential New Construction Program. This program focuses on improving the efficiency of new homes built in PSNC's service territory by encouraging builders to incorporate efficient technologies and building practices in the construction of their homes. The program provides financial incentives to participating builders who construct homes that include eligible measures. The program includes two participation paths: 1) a whole home path that requires homes to meet or exceed the North Carolina Energy Conservation Code – High Efficiency Residential Option ("HERO") standards[1]; or 2) an individual equipment path with incentives offered based on the installation of qualifying natural gas equipment in the home. The program also will align with proposed amendments to the High Efficiency Discount Rate program, through which PSNC will allow homes that qualify through the whole-home path to be eligible for the High Efficiency Discount Rate.

Home Energy Report Program. Under this program, participants receive customized reports on how their energy usage compares with other homes in the area. The reports will also provide tips on how to best manage energy use, save on monthly gas bills, and participate in other PSNC programs. Based on the results from similar programs around the country, including by Duke Energy in North Carolina, these reports will encourage behavioral changes in energy usage by customers receiving the reports.

---

[1] 2018 North Carolina State Building Code: Energy Conservation Code, Appendix R4 Additional Voluntary Criteria for Increasing Energy Efficiency (High-Efficiency Residential Option (May 2018), *available at* https://codes.iccsafe.org/content/NCECC2018/appendix-r4-additional-voluntary-criteria-for-increasing-energy-efficiency-high-efficiency-residential-option-.

Residential Low Income Program. This program improves the performance of homes occupied by low-income customers. The program will offer in-home site visits that include an assessment of energy efficiency improvements, and then the direct installation of natural gas saving measures, including both low-cost, easily installed measures such as high efficiency showerheads, faucet aerators, and hot water pipe insulation, as well as higher-cost, labor-intensive measures such as air sealing, duct sealing, and additional insulation.

Q. PLEASE DESCRIBE THE EXISTING PROGRAMS THE COMPANY PROPOSES TO EXPAND.

A. PSNC proposes to expand the following two programs:

Energy Efficiency Rebate Program. This program offers rebates to residential and commercial customers to encourage the replacement of existing natural gas equipment with energy efficient equipment. The program provides financial incentives to participating customers who purchase and install qualifying high efficiency natural gas equipment in their homes and businesses. To provide additional opportunities for PSNC customers, the existing space heating and water heating rebates will be updated to include currently applicable efficiency standards and additional categories of eligible equipment, and the program will expand to offer rebates for smart thermostats and high efficiency natural gas commercial food service equipment.

High Efficiency Discount Rate Program. This program encourages the construction of homes and commercial buildings that are substantially more energy efficient than those built to code standards. The program allows residential customers with eligible homes to qualify for service under Rate Schedule 102 that includes a discounted rate per therm. The proposed program will be expanded to include both ENERGY STAR certified homes (which are currently eligible) as well as homes that meet the North Carolina HERO Code, described above in the New Construction program summary. The expanded eligibility incorporates this North Carolina-specific efficiency code option and aligns with the proposed New Construction Program to further encourage the construction of energy efficient homes. The program will also continue to allow commercial customers with new buildings that are Leadership in Energy and Environmental Design ("LEED") certified to qualify for service under Rate Schedule 127, which provides a discounted rate.

Q. PLEASE DESCRIBE THE CONSERVATION EDUCATION PROGRAM.

A. This program provides educational performances to schools on the importance of natural gas conservation and safety. A third-party provider, The National Theatre for Children, delivers the program to elementary schools in PSNC's service territory.

Q. PLEASE DESCRIBE HOW INDIVIDUAL ENERGY EFFICIENCY MEASURE IMPACTS WERE DETERMINED.

A. Nexant evaluated the energy savings, measure lives, and incremental customer costs (collectively referred to as measure impacts) of the measures described above. Nexant relied on a combination of primary and secondary sources as follows:

- Natural gas savings were determined using engineering calculations that incorporated local weather characteristics, as appropriate, as well as verified impacts from similar programs in other jurisdictions, weather adjusted as appropriate, and publicly available energy efficiency technical reference manuals.
- Equipment useful lives were derived from a review of industry standard secondary sources.
- Incremental customer costs were based on a combination of locally applicable sources, including local retail cost data and average cost data provided by industry accepted sources, such as publicly available technical reference manuals. In line with industry standards, the incremental cost of a specific measure is defined as the cost to upgrade to the high efficiency technology from the baseline technology. For measures that are typically replaced at the end of their useful life, such as furnaces, the incremental cost reflects the cost to upgrade from a standard efficiency system.

Q. HOW WAS THE COST-EFFECTIVENESS OF THE PROPOSED PROGRAMS EVALUATED?

A. The newly proposed and expanded programs were evaluated from the perspectives of four standard cost-benefit analysis tests, which are consistent with the California Standard Practice Manual. These tests can be described as follows:

- Utility Cost Test ("UCT") – this test is designed to measure the cost-effectiveness of a program from the utility's perspective.
- Total Resource Cost Test ("TRC") – this test is designed to measure whether a program is cost-effective from a societal perspective and includes both the participant's costs and the utility's costs.
- Participant Cost Test ("PCT") – this test is designed to measure the cost-effectiveness of the program from the perspective of the customer who installs the eligible program measure.
- Ratepayer Impact Measure Test ("RIM") – this test is designed to measure the impact on customer bills or rates due to changes in utility revenues and operating costs resulting from the program.

The results of each test are typically presented as a ratio of benefits to costs. In general, if benefits are equal to or greater than costs, resulting in a ratio of 1.0 or greater, the measure or program passes from that test perspective.

Q. PLEASE DESCRIBE THE COST-BENEFIT ANALYSIS PROCESS AND RESULTS FOR THE PROPOSED CONSERVATION PROGRAMS.

A. The cost-benefit analysis for the newly proposed and expanded programs included three key components as follows:

1. Measure-Level Analysis: For each energy efficiency measure, Nexant evaluated the associated measure costs and benefits. Measure-level costs included customer costs and incentives, as applicable. Program and portfolio administrative costs were excluded from the measure-level analysis.

2. Program-Level Analysis: Upon completion of the measure-level analysis, Nexant analyzed the program costs and benefits of the proposed offerings. During this step, program-specific operational and administrative program costs were included and summed along with the measure-level costs within a program to assess the program impacts. Overall costs for managing, administering, and evaluating the portfolio of proposed programs were also allocated to individual programs in order to include all costs in the program-level analysis.
3. Portfolio-Level Analysis: Program impacts for each of the newly proposed and expanded programs were summed. For purposes of this portfolio analysis, Nexant also included the Conservation Education Program.

Q. CAN YOU SUMMARIZE THE FINDINGS OF THE COST-BENEFIT ANALYSIS?

A. Herndon Direct Exhibit 3 provides the cost-benefit analysis results for each program and the overall portfolio in the proposed conservation programs. With the exception of the Conservation Education Program and Low Income Program, each program and the overall portfolio have benefit/cost ratios greater than 1.0 from the UCT perspectives, with a portfolio benefit/cost ratio of 1.3 for the UCT. Consistent with PSNC's application for the current conservation programs, included in Docket No. G-5, Sub 495A, and in subsequent PSNC Conservation Program Annual Reports, the UCT perspective was utilized as the primary test perspective in assessing program and portfolio cost-effectiveness.

Q. WHAT ARE THE ESTIMATED IMPACTS ATTRIBUTABLE TO THE PORTFOLIO OF PROGRAMS?

A. The proposed programs will result in annual energy savings ranging from approximately 1,900,000 therms to approximately 2,600,000 therms over five program years as shown in Herndon Direct Exhibit 2, and a cumulative lifetime energy savings of over 60,000,000 therms, the net present value of which is approximately $31 million of total bill reduction.

II. GREENTHERM™ PROGRAM

Q. WHAT IS RENEWABLE NATURAL GAS ("RNG")?

A. RNG is sourced from landfills, animal waste, woody biomass, crop residuals, and energy crops. In its raw form, it is called biogas, and once biogas is sufficiently cleaned and concentrated to pipeline quality, it is called biomethane. Critically, once biomethane is created from biogas sourced in this way, a "green attribute" is also created. This attribute is a separate asset from the gas itself and may be sold and joined to natural gas produced from traditional fossil sources. This asset is somewhat similar to renewable energy credits ("RECs"), the attributes that are produced with renewable-sourced electricity.

Any gas that has the green attribute, whether it is produced from biological sources or not, is then classified as RNG. In some contexts, RNG consumers use the physical molecules of biomethane produced from RNG generation sites, but more often, they do not. The green attribute is often sold to another gas supplier or utility and is then assigned to traditionally sourced natural gas. This process is common in RNG "green pricing" programs. Whether the attribute is sold to a supplier or distributor in another location, or the RNG is produced and sold in the same system, the green attribute is retired after a customer has used the RNG.

Q. WHAT IS A GREEN PRICING PROGRAM?

A. Green pricing programs are those that contain "an optional utility service that allows customers of traditional utilities to support a greater level of utility investment in renewable energy by paying a premium on their electric bill to cover any above-market costs of acquiring renewable energy resources."[2]

Q. HOW COMMON ARE RENEWABLE ENERGY GREEN PRICING PROGRAMS?

A. Green pricing programs are commonplace in the U.S.; currently, 38 states have these programs.[3] In the U.S. in 2019, these programs accounted for approximately 11.1 MWh (6.8%) of the 164 MWh of renewable energy produced through green power markets, and included roughly 1.1 million customers.[4]

---

[2] U.S. ENVIRONMENTAL PROTECTION AGENCY, Vocabulary Catalog (last updated Jan. 23, 2021), *available at* https://sor.epa.gov/sor_internet/registry/termreg/searchandretrieve/glossariesandkeywordlists/search.do (defining green pricing program).

[3] NATIONAL RENEWABLE ENERGY LABS, Voluntary Green Power Procurement (last visited Mar. 30, 2021) *available at* https://www.nrel.gov/analysis/green-power.html.

[4] Jenny Heeter and Eric O'Shaughnessy, NREL Renewable Energy Markets Conference, *Status and Trends in the Voluntary Market (2019 data)*, (Sept. 23, 2020) *available at* https://www.nrel.gov/docs/fy21osti/77915.pdf.

Q. WHAT BENEFITS DO RNG AND RNG GREEN PRICING PROGRAMS PROVIDE?

A. RNG captures methane that might otherwise escape into the atmosphere, increases fuel diversity, and provides local economic benefits in the construction of treatment and delivery infrastructure, among other benefits.[5] The availability of RNG to customers increases renewable energy options, helps meet renewable portfolio standards or carbon reduction goals, facilitates the growth of RNG production capacity, and supports green attribute markets.

Q. WHAT GREEN PRICING PROGRAMS CURRENTLY EXIST FOR RNG, AND HOW ARE THEY STRUCTURED?

A. I am aware of nine programs operating, or that will soon be operating, in North America, and two others that are in development (Avista in Washington state, and Energir in Quebec). These programs are generally available to residential and small commercial and industrial customers, and approach pricing in different ways. FortisBC in British Columbia and DTE Energy in Michigan both operate programs that offer participants a number of "blends" with which they can replace some of or all of their regular natural gas usage with RNG. For example, FortisBC program participants may select and pay for 5%, 10%, 25%, 50%, and 100% RNG blends. Summit Natural Gas of Maine operates a similar program.

[5] U.S. ENVIRONMENTAL PROTECTION AGENCY, Landfill Methane Outreach Program: *Renewable Natural Gas* (last updated Mar. 11, 2021) *available at* https://www.epa.gov/lmop/renewable-natural-gas.

Dominion Energy Utah customers are able to purchase half-dekatherm "blocks" of usage[6] and Enbridge Gas customers in Ontario pay a flat $2 fee to participate in that utility's pilot program[7]. Southern California Gas and San Diego Gas & Electric ("Sempra") is currently developing a similarly structured program that will allow participants to choose a flat fee.[8] Additionally, participants in The Energy Co-Op's program in southeast Pennsylvania, available to PECO Energy and Philadelphia Gas Works customers currently have the single option of 100% RNG replacement.[9]

Lastly, participants in NW Natural's "Smart Energy" program in Oregon can choose either a flat rate ($5.50/month) or a usage based tariff of $0.105/therm for a 100% carbon offset.[10] Vermont Gas uses this hybrid approach as well, though the flat rate can be chosen by the participant, and the usage-based cost is based on set blends (10%, 25%, 50%, 100%).[11]

---

[6] DOMINION ENERGY, Utah: Save Energy, *GreenTherm* (copyright 2020) *available at* https://www.dominionenergy.com/utah/save-energy/greentherm#.

[7] Decision and Order on Enbridge Gas Inc. Voluntary Renewable Natural Gas Program Application, Ontario Energy Board Docket EB-2020-0066 (Sept. 24, 2020) *available at* https://www.rds.oeb.ca/CMWebDrawer/Record/687754/File/document.

[8] Prepared direct Testimony of Grant Wooden on behalf of Southern California Gas Company and San Diego Gas & Electric Company, Application A.19-02-XXX (February 2019) *available at* https://www.socalgas.com/regulatory/documents/a-19-02-015/RNG%20Tariff-%20%20Testimony%20(Ch%202%20-%20Program%20-%20Wooden)%20-%20Final4.pdf.

[9] THE ENERGY CO-OP, FAQ (last visited Mar. 30, 2021) *available at* https://www.theenergy.coop/faq/.

[10] NW NATURAL, About Us: *About Smart Energy* (2021) *available at* https://www.nwnatural.com/about-us/carbon-offset-program/about-smart-energy.

[11] VERMONT GAS, VGS Renewable Natural Gas, *Program Manual Vermont Gas Systems,* Version 1.02 (updated Aug. 20, 2019) *available at* http://www.vermontgas.com/wp-content/uploads/2019/09/2019-RNG-Manual-for-electronic.pdf.

Q. HOW POPULAR ARE THESE RNG PROGRAMS?

A. As of late 2019, more than 11,000 customers were enrolled in FortisBC's program. NW Natural's program had more than 39,000 participants in 2017.[12] In 2020 DTE Energy's BioGreenGas program had more than 2,000 participants that are now being grandfathered into a new offering for which the company is estimating 20,000 additional enrollments in the next three years.[13] Vermont Gas had approximately 300 participants in 2018.[14]

Q. PLEASE DESCRIBE PSNC'S PROPOSED GREENTHERM™ PROGRAM.

A. PSNC's proposed GreenTherm™ Program is structured similarly to Dominion Energy Utah's program. Eligible customers will be able to purchase one or more half-dekatherm blocks of RNG attributes. A customer's purchase of RNG attributes are not based on customer usage, and revenues from the program will be used to cover the Company's cost of purchasing RNG attributes and administrative costs.

III. CONCLUSION

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. Nexant has worked collaboratively with PSNC to review its current conservation programs, discuss the characteristics of customers in the PSNC

---

[12] LESS WE CAN, What You Can Do, *Offset with Smart Energy* (2021) *available at* http://lesswecan.com/what-you-can-do/offset-with-smart-energy.

[13] In the matter of the application of DTE Gas Company seeking authority to amend its voluntary BioGreenGas Program and implement a new Voluntary Renewable Gas Program (VRG) pilot, MPSC Case No. U-20839 (filed June 15, 2020) *available at* https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t000000CHmZsAAL.

[14] Voluntary Renewable Natural Gas Program Technical Conference (19-057-T04) (Mary 1, 2019) *available at* https://pscdocs.utah.gov/gas/19docs/19057T04/307955TechConfPres5-1-2019.pdf.

service territory, identify energy efficiency opportunities, and achieve sustainability goals. Based on this information and Nexant's experience with natural gas conservation programs in the region and around the country, we have developed the proposed cost-effective programs to provide additional opportunities for PSNC's customers to conserve natural gas and meet their sustainability goals.

Q. DOES THIS CONCLUDE YOUR PREFILED DIRECT TESTIMONY?

A. Yes, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

MS. GRIGG: Thank you, ma'am. And I have one piece of supplemental testimony, which is the -- I move that the supplemental testimony of John D. Taylor be entered into the record as if given orally from the stand and Taylor Supplemental Exhibit 1 as both were filed on August 1st, 2021, be entered into the record.

COMMISSIONER BROWN-BLAND: All right. I have August 10th. Is that --

MS. GRIGG: That's another typo. Sorry. Yes, ma'am.

COMMISSIONER BROWN-BLAND: Just to be -- just to be clear. All right. That, without objection, will be received -- will be filed -- I'm sorry -- and entered as received.

(Taylor Supplemental Exhibit 1 was marked for identification and received into evidence.)

(Whereupon, the prefiled supplemental testimony of John D. Taylor was copied into the record as if given from the stand.)

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

SUPPLEMENTAL TESTIMONY

OF

JOHN D. TAYLOR

AUGUST 10, 2021

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

A. My name is John D. Taylor and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. I am appearing on behalf of Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or the "Company").

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

A. PSNC requested Atrium to update the fully-allocated Cost of Service Study ("COSS") that was filed in this proceeding on April 1, 2021, for the actual levels of expense and rate base as of June 30, 2021. I am sponsoring the COSS that allocates PSNC's updated gas distribution costs to its rate classes, class revenue increase apportionment, and proposed rate design.

Q. PLEASE SUMMARIZE YOUR SUPPLEMENTAL TESTIMONY.

A. In my testimony I present PSNC's updated COSS and discuss its results, present the updated revenue increase apportionment to PSNC's rate classes, and present the updated rate design proposals filed by PSNC in this proceeding. I am also sponsoring Taylor Supplemental Exhibit 1, which contains the results of the updated COSS model, the revenue targets by class, rate design proposals, and further details on the special studies utilized in the COSS. Additionally, the updated COSS has been revised to correct for a minor error in the allocation of FERC Account 385 – Industrial Measuring and Regulating Equipment.

Q. DOES THIS SUPPLEMENTAL FILING INCORPORATE ANY CHANGES IN THE METHODS UTILIZED FOR COST ALLOCATION IN PSNC'S COSS, THE APPORTIONMENT OF REVENUE INCREASE, OR THE RATE DESIGN IN THIS PROCEEDING?

A. No. The general methods employed in the update are the same as used in the Company's original filed application.

Q. DOES THIS SUPPLEMENTAL FILING INCORPORATE ANY CHANGES IN THE COST ALLOCATION FACTORS USED IN PSNC'S COSS IN THIS PROCEEDING?

A. Yes. I found a minor error in the external allocation factor for FERC Account No. 385 - Industrial M&R Stations where the actual investment for Industrial Meters and Regulators by rate class is used to allocate these costs. A portion of the investment related to the Large Quantity General Service class was inadvertently omitted in the original filing which had the effect of understating the allocation of costs to that class. I have revised the allocation factor to include the omitted portion of investment in the updated COSS. The result is an additional 0.91% of Industrial M&R related costs allocated to the Large Quantity General Service class, and a proportional decrease to the other customer classes.

Q. HAVE YOU PREPARED ANY EXHIBITS IN SUPPORT OF YOUR SUPPLEMENTAL TESTIMONY?

A. Yes. I prepared Taylor Supplemental Exhibit 1.

Q. WAS YOUR SUPPLEMENTAL EXHIBIT PREPARED BY YOU OR UNDER YOUR DIRECTION AND SUPERVISION?

A. Yes.

Q. PLEASE DESCRIBE TAYLOR SUPPLEMENTAL EXHIBIT 1.

Taylor Supplemental Exhibit 1 is comprised of the following 11 schedules:

- Schedule 1 presents the resulting allocation by rate class of PSNC's proposed updated revenue requirement based strictly on the results of the computations included in the COSS.
- Schedule 2 summarizes the updated costs allocated to PSNC's rate classes on a functionalized (e.g., by production and distribution) and classified (i.e., by demand, customer and commodity) basis.
- Schedule 3 presents the apportionment of the proposed updated revenue requirement to PSNC's rate classes based on the approach described in my direct testimony.
- Schedule 4 summarizes the selected allocation for each account in PSNC's updated revenue requirement.
- Schedule 5 shows the classification of distribution mains based on the zero-intercept analysis.
- Schedule 6 presents the derivation of external allocation factors.
- Schedule 7 shows the derivation of each rate component for each of PSNC's tariff schedules, and the corresponding revenues generated from those proposed rates.

- Schedule 8 is the proof of revenues under current and proposed rates.
- Schedule 9 shows the detailed cost functionalization and classification.
- Schedule 10 presents a summary of costs by FERC account to each customer class.
- Schedule 11 shows the detailed allocation to retail service customers for each function and classification combination in the cost of service study.

Q. PLEASE SUMMARIZE THE RESULTS OF PSNC'S UPDATED COSS.

A. The results of PSNC's updated COSS are very similar to the original COSS. Table 1 below presents a summary of the results of the Company's COSS that can be reviewed in detail in Schedule 1 of Taylor Supplemental Exhibit 1. The COSS shows an overall revenue deficiency to the Company of $49.66 million. Regarding rate class revenue levels, the rate of return results show that all classes except Medium General Service are being charged rates that recover less than their indicated costs of service.

Table 1 - Summary Results of the Company's COSS

Rate Class	Class Revenue (Deficiency)/ Excess	Rate of Return on Net Rate Base	Relative Rate of Return
Residential Service	(24,099,927)	5.98%	1.11
Small General Service	(4,286,255)	6.41%	1.19
Medium General Service	1,404,024	10.35%	1.93
Large Quantity General Service	(15,262,217)	1.96%	0.36
Large Quantity Interruptible Service	(7,420,346)	0.33%	0.06
Total Company	(49,664,720)	5.37%	1.00

Q. PLEASE SUMMARIZE THE PROPOSED APPORTIONMENT OF PSNC'S PROPOSED UPDATED REVENUE INCREASE TO ITS RATE CLASSES.?

A. The proposed apportionment of PSNC's updated revenue increase is reflected on Schedule 3 of Taylor Supplemental Exhibit 1 and in Table 2 below, wherein the relative rates of return on net rate base are shown to generally converge towards unity or 1.00 compared to the same measure calculated under present rates. In addition, the amounts of the existing rate subsidies and excesses among the Company's rate classes were generally reduced. From a class cost of service standpoint, this type of class movement, and reduction in class rate subsidies, is desirable to move class revenues and rates closer to the indicated cost of service for each rate class.

Table 2 - Comparison of Relative Rate of Return by Rate Class

Rate Class	Current Rate of Return	Relative Rate of Return	Proposed Rate of Return	Relative Rate of Return
Residential Service	5.98%	1.11	8.08%	1.07
Small General Service	6.41%	1.19	9.04%	1.19
Medium General Service	10.35%	1.93	11.72%	1.54
Large Quantity General Service	1.96%	0.36	4.55%	0.60
Large Quantity Interruptible Service	0.33%	0.06	2.27%	0.30
Total Company	5.37%	1.00	7.59%	1.00

Q. WHAT ARE THE PERCENTAGE CHANGES IN REVENUES BY RATE CLASS RESULTING FROM THE COMPANY'S PROPOSED UPDATED REVENUE APPORTIONMENT?

A. Table 3 below summarizes the proposed revenue change for each rate class and the percent change in total revenues resulting from the above-described process.

Table 3 - Proposed Class Revenue Apportionment

Rate Class	Revenues at Current Rates	Revenues at Proposed Rates	Proposed Revenue Change	Percent Change	Increase Relative to System Increase
Residential Service	359,916,326	390,683,202	30,766,877	8.55%	0.99
Small General Service	103,191,651	112,012,826	8,821,175	8.55%	0.99
Medium General Service	22,278,245	23,230,455	952,210	4.27%	0.49
Large Quantity General Service	41,664,238	48,787,441	7,123,203	17.10%	1.98
Large Quantity Interruptible Service	11,705,521	13,706,776	2,001,256	17.10%	1.98
Other Revenue	35,356,845	35,356,845	0	0.00%	-
Total Company	574,112,825	623,777,545	49,664,720	8.65%	1.00

Further, the Company's percentage changes of distribution margin revenues associated with its proposed revenue apportionment by rate class are summarized in Table 4 below. As can be seen in this table, the proposed increase to the Residential class is 0.87 times the overall system increase of 15.51%.

Table 4 - Proposed Change in Distribution Margin Revenues by Rate

Rate Class	Distribution Margin Revenues at Current Rates	Distribution Margin Revenues at Proposed Rates	Proposed Revenue Change	Percent Change	Increase Relative to System Increase	Percent of Total Distribution Margin Revenues
Residential Service	228,324,459	259,091,075	30,766,617	13.47%	0.87	70.07%
Small General Service	50,553,113	59,374,489	8,821,376	17.45%	1.12	16.06%
Medium General Service	10,299,950	11,252,188	952,238	9.25%	0.60	3.04%
Large Quantity General Service	23,580,397	30,703,645	7,123,248	30.21%	1.95	8.30%
Large Quantity Interruptible Service	7,363,292	9,364,534	2,001,241	27.18%	1.75	2.53%
Total Company	320,121,211	369,785,931	49,664,720	15.51%		100.00%

Q. HAVE YOU PROVIDED A SUPPLEMENTAL SCHEDULE DETAILING THE PROPOSED RATES AND CORRESPONDING REVENUES?

A. Yes. Schedule 7 of Taylor Supplemental Exhibit 1 shows the derivation of each rate component for each of PSNC's tariff schedules and the corresponding revenues generated from those proposed rates.

Q. DOES THIS COMPLETE YOUR PREFILED SUPPLEMENTAL TESTIMONY?

A. Yes, although I reserve the right to supplement further or amend my testimony before or during the Commission's hearing in this proceeding.

MS. GRIGG: Thank you. And now we'll move to the rebuttal testimonies and request that the following rebuttal testimonies be moved into the record and exhibits be marked as prefiled as they were filed -- hopefully I have this right this time -- October 7th, 2021.

And that would be the rebuttal testimony of Michael B. Phibbs, consisting of ten (10) pages and Phibbs Rebuttal Exhibits 1 and 2; the rebuttal testimony of John J. Spanos, consisting of 33 pages; the rebuttal testimony of John D. Taylor, consisting of 24 pages, as well as Taylor Rebuttal Exhibits 1 and 2; and the rebuttal testimony of Regina J. Elbert, consisting of eight (8) pages; and request that that testimony be entered into the record and move the exhibits into evidence.

COMMISSIONER BROWN-BLAND: And I think you -- you did include witness Spanos rebuttal, correct?

MS. GRIGG: Yes, ma'am. Consisting of 33 pages.

COMMISSIONER BROWN-BLAND: All right. Without objection, those rebuttal testimonies identified by counsel will be received into the record, treated as if given orally from the witness stand, and the exhibits identified in her motion, those will be received into evidence at this time and marked as prefiled.

(Phibbs Rebuttal Exhibits 1 and 2 and Taylor

Rebuttal Exhibits 1 and 2 were marked for identification and received into evidence.)

(Whereupon, the prefiled rebuttal testimony of Michael B. Phibbs, the prefiled rebuttal testimony of John J. Spanos, the prefiled rebuttal testimony of John D. Taylor and the prefiled rebuttal testimony of Regina J. Elbert were copied into the record as if given from the stand.)

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

REBUTTAL TESTIMONY

OF

MICHAEL B. PHIBBS

OCTOBER 7, 2021

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

A. My name is Michael B. Phibbs, and my business address is 120 Tredegar Street, Richmond, Virginia 23219. I am General Manager – Financial and Business Services. I am employed by Dominion Energy Services, Inc. When I filed my direct testimony, I was employed as Director – Corporate Finance and Assistant Treasurer for Dominion Energy, Inc. ("DEI") and subsidiaries including Public Service Company of North Carolina, Inc. ("PSNC" or the "Company"). On September 1, 2021, I assumed my new position.

Q. ARE YOU THE SAME MICHAEL PHIBBS WHO PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. Yes.

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

A. The purpose of my rebuttal testimony is to respond to the testimony of Public Staff witness John R. Hinton and Carolina Utility Customers Association witness Kevin W. O'Donnell regarding the Company's proposed capital structure and to Mr. Hinton's testimony regarding cost of debt. On proposed capital structure, I will primarily address Mr. Hinton's assertions that the Company is earning excessive returns not required to maintain credit ratings and his and Mr. O'Donnell's use of hypothetical capital structures.

Q. WHAT IS THE CAPITAL STRUCTURE THAT THE COMPANY PROPOSES TO USE IN THIS PROCEEDING?

A. The Company's original filing proposed 43.79% long-term debt, 1.33% short-term debt, and 54.88% common equity, based on PSNC's projected capital structure as of June 30, 2021. In its supplemental filing on August 10, 2021, the Company proposed a capital structure of 43.80% long-term debt, 1.34% short-term debt, and 54.86% common equity, based on the actual capital structure as of June 30, 2021. While both Mr. Hinton and Mr. O'Donnell addressed the original proposed 54.88% common equity ratio, my rebuttal testimony assumes that their opinions would be the same for a common equity ratio of 54.86%. Likewise, the statements I made in my direct testimony supporting the Company's need for 54.88% common equity apply to a common equity of 54.86%.

Q. MR. HINTON DESCRIBES THE COMPANY'S PROPOSED COMMON EQUITY RATIO AS EXCESSIVE. DO YOU AGREE?

A. No, I do not. As explained in my direct testimony, the proposed common equity ratio balances the Company's financing needs to fund operations to meet its service obligations and to achieve credit rating objectives that enable efficient access to capital at reasonable terms.

Q. WHAT IS THE PRIMARY BASIS FOR MR. HINTON'S ASSERTION THAT THE COMPANY IS EARNING EXCESSIVE RETURNS AT A 54.88% COMMON EQUITY RATIO?

A. Generally, Mr. Hinton argues that the Company does not require a common equity ratio of 54.88% in order to maintain its current credit ratings by referencing financial metric data from Moody's Investment Services ("Moody's").

Q. HOW DOES MR. HINTON DESCRIBE WHAT IS NECESSARY TO MAINTAIN THE COMPANY'S CURRENT CREDIT RATINGS?

A. Mr. Hinton selectively highlights certain Moody's financial metrics, namely Cash Flow Operations (pre-working capital)/Debt ("CFO pre-WC/debt"), in making his argument. He asserts that, because the financial metric has been above and below 15%, the Company does not require the 54.88% common equity ratio.

Q. DO YOU AGREE WITH MR. HINTON'S ASSERTION?

A. I do not. Mr. Hinton ignores that Moody's has stated in published reports that the Company would be at risk of a downgrade if the CFO pre-WC/debt financial metric "remains below 15%", which it has been for the past three years. Therefore, 15% is the minimum requirement, and values above that figure are indicative of what is required to maintain PSNC's current rating.

Mr. Hinton shows year-ending data for 2017-2020 and a last twelve-month view based on March 31, 2021. In 2017, Moody's stated 20.4% metric was during a time in which the Company was rated A3, and Moody's reports suggested 20% was a threshold at which Moody's could reasonably expect to consider a downgrade – an entirely different circumstance that is not relevant to the current status of the Company. See Phibbs Rebuttal Exhibit 1 for a copy of Moody's July 23, 2018 report, which included verbiage pertaining to the 20% threshold.

Subsequent to 2017, the financial credit metric of the Company fell like many others in the industry as the effects of federal tax reform lowered rates to customers and thus cash flow, with the metric reported as Mr. Hinton testifies at 12.1%, 12.6%, and 14.3% for the three consecutive years ending 2018, 2019, and 2020. In January 2020, Moody's downgraded the Company's credit rating from A3 to Baa1 due to the continuance of weakened financial metrics in the 2018-2020 period.

It is important to note that, despite the downgrade, Moody's has praised Dominion Energy's efforts of ensuring balance sheet strength as a "supportive parent" and mentioned that the parent company had "refrained from extracting dividends from the utility" and contributed equity as "a show of parental credit support and conservative financial policies for PSNC." See Phibbs Rebuttal Exhibit 2 for a copy of Moody's February 8, 2021 report. It is on this basis, as well as the expectation of "supportive regulatory treatment" within this general rate case, that the Company believes Moody's did not consider a further downgrade notch, as the expectation would be that the Company would maintain above a 15% financial metric in the future, despite not exhibiting this level from 2018-2020.

I also note that the Mr. Hinton's use of March 31, 2021 financial metric data is selective. The published metric by Moody's is actually 19.7%. See page 1 of Phibbs Rebuttal Exhibit 3. Further, while the last twelve month metrics are an indicator of interim performance, Moody's typically places more weight on year-end metrics to be determinative of credit actions. By using the March 31, 2021 metric in association with all other metrics at respective December 31 year-ends, Mr. Hinton introduces bias to where metrics may not be assessed on an apples-to-apples basis, as items such as regulatory assets and liabilities may ebb and flow throughout the year. This could unduly influence metrics utilizing differing time periods. In fact, as shown on page 2 of Phibbs Rebuttal Exhibit 3, the associated credit ratio for the twelve months ended June 30, 2021, is only 15.1%, which is very close to the minimum threshold to prevent further credit rating degradation, and is not indicative of excessive returns.

To summarize the above points, in order to maintain current credit ratings at Moody's, the Company needs to demonstrate the ability to maintain at least a 15% CFO pre-WC/debt ratio. The Company has not met this metric level at year end in the past three years. With supportive actions that Moody's has noted, as well as the expectation of supportive regulatory treatment, the Company believes it is now on track to do so. Those supportive Company actions, namely infusing equity to balance the capital structure and forgoing dividends through the end of 2020, has resulted in an actual filed capital structure of 54.86%, which the Company believes is necessary and prudent to maintain adequate access to capital, support current credit ratings, and provide a balanced approach to funding the necessary infrastructure to meet its service obligations.

Q. WHAT COMMON EQUITY RATIOS DO MR. HINTON AND MR O'DONNELL RECOMMEND FOR PSNC?

A. Mr. Hinton recommends a common equity ratio of 50.90% for PSNC. He uses a hypothetical capital structure based on the average capital structures approved in general rate cases for LDCs in 2020 and 2021 as reported by Standard and Poor's Capital IQ and shown on Hinton Exhibit 5. I note that Mr. Hinton admitted that he had departed from his usual practice of recommending a capital structure based on a 13-month historical average, which would have resulted in using a common equity ratio of 53.65% as shown on Hinton Exhibit 4. Mr. Hinton offered no explanation for this departure.

Mr. O'Donnell uses a 50% hypothetical common equity ratio in his testimony.

Q. IN YOUR VIEW IS THE USE OF A HYPOTHETICAL CAPITAL STRUCTURE TYPICAL?

A. No, it is not. As Company witness Nelson testifies, the filed capital structure of 54.86% is within the range of prudent capital structures approved in other peer utility cases, and most reflective of our current financial position. Mr. Hinton himself describes that typically he would recommend a 13-month average common equity ratio, or an actual 53.65% common equity ratio in this preceding. Using a hypothetical capital structure, or one based simply on what was approved previously emanating from time periods which may not have similar facts and circumstances as the current period, would create inconsistencies between how a Company is actually funded versus the capital on which it may earn.

Q. WHAT IS YOUR OPINION OF USING A 13-MONTH AVERAGE CAPITAL STRUCTURE, WHICH MR. HINTON DESCRIBES AS HIS TYPICAL RECOMMENDATION?

A. It would be most prudent to reflect the actual capital structure at the time of the rate case preceding, which is most reflective of the Company's capital mix. However, a 13-month average capital structure at least is based on the actual financial position of the Company and also reflects relatively recent data. Therefore, I would view that methodology as one that is grounded in sound logic as compared to a hypothetical or "last approved" methodology.

Q. WHAT DO YOU BELIEVE THE EFFECT WOULD BE OF ALLOWING MR. HINTON'S IMPUTED COMMON EQUITY RATIO OF 50.90%, OR MR. O'DONNELL'S 50% IMPUTED CAPITAL RATIO?

A. Imputation of a capital structure would be arbitrary and present significant financial harm to the Company.

My testimony already details that in the past three years, the Company has not maintained necessary financial metrics to secure its credit rating and has experienced a downgrade during a time when its base rates were authorized with a 52% common equity ratio. Mr. Hinton appears to agree that it is in the Company's best interests to maintain its current credit rating, as he looks to triangulate equity ratios that would be supportive of this rating within his testimony. Actions undertaken to solidify the Company's credit standing, which Moody's has viewed favorably, have resulted in a higher common equity ratio than 52%. If the Company could not earn on this prudent and supportive capital structure, and in fact be forced to earn below prior common equity figures despite an increase in the actual common equity ratio, it would send a negative signal to investors and credit agencies alike that North Carolina is not providing "supportive regulatory treatment." A supportive regulatory environment generally entails earning fair returns on a reasonable capital structure. Adopting either of these imputed capital structures would leave the Company with significant equity capital which it cannot earn a return on, could jeopardize current credit ratings, and would not recognize the actions the Company has taken to solidify its balance sheet and ratings since the Company's change in ownership. In addition, Mr. Hinton's approach would harm the Company should that same balance sheet and ratings be deemed inadequate by credit agencies in the form of imposing replacement cost of debt imputations, which he also advocates in his testimony.

Q. WHAT IS PSNC'S CURRENTLY AUTHORIZED COMMON EQUITY RATIO?

A. PSNC's current rates are based on a Commission approved common equity capitalization ratio of 52%.

Q. WHAT DO YOU BELIEVE THE COMMISSION SHOULD DO REGARDING THE COMMON EQUITY RATIO?

A. I believe the Commission should accept the 54.86% common equity ratio included in the Company's supplemental filing, as that represents the most updated view of the Company's balance sheet. That said, any exploration of alternatives to the 54.86% actual common equity ratio must be grounded in recent actual data of the Company, such as a 13-month average view. Certainly, the Commission should not embrace Mr. Hinton's and Mr. O'Donnell's proposals to deteriorate the Company's financial position below its current authorized equity capitalization ratio of 52%.

Q. DO YOU AGREE WITH MR. HINTON'S IMPUTATION OF A COST OF DEBT OF 4.45% DUE TO THE CREDIT DOWNGRADE OF THE COMPANY BY MOODY'S?

A. I do not. Mr. Hinton rightly acknowledges, as does the Company, that a condition of the Dominion Energy, Inc. and SCANA merger was that in the event of a credit rating downgrade, PSNC customers should be held harmless, and a replacement cost of debt utilized if customers are harmed by a resulting higher cost of debt on subsequent issuances. However, Mr. Hinton does not provide any Company-specific facts to support his assertion that the Company's cost of debt was harmed – he merely utilizes bulk average data in the form of Mergent Inc.'s research, as well as his previous investigations into another utility that was downgraded.

In response to a Public Staff data request, the Company explained that there was no pricing degradation in debt issuances after the January 2020 Moody's downgrade. This response provided data showing that the National Association of Insurance Commissioners rating of PSNC did not change, which directly impacts most private debt investors' cost of capital. The data also showed quantitatively that the most recent PSNC debt issuance in 2021 priced better on a credit spread basis relative to the investment grade utility index than any issuance since 2016, well before the downgrade. Mr. Hinton does not offer any specific data to support his conclusion; rather he found the Company's view "unpersuasive."

Q. WHAT DO YOU PROPOSE THE COMMISSION DO REGARDING THE LONG-TERM DEBT RATE?

A. I encourage the Commission to consider that the data specific to PSNC in this particular case shows no harm to ratepayers from the January 2020 Moody's downgrade. I recommend that the Commission accept the 4.48% cost of long-term debt proposed by the Company, which is lower than the embedded cost of long-term debt in the Company's original application due to the 2021 refinancing.

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes, it does, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

REBUTTAL TESTIMONY

OF

JOHN J. SPANOS

OCTOBER 7, 2021

TABLE OF CONTENTS

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is John J. Spanos, and my business address is 207 Senate Avenue, Camp Hill, Pennsylvania 17011.

Q. IN WHAT CAPACITY ARE YOU EMPLOYED?

A. I am President of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming").

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or the "Company").

Q. ARE YOU THE SAME JOHN J. SPANOS WHO FILED DIRECT TESTIMONY IN THE ORIGINAL FILING OF THE APPLICATION IN DOCKET NO. G-5, SUB 632?

A. Yes.

Q. WHAT IS THE PURPOSE OF YOUR REBUTTAL TESTIMONY?

A. The purpose of my rebuttal testimony is to respond to the depreciation proposals that are set forth in the testimony of Public Staff witness Roxie McCullar. There is one primary depreciation-related issue raised by Ms. McCullar. This is the method of net salvage[1] estimation and resultant net salvage estimates for

[1] Net salvage is gross salvage less cost of removal. Because cost of removal frequently exceeds gross salvage, net salvage is often a negative amount. In my testimony, when I refer to "higher net salvage" I mean more negative net salvage or higher cost of removal.

two of the largest plant accounts and the resulting effect on depreciation expense.

Public Staff witness McCullar's net salvage estimates for Account 476.10, Mains – Plastic and Account 476.30, Mains – Steel are largely informed by a method of analysis that does not form a sound basis for estimating net salvage. This results in Ms. McCullar reducing the net salvage estimates for each of these accounts by 20 percent, which results in levels that are below reasonableness as compared to the historical ratio of costs to retire the associated plant. This inappropriate and unsupported method has previously been rejected by this Commission.

II. MASS PROPERTY NET SALVAGE

A. The Public Staff Has Not Proposed an Appropriate Method to Estimate Net Salvage

Q. WHAT IS NET SALVAGE?

A. Net salvage as used in depreciation is defined as gross salvage less cost of removal. When an asset is retired it may have scrap or reuse value, which is gross salvage. There is also a cost to retire the asset. Removal costs can occur even if an asset is not physically removed if there are costs associated with retiring it. For example, when retiring a gas main there are typically costs to purge gas from the main and cut and cap the pipe even though the main may not be physically removed from the ground.

Most types of utility property typically experience negative net salvage, meaning that the cost of removal exceeds gross salvage. It is also important to understand that net salvage recorded in a given year is a function of the amount of property retired. For example, it would cost more to retire 1,000 gas mains in a given year than to retire 100 gas mains. The method I have used to estimate net salvage in the depreciation study, which is the industry standard method for estimating future net salvage, recognizes this relationship between net salvage and retirements. Ms. McCullar's estimates are informed by a methodology that is not supported by depreciation authorities and does not recognize this important relationship. This is an important flaw in Ms. McCullar's approach to estimating net salvage, since there has been a trend towards increased retirement activity which will result in higher levels of net salvage.

Q. WHAT HAS MS. MCCULLAR PROPOSED FOR NET SALVAGE?

A. Ms. McCullar proposes different net salvage estimates from the Company's proposal for two subaccounts of distribution plant. Her proposed method for these two accounts is based on different practices than were used for the other accounts. In each case, the difference between her estimate and the Company's is that she uses an approach to estimate net salvage that does not have a sound mathematical basis and is not supported by depreciation authorities. Rather than using the accepted approach of expressing net salvage as a percentage of retirements, Ms. McCullar's approach is based on the dollar amount of net salvage recorded in recent years. Ms. McCullar ignores the fact that over $30 million in retired plant has occurred for distribution mains with an associated $12.1 million cost of removal. Her analysis is based on a premise that annual depreciation accruals for net salvage should be closer to the average net salvage dollar amounts that have been recorded in recent years.

Ms. McCullar's proposal is, therefore, based on an incorrect premise that annual depreciation accruals for net salvage should have a relationship to recent net salvage costs, and perhaps should be the same as or similar to recent net salvage costs. However, if depreciation accruals were determined to be the same as recent net salvage costs, such an approach would mean that net salvage is recovered in a manner more consistent with that of an operating expense rather than as a capital cost because it would recover net salvage as it occurs rather than over the lives of the Company's assets.[2]

I do recognize that Ms. McCullar has not proposed to set depreciation expense for net salvage to be the same as recent net salvage costs. Instead, she has arbitrarily established net salvage depreciation accrual amounts to be some multiple higher than recent net salvage costs. However, this does not rectify the problems with her analysis and proposal. Ms. McCullar provides no

[2] Ms. McCullar appears to argue in footnote 21 on page 21 of her testimony that her proposal is not a change from an accrual basis to a cash basis because she is "not recommending or implying that the depreciation accrual no longer be credited to the Accumulated Provision for Depreciation or that the net salvage costs be 'expensed'." However, merely recording costs to accumulated depreciation does not meet the requirements of accrual accounting if the timing of the recording of these costs does not align with the time periods in which they provide service. Recognizing net salvage when it is incurred (i.e., when the money is spent or received), rather than over the life of the related property, is more consistent with cash basis accounting than accrual accounting. As a result, a net salvage method that only recovers net salvage costs as they occur is not consistent with accrual accounting for net salvage.

support for the specific multiple that she uses for each account, nor does she provide any evidence for why this multiple is superior to any other number.

Q. HAS MS. MCCULLAR PROVIDED A SYSTEMATIC AND RATIONAL BASIS FOR HER PROPOSALS?

A. No. Ms. McCullar discusses the impact of inflation on traditional methods of estimating net salvage and also discusses her comparison of net salvage costs to net salvage accruals. However, it is not clear how any of these factors led to her specific proposals and, as a result, it is difficult to respond to the specific bases of her recommendations. My testimony will respond to the concepts she discusses in support of her recommendations and explain that these concepts are not sound mathematically and are inconsistent with and not supported by the authorities she cites in her testimony. I first discuss why an approach of comparing net salvage costs to net salvage accruals does not provide a reasonable basis for estimating net salvage and then will address her discussion related to inflation in net salvage estimates and explain that authorities, including those cited in her testimony, support the approach I have used to estimating net salvage.

B. The Public Staff's Proposal Will Fail to Recover Future Net Salvage Costs Over the Lives of the Company's Assets

1. Net Salvage Accruals Should Not Be Expected to Be the Same as Recent Net Salvage Costs

Q. MS. MCCULLAR BASES HER NET SALVAGE ESTIMATES ON A COMPARISON OF RECENT NET SALVAGE COSTS TO THE PROPOSED

NET SALVAGE ACCRUALS. IS THIS A REASONABLE BASIS FOR THE ESTIMATION OF FUTURE NET SALVAGE?

A. No. The underlying premise of Ms. McCullar's approach is that net salvage accruals should be similar to, if not the same as, recent net salvage costs. This premise is incorrect. Net salvage accruals are intended to allocate future net salvage costs over the life of a Company's assets, and therefore should not be expected to be the same as recent net salvage costs.

Q. IS THERE REASON TO EXPECT THAT FUTURE NET SALVAGE WILL BE HIGHER ON A DOLLAR BASIS THAN CURRENT AND RECENT LEVELS OF NET SALVAGE?

A. Yes. There are several conceptual reasons why one should not expect future net salvage to occur at a similar dollar level to current or recent costs, which I will discuss in more detail below. Additionally, recent history and future expectations support that the level of retirements will increase, which will also create an anticipated increase in cost of removal and a larger increase in net salvage accruals.

Ms. McCullar's net salvage methodology fails to recognize that the level of net salvage is not static and will change over time. Due to this flaw, Ms. McCullar's methodology will not recover the expected increases in future net salvage until after they occur. This will result in intergenerational inequity as future customers will be paying the costs of assets that have already been retired.

Q. PLEASE PROVIDE AN EXAMPLE TO DEMONSTRATE THAT, IN GENERAL, NET SALVAGE ACCRUALS SHOULD NOT BE THE SAME AS CURRENT NET SALVAGE COSTS.

A. Consider an example of a single gas main segment that costs $5,000, has a service life of 65 years, and for which the cost to retire the service, net of any salvage, is $2,000. To properly allocate these net salvage costs in equal amounts over the asset's 65-year service life through depreciation expense, depreciation accruals for net salvage would need to be $31 per year to recover the full $2,000 future net salvage costs.

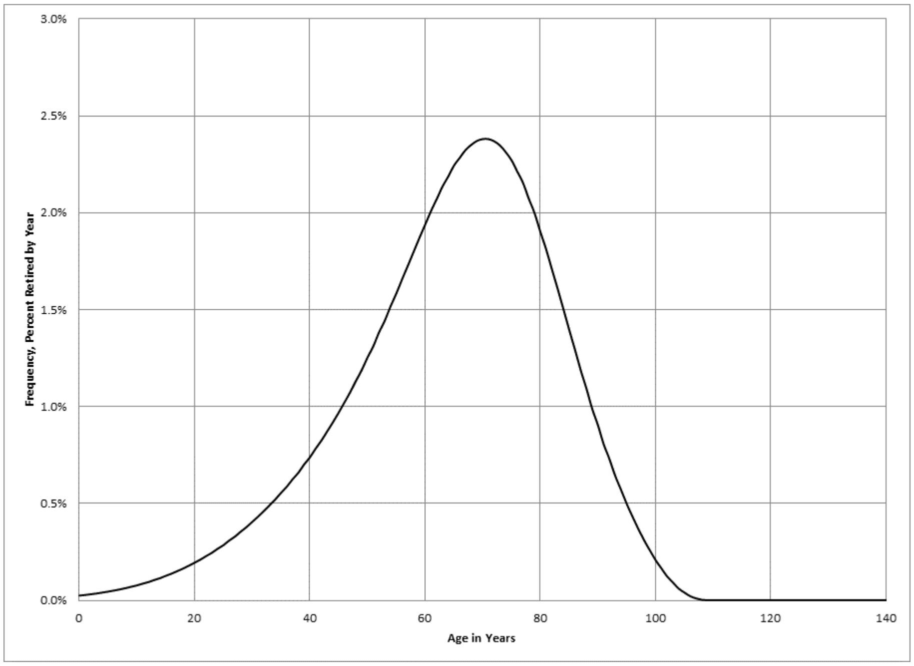
However, recovering $31 per year in net salvage means that the net salvage accruals will not be the same as the dollar levels of net salvage recorded in a given year. In each year of the gas main's life, the recorded amount of net salvage would be $0. When the asset is eventually retired in year 65, the recorded net salvage would be $2,000. Using accrual accounting and the straight-line basis, the depreciation accruals for net salvage would be the same $31 amount each year, as the net salvage costs are allocated in equal amounts over the main's life. By allocating the capital costs for net salvage equally over its service life, customers are equitably charged for the cost of the service provided by the asset.

In contrast, Ms. McCullar's approach would be inequitable. Her approach would charge customers for none of the net salvage costs from years 1 through 64 and then require customers in year 65 (or shortly after year 65) to bear the entire cost to retire the gas main once it is retired. This occurs because Ms. McCullar's method is based on the dollar level of costs that have been recorded in the recent past, which in this example is $0 until year 65. This demonstrates that the traditional accrual method is equitable to customers, whereas her approach would inappropriately defer net salvage costs to customers who receive no service from the asset.

Q. THE EXAMPLE ABOVE WAS FOR A SINGLE UNIT. WOULD THE SAME CONCEPTS APPLY TO A GROUP OF PROPERTY?

A. Yes. Consider a group of gas main segments, each of which has the same cost of installation and retirement as for the single-unit example. This time I will use an average service life of 65-years, which corresponds to the 65-R3 survivor curve used for both my and Ms. McCullar's recommended depreciation rates for Account 476.10, Mains – Plastic. If 10,000 gas main segments were installed in the year 2020, then the total original cost of this group of services would be $50 million. For a group of assets, there is typically a range of lives. Some gas mains are retired prior to the average service life and some survive longer than the average. The 65-R3 survivor curve for these assets experiences retirements consistent with the pattern shown in Figure JJS-1 below.

Figure JJS-1: Frequency of Retirements by Age for 65-R3 Survivor Curve

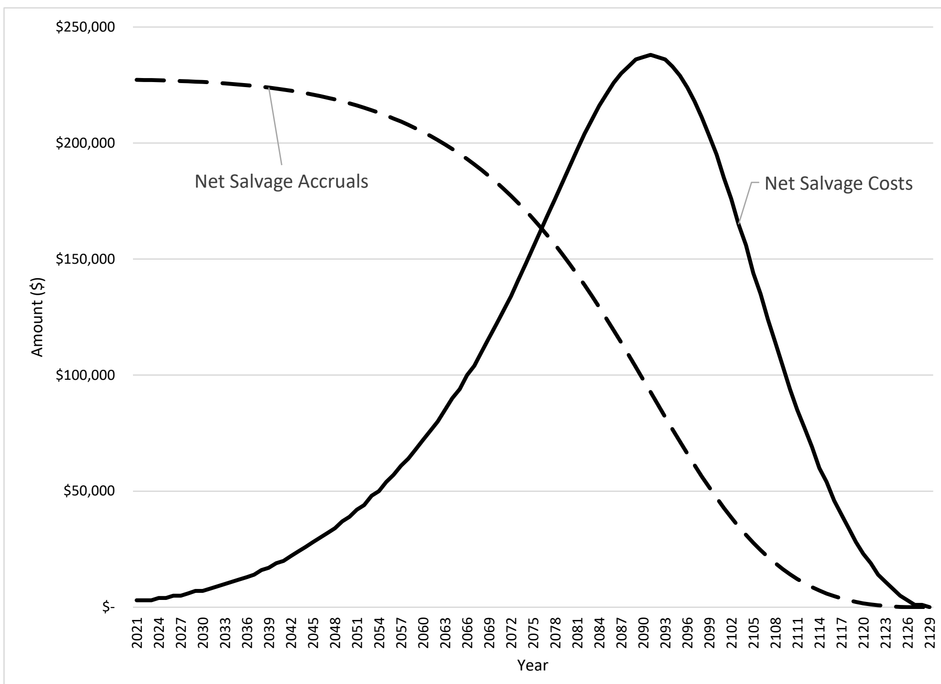


The chart shows the percentage of the 2020 assets that will be retired each year. For example, the chart shows that approximately 0.03% of the assets will retire at age 20. Based on the starting balance of 10,000 gas main segments, this means that about three gas main segments would retire at age 20. The peak of the curve occurs at age 70, at which point the largest number of retirements will occur. Specifically, of the 10,000 gas main segments originally installed, 240 will retire at age 70. That is, more than eighty times as many gas main segments will be retired at age 70 than at age 20.

Q. DOES THE DISPERSION OF SERVICE LIVES FOR A PROPERTY GROUP DEMONSTRATE THAT NET SALVAGE COSTS WILL BE HIGHER IN SOME YEARS THAN IN OTHER YEARS?

A. Yes. Continuing the example from the previous question, the net salvage cost for a single gas main is $2,000. If retirements are more than eighty times larger at age 70 than at age 20, then net salvage costs would similarly be more than eighty times greater. This is illustrated in Figure JJS-2 below, which shows the net salvage cost by year.

Figure JJS-2: Net Salvage Accruals and Net Salvage Costs by Year



Q. PLEASE EXPLAIN THE NET SALVAGE COSTS SHOWN IN FIGURE JJS-2.

A. The solid black line shows the net salvage cost by year. Contrary to the assumptions of Ms. McCullar's net salvage proposal, the total net salvage cost incurred is not the same in each year. The net salvage costs are instead a function of the retirements that occur each year, and for this reason the net salvage costs follow the frequency curve shown in Figure JJS-1. For example, net salvage costs for vintage 2020 are much higher in the years 2060 through 2090 than they are in earlier years. This demonstrates that the approach used by Ms. McCullar will fail to capture the higher future net salvage costs, because net salvage costs are not the same in each year. Looking backwards only at net salvage recorded in recent years does not provide a reasonable basis for estimating future net salvage.

Q. PLEASE EXPLAIN THE NET SALVAGE ACCRUALS SHOWN IN FIGURE JJS-2.

A. Figure JJS-2 also shows the depreciation accruals for each year that are needed to properly recover the net salvage costs for the assets in the example over their service lives. The net salvage accruals follow the survivor curve for this account, and the same amount is accrued for each unit of service provided by the group. Figure JJS-2 demonstrates that the depreciation accruals for net salvage should not be expected to be the same as net salvage costs. Instead, the accruals for net salvage are higher than the annual net salvage costs for about the first 35 years, at which point the net salvage costs begin to exceed the net salvage accruals. If net salvage costs are allocated on a straight-line basis for the group of 10,000 gas main segments, then the net salvage accruals should be expected to be different from the net salvage costs incurred in a given year.

Q. WHAT DOES THIS EXAMPLE ILLUSTRATE WITH REGARD TO MS. MCCULLAR'S METHODOLOGY?

A. This example demonstrates that Ms. McCullar's methodology is based on a flawed concept. Net salvage accruals and net salvage costs at each age are not the same, and for this reason her approach and analysis do not provide a reasonable basis for accruing for future net salvage. The accruals resulting from her approach would track the solid line labeled "Net Salvage Costs" in Figure JJS-2. This would result in net salvage costs being deferred, and most of the costs would be paid by customers after the year 2057, at which time less than half of the assets have already been retired.

Q. ONE OF MS. MCCULLAR'S CRITICISMS OF THE TRADITIONAL METHOD FOR NET SALVAGE IS THAT IT INCLUDES FUTURE INFLATION. IN THE EXAMPLE PROVIDED IN THIS SECTION, DO NET SALVAGE ACCRUALS EXCEED NET SALVAGE COSTS DUE TO INFLATION?

A. No. In this example, the cost to retire a gas main segment remains constant over the life of the property group. That is, for this example, inflation has no impact on net salvage accruals or net salvage costs. Net salvage accruals exceed net salvage costs in many years due to the need to accrue for future net salvage, not due to inflation.

Q. THIS EXAMPLE WAS FOR A SINGLE VINTAGE. DO THE SAME CONCEPTS APPLY TO REAL WORLD PROPERTY ACCOUNTS THAT INCLUDE MANY VINTAGES?

A. Yes. For most real-world accounts, net salvage accruals are higher than recent net salvage costs. Because utility systems have grown over time, a Company's assets are typically newer, on average, than the average service life. Just as the net salvage accruals exceed net salvage costs prior to the average service life (i.e., for the first 65 years) in Figure JJS-2, net salvage accruals for real-world property groups typically exceed recent net salvage costs.

2. Ms. McCullar's Approach Does Not Properly Allocate Net Salvage Costs

Q. PLEASE EXPLAIN HOW NET SALVAGE IS ESTIMATED USING THE TRADITIONAL METHOD OF ESTIMATING NET SALVAGE.

A. When using the traditional method of estimating net salvage, the analysis of historical net salvage data is performed by comparing historical net salvage to historical retirements. Net salvage (and its components, cost of removal and gross salvage) is expressed as a percentage of retirements for each year and for longer term periods. The traditional method does not focus on the dollar amount of net salvage recorded, as Ms. McCullar does. Instead, it properly recognizes that the dollar level of net salvage will tend to vary based on the level of retirements recorded in a given year.

Q. PLEASE PROVIDE AN EXAMPLE TO DEMONSTRATE THAT, UNLIKE MS. MCCULLAR'S PROPOSAL, THE TRADITIONAL METHOD WILL PROPERLY ESTIMATE NET SALVAGE.

A. To demonstrate this concept, consider a utility that has 100,000 gas main property units, for which the original cost of each is $5,000 and the cost of removal, net of salvage, is $2,000. Thus, the total future net salvage would be $200 million (100,000 x $2,000). If the average service life for gas mains were 65 years, then the annual accruals for the net salvage for these gas main segments would approximate $3.08 million ($200 million divided by 65). That is, a $3.08 million annual accrual amount is the correct amount to recover the future net salvage of $200 million for these gas main segments over their service lives. This is illustrated in Table JJS-2 below.

Table JJS-2: Quantities, Costs and Average Service Life for Group of Gas Main Segments

Number of Gas Main Segments	100,000
Original Cost per Gas Main Segment	5,000
Plant in Service	500,000,000
Net Salvage Per Gas Main	2,000
Future Net Salvage	200,000,000
Average Service Life	65
Net Salvage Accruals	3,076,69200

Q. PLEASE EXPLAIN HOW NET SALVAGE WOULD BE ESTIMATED USING MS. MCCULLAR'S METHOD AND THE TRADITIONAL METHOD.

A. As discussed in Section II.A, the number of services retired in a given year will vary based on the age of the assets and the survivor characteristics of the assets in the account. Consider a scenario in which the Company has retired an average of 1,000 gas main segments per year for the last five years. This would mean that net salvage was, on average, $2,000,000 per year (1,000 x $2,000). If one were to use Ms. McCullar's approach and establish a net salvage accrual based on this average cost of $2,000,000, then the Company would recover $2,000,000 per year through depreciation expense for net salvage. The result is that the Company would not recover the necessary $200 million in future net salvage and instead would only recover $130 million. Thus, Ms. McCullar's approach would fail to properly recover the future net salvage costs for the Company's assets.

In contrast, using the traditional method, the result would be the proper recovery of the full $200 million in future net salvage costs. The average net salvage recorded for this period would be $2,000,000 and the retirements would be on average $5 million (1,000 x $5,000). Net salvage is divided by the original cost of the retirements. Thus, the traditional net salvage analysis would indicate a net salvage percent of negative 40 percent ($2 million divided by $5 million). With a 65-year average service life, the use of a negative 40 percent net salvage estimate would correctly produce annual accruals for net salvage of $3.08 million[3] and would recover the full $200 million in future net salvage over the lives of the assets.

Q. PLEASE EXPLAIN THE IMPLICATIONS OF MS. MCCULLAR'S METHOD AND THE TRADITIONAL METHOD IF A HIGHER NUMBER OF SERVICES HAD BEEN RETIRED IN THE LAST FIVE YEARS.

A. Consider a scenario in which the Company retired an average of 4,000 gas main segments per year for the most recent five years, resulting in an average net salvage of $8 million per year (4,000 x $2,000). If Ms. McCullar's approach were used then the Company would recover $8 million per year through depreciation for net salvage, which would result in a recovery of $520 million over the lives of the gas mains, which is too much.

If the traditional method were used, then the average dollar amount of $8 million for net salvage would be divided by the average retirement amount of $20 million (4,000 x $5,000). This too would indicate a net salvage percent of negative 40 percent and result in the correct depreciation accruals.

Q. WHAT DOES THIS EXAMPLE DEMONSTRATE WITH REGARD TO MS. MCULLAR'S METHOD?

A. This example further demonstrates the basis of Ms. McCullar's approach, that net salvage accruals should be based on the dollar level of recent net salvage

[3] $500 million plant in service multiplied by 40 percent divided by 65 years is approximately $3.08 million.

costs, is fundamentally flawed. The dollar amount of recent net salvage costs is not a reasonable basis for estimating future net salvage because it does not consider the number of assets that were retired over the same time period. In both scenarios discussed above, Ms. McCullar's method fails to correctly allocate the future net salvage costs of the Company's assets. Ms. McCullar's approach is dependent on the amount of assets retired in recent years and, as a result, will not recover the correct amount of net salvage.

In contrast to Ms. McCullar's method, this example demonstrates that the traditional method determines the correct future net salvage and properly allocates net salvage over the lives of the assets. By properly recognizing the relationship of net salvage to retirements, the traditional method incorporates the fact that retirements do not occur at the same level in each year and provides a reasonable basis for the estimation of future net salvage.

C. <u>Ms. McCullar's Proposed Net Salvage Method Is Not Supported by Depreciation Authorities</u>

1. Authoritative Depreciation Texts Do Not Support Ms. McCullar's Proposed Net Salvage Method

Q. MS. MCCULLAR CITES TO TWO DEPRECIATION TEXTS IN HER TESTIMONY. DO THESE TEXTS SUPPORT HER APPROACH?

A. No. The two texts cited by Ms. McCullar are the National Association of Public Regulatory Utility Commissioners' ("NARUC") Public Utility Depreciation Practices (the "NARUC Manual") and Depreciation Systems by Wolf and Fitch ("Wolf and Fitch"). Her presentation of selected quotes from these texts could give the incorrect impression that either text expresses concern with the traditional approach for estimating net salvage or with the concept that there is an implicit level of inflation incorporated in the traditional net salvage analysis. However, neither actually supports her proposed methodology. Instead, each supports the traditional method. Both texts explain that net salvage should be accrued over the life of the related property and should be estimated using the traditional method of net salvage analysis in which net salvage is expressed as a ratio of retirements.

Q. PLEASE EXPLAIN.

A. First, both textbooks explain that net salvage should be recovered over the life of the related assets. For example, the NARUC Manual states at page 157:

> Historically, most regulatory commissions have required that both gross salvage and cost of removal be reflected in depreciation rates. The theory behind this requirement is that, since most physical plant placed in service will have some residual value at the time of retirement, the original cost recovered through depreciation should be reduced by that amount. Closely associated with this reasoning is the accounting principle that revenues be matched with costs and the regulatory principle that utility customers who benefit from the consumption of plant pay for the cost of that plant, no more, no less. The application of the latter principle also requires that the estimated cost of removal of plant be recovered over its life.

Similarly, the 1994 edition of *Depreciation Systems* states at page 7:

> The matching principle specifies that all costs incurred to produce a service should be matched against the revenue produced. Estimated future costs of retiring of an asset currently in service must be accrued and allocated as part of the current expenses.

Thus, both sources use mandatory language when describing the traditional approach of accruing "retirement" or "removal" costs over the life of the plant.

Q. DO BOTH OF THESE TEXTS EXPLAIN HOW FUTURE NET SALVAGE IS ESTIMATED?

A. Yes. Both explain that net salvage, expressed as a percentage of original cost of plant in service, is estimated incorporating the same methods of analysis employed in the Company's depreciation studies. That is, both texts support the traditional method of estimating future net salvage.

Q. HOW DOES NARUC EXPLAIN HOW NET SALVAGE SHOULD BE ESTIMATED?

A. NARUC states that "net salvage is expressed as a percentage of plant retired by dividing the dollars of net salvage by the dollars of original cost of plant retired."[4] This is the method of analysis used in the Company's depreciation study and referred to in my testimony as the traditional method.

Q. HOW DO WOLF AND FITCH EXPLAIN THAT NET SALVAGE IS ANALYZED?

A. Wolf and Fitch also explain that net salvage is expressed as a percentage of the original cost of plant retired, noting "the SR [Salvage Ratio] is the salvage

[4] NARUC Manual, p. 18.

divided by the original cost of the retirements and usually is expressed as a percentage."[5]

Q. DO ANY AUTHORITATIVE DEPRECIATION TEXTS SUPPORT MS. MCCULLAR'S APPROACH OF COMPARING NET SALVAGE ACCRUALS TO RECORDED NET SALVAGE COSTS?

A. No. I am not familiar with any. Ms. McCullar did not cite to any authorities that support the actual approach she used.

2. The Traditional Method Meets the Requirements of the Uniform System of Accounts

Q. WHAT IS THE FEDERAL ENERGY REGULATORY COMMISSION ("FERC") UNIFORM SYSTEM OF ACCOUNTS?

A. The Uniform System of Accounts ("USOA") is the standard set of definitions, rules and instructions established by the FERC that provides consistency in accounting for utilities under its jurisdiction. Most jurisdictions, including North Carolina, have adopted the Uniform System of Accounts for the utilities they regulate.

---

[5] Wolf and Fitch, p. 261. Note that, in this context, Wolf and Fitch use the term "salvage" to mean "net salvage." In addition to describing the traditional method, Wolf and Fitch also present more detailed analysis of net salvage by age. The intent of this more detailed analysis is to recognize the impact of age and inflation on the traditional method of net salvage analysis. In the aged net salvage analysis described by Wolf and Fitch, net salvage is first converted to constant dollars. Then, the level of inflation that will occur over the full service life of each asset is calculated (which is often longer than the age of retirements in the historical net salvage data). The result of this more detailed analysis is typically more negative net salvage estimates than would occur from the traditional method.

Q. DOES THE USOA ADDRESS THE ISSUE OF HOW NET SALVAGE COSTS SHOULD BE ACCOUNTED FOR, AND IF SO, HOW?

A. Yes. The USOA requires that net salvage costs be recorded to the accumulated provision for depreciation account and accrued as part of depreciation expense over the course of an asset's service life (i.e., recognized in each period in which the asset provides service) in a systematic and rational manner.

Q. PLEASE DISCUSS IN MORE DETAIL THE USOA'S TREATMENT OF DEPRECIATION.

A. The USOA defines depreciation as follows:

> Depreciation, as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities.[6]

Q. IN THE QUOTE ABOVE, THE USOA REFERS TO DEPRECIATION AS THE "LOSS IN SERVICE VALUE." WHAT IS SERVICE VALUE?

A. Service value, as also defined in the USOA, is "the difference between original cost and net salvage value of gas plant."[7] Thus, the USOA requires that

[6] FERC Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act, definition 12B.
7 FERC Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act, definition 37.

depreciation include net salvage as well as the original cost of the Company's assets.

Q. DOES THE USOA ALSO DEFINE WHAT IT MEANS BY "NET SALVAGE VALUE"?

A. Yes. "'Net salvage value' means the salvage value of property retired less the cost of removal."[8] These costs are recorded to accumulated depreciation at the cost expended (or received as salvage) at the time they occur and are included in depreciation expense over the service lives of the assets.

Q. DOES THE USOA PRESCRIBE A BASIS FOR ACCOUNTING?

A. Yes. The gas USOA includes General Instruction 11, "Accounting to be on accrual basis," which states, "[t]he utility is required to keep its accounts on the accrual basis." Under the accrual basis of accounting, transactions are accounted for when the order is made, the item is delivered, or the service occurs, regardless of when any money for such orders, items, or services is actually received or paid. The accrual basis recognizes economic events without regard to when the related cash transaction occurs. Combined with the use of the term "service value" in the definition of depreciation, the use of accrual accounting means that net salvage costs should be recognized while the asset is providing service – that is, over its service life, rather than when the costs are actually incurred.

[8] *Id*., definition 23.

To further emphasize this point, General Instruction 22 in the electric USOA states:

> Utilities must use a method of depreciation that allocates in a systematic and rational manner the service value of depreciable property over the service life of the property.

While the gas USOA does not have the same language, one can reasonably infer that the service value (including net salvage) for gas plant must also be allocated over the service life of the property. Additionally, the requirement for accrual accounting and the inclusion of net salvage in the service value of an asset similarly require that net salvage costs be recovered over the service life of an asset.

Q. DOES THE TRADITIONAL METHOD SATISFY THESE REQUIREMENTS?

A. Yes. I have demonstrated previously that the traditional method results in the recovery of net salvage costs over the lives of the related assets. The traditional method, therefore, satisfies these requirements of the USOA.

Q. DOES MS. MCCULLAR'S METHOD SATISFY THESE REQUIREMENTS?

A. No. As discussed previously, Ms. McCullar's method is not designed to properly allocate net salvage costs over the service lives of the Company's assets. Instead, her method is based on the level of net salvage costs recently incurred.

3. Ms. McCullar's Method Has Been Rejected in Other Jurisdictions

Q. IS THE TRADITIONAL METHOD WIDELY USED IN THE UTILITY INDUSTRY?

A. Yes. The traditional method is used in the vast majority of regulatory jurisdictions. In contrast, Ms. McCullar's method has been rejected by other jurisdictions.

Q. ARE YOU FAMILIAR WITH ANY STATES THAT HAVE SPECIFICALLY REJECTED THE METHOD FOR NET SALVAGE SIMILAR TO THAT PROPOSED BY MS. MCCULLAR?

A. Yes. There are a number of states that have specifically rejected the approach for net salvage proposed by Ms. McCullar. I will briefly discuss two recent cases in Washington and Massachusetts in which Ms. McCullar's proposals were rejected. Other states that have rejected approaches similar to what Ms. McCullar has proposed include California,[9] Michigan,[10] Georgia,[11] and Missouri.[12]

[9] See California D.07-03-044 in A.05-12-002, pp. 226 and 227.

[10] Michigan Public Service Commission Order, Case No. U-15629, filed September 29, 2009, p. 12.

[11] Georgia Public Service Commission Docket No. 31647, Final Order, filed December 21, 2010.

[12] Missouri Case No. GR-99-315, Third Report and Order issued January 11, 2005, p. 7-16.

Q. PLEASE DESCRIBE THE RECENT CASE IN WASHINGTON IN WHICH MS. MCCULLAR'S NET SALVAGE METHOD WAS REJECTED.

A. On behalf of the Washington Public Counsel, Ms. McCullar proposed net salvage estimates based on a similar net salvage method in a case for Puget Sound Energy ("PSE"). While other parties in that case reached a settlement agreement that adopted most of the recommendations in PSE's depreciation study, the Washington Public Counsel did not agree to the settlement and continued to argue for Ms. McCullar's inappropriate net salvage method. The Washington Commission rejected Ms. McCullar's proposed method, stating:

> 164. Public Counsel's proposed alternative to the Settlement Stipulation's treatment of net salvage of mass assets used in natural gas operations appears to be based on testimony by Ms. McCullar that we find to be vague in its methodology, not supported by authoritative accounting literature, and supported by unwarranted assumptions. Mr. Spanos' estimates of net salvage for natural gas mass assets, in contrast, does not suffer from these deficiencies.
>
> 165. In addition, Ms. McCullar's comparison of net salvage accruals to net salvage expenditures PSE incurred during recent years would effectively recover net salvage as an operating expense, not a depreciation expense. We do not accept this result.
>
> 166. Thus, we reject Public Counsel's alternative viewpoint and approve the Settlement Stipulation with respect to net salvage of mass assets that support PSE's natural gas operations.[13]

---

[13] See page 60 of the Final Order of the Washington Utilities and Transportation Commission in Dockets UE-170033 and UE-170034, issued on December 5, 2017.

Q. PLEASE DESCRIBE THE CASE IN MASSACHUSETTS IN WHICH MS. MCCULLAR'S PROPOSED METHOD WAS REJECTED.

A. Ms. McCullar's firm was involved in a recent case for two Eversource subsidiaries (Massachusetts Docket D.P.U 17-05-F). In that case, Eversource's proposed net salvage estimates were based on the traditional method I have used in the instant case. Ms. McCullar's firm proposed to reduce Eversource's proposed net salvage estimates based on the same approach that Ms. McCullar uses in the instant case.

Upon reconsideration, the Massachusetts Department of Public Utilities ("DPU") rejected the proposal of Ms. McCullar's firm and adopted the company's net salvage proposals. First, the DPU held that:

> [w]e conclude that the Eversource's method of deriving net salvage values was appropriate and, in this instance, should have been accepted.[14]

Ms. McCullar has criticized the traditional method of net salvage in the instant case for incorporating some degree of future inflation and cited to NARUC and Wolf and Fitch in support of her arguments. The Massachusetts DPU disagreed. First, addressing the textbook Wolf and Fitch, the DPU stated:

> [i]t is clear that the final salvage ratios developed using the method described in Depreciation Systems include inflation.[15]

The DPU also stated that:

---

[14] Massachusetts Docket No. D.P.U. 17-05-F, Order on Eversource's Motion for Reconsideration and Motion for Leave to File a Response, dated May 11, 2018, page 13.

[15] Massachusetts Docket No. D.P.U. 17-05-F, Order on Eversource's Motion for Reconsideration and Motion for Leave to File a Response, dated May 11, 2018, pages 16-17.

> Given that the method set forth in Depreciation Systems and the one prescribed by NARUC both recognize an inflation component, the Department no longer is persuaded that Eversource's failure to discount its salvage values for the time value of money resulted in proposed net salvage factors that overstate the Companies' salvage costs and produce excessive depreciation accrual rates. Rather, we find that for the 14 subject accounts, Eversource's proposed net salvage factors appropriately recognize the full service value of the assets in these accounts. While it is true that Eversource's net salvage factors result in higher depreciation rates than those proposed by the Attorney General, we find that the rates, which were calculated according to an acceptable method, are appropriate to ensure that current customers who receive service from those particular assets pay for an appropriate share of the costs for retiring those assets. Therefore, the proposed net salvage factors should have been approved in D.P.U. 17-05.[16]

The DPU affirmed that Eversource's use of the traditional method was consistent with NARUC:

> Based on a review of Eversource's depreciation studies, the Department finds that Eversource's salvage analysis is consistent with the analysis prescribed by NARUC.[17]

Finally, the DPU also concluded that Ms. McCullar's method was not appropriate.

> [w]e conclude that other than demonstrating that her alternative represents a gradual decrease from the Companies' proposed accruals, the Attorney General offered no persuasive explanation why net salvage accruals that are 2.2 times larger than a recent average annual net salvage expense are more

---

[16] Massachusetts Docket No. D.P.U. 17-05-F, Order on Eversource's Motion for Reconsideration and Motion for Leave to File a Response, dated May 11, 2018, pages 16-17.

[17] Massachusetts Docket No. D.P.U. 17-05-F, Order on Eversource's Motion for Reconsideration and Motion for Leave to File a Response, dated May 11, 2018, page 16.

> appropriate than the Companies' proposal or appropriate on their own merit.[18]

The DPU concluded by explaining that Eversource's use of the traditional method was a recognized and accepted approach, that Ms. McCullar's method was not reliable, and that Eversource's depreciation rates were appropriate. Specifically, the DPU stated:

> While we recognize that, in contrast to the selection of average service lives and dispersion curves, the selection of salvage values is more subjective, the Department is not prepared to deviate from a recognized and accepted approach to deriving salvage ratios in the absence of an appropriately supported alternative. In this case, upon reconsideration, we are not persuaded that the Attorney General's alternative approach is sufficiently reliable to warrant a departure from the approach used by Eversource. Moreover, as noted above, we find that the overall depreciation rates proposed by Eversource are appropriate and not excessive.[19]

4. Ms. McCullar's net salvage method has not been accepted in North Carolina

Q. HAS THE NORTH CAROLINA UTILITIES COMMISSION ("COMMISSION") RULED ON THE APPROPRIATE METHOD OF RECOVERING NET SALVAGE?

A. Yes. In recent cases for Duke Energy Progress in Docket No. E-2, Sub 1219[20] and Duke Energy Carolinas in Docket No. E-7, Sub 1214[21], the Commission

---

[18] Massachusetts Docket No. D.P.U. 17-05-F, Order on Eversource's Motion for Reconsideration and Motion for Leave to File a Response, dated May 11, 2018, page 17.
[19] Massachusetts Docket No. D.P.U. 17-05-F, Order on Eversource's Motion for Reconsideration and Motion for Leave to File a Response, dated May 11, 2018, page 18.
[20] State of North Carolina Utilities Commission Raleigh Docket No. E-2, Sub 1219, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, pages 43-44.
[21] State of North Carolina Utilities Commission Raleigh Docket No. E-7, Sub 1214, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice, pages 37-38.

agreed with the utilization of the traditional method which is the same method that was utilized for all accounts in this case by the Company. In both cases, witness McCullar recommended the same methodology for net salvage that she has recommended in this case for the two distribution main subaccounts.

Q. PLEASE DESCRIBE THE RELATED ISSUES IN THE TWO DUKE ENERGY PROCEEDINGS.

A. In the two Duke Energy cases related to mass property net salvage, I represented Duke Energy Progress and Duke Energy Carolinas and provided a depreciation study that utilized the traditional net salvage method for all property accounts consistent with the standards of recovery by all authoritative texts as well as FERC and this Commission. In each of the Duke Energy proceedings Ms. McCullar selectively recommended an alternative method of net salvage for a couple of accounts, which has not been recognized by authoritative texts as appropriate. Ms. McCullar did not provide any support for why those accounts should be treated differently than the other accounts. Ms. McCullar's only apparent justification was that the level of net salvage accruals were much higher than the net salvage costs of recent years. This has clearly been found to be an inappropriate comparison for developing depreciation rates for the future.

Q. HAS MS. MCCULLAR PRESENTED THE SAME ARGUMENT IN THIS CASE RELATED TO NET SALVAGE METHODOLOGY FOR ONLY A COUPLE ACCOUNTS AS PRESENTED IN THE TWO DUKE ENERGY CASES?

A. Yes.

Q. DID THE COMMISSION ACCEPT MS. MCCULLAR'S ARGUMENT IN THOSE CASES?

A. No. The Commission did not adopt Ms. McCullar's arguments and found in both cases that the future net salvage rates for mass property accounts that I proposed were just and reasonable, appropriate for use, and were adopted.

D. Ms. McCullar's Arguments Against the Traditional Method Do Not Provide a Basis to Deviate from the Industry Standard Method for Estimating Net Salvage

Q. WHAT ARGUMENTS DOES MS. MCCULLAR MAKE WITH REGARD TO THE TRADITIONAL NET SALVAGE METHOD YOU HAVE USED?

A. Ms. McCullar's primary argument against the use of the traditional net salvage method relates to the implication that there is future inflation in historical net salvage ratios because historical net salvage and retirements are at different price levels. I note that Ms. McCullar does not provide any reasoning or justification why this would be problematic. While she cites to both the NARUC Manual and Wolf and Fitch, as I mentioned previously, neither text supports her method.

Q. PLEASE ADDRESS THE ARGUMENT MADE BY MS. MCCULLAR REGARDING THE DIFFERENCE IN PRICE LEVELS IN THE CALCULATION OF HISTORICAL NET SALVAGE RATIOS.

A. Ms. McCullar criticizes the traditional method because historical net salvage is expressed at current price levels (meaning the price level when the net salvage is recorded) whereas retirements are recorded at original cost. There are several responses to this criticism. The first is that the Company's current plant balances, to which net salvage ratios are applied, are expressed at original cost. That is, the assets in service are not brand new and many are decades old. Further, these assets will not all be retired today but instead most will be retired in the future. For these reasons, expressing historical net salvage as a percentage of historical retirements makes sense and is appropriate. Not doing so would understate future net salvage.

The second response is that, as discussed in detail in Section II.C, authoritative depreciation textbooks and most regulatory commissions support the use of the traditional method. There is a longstanding history of using the traditional method and most regulatory commissions have not been convinced by the types of arguments set forth by Ms. McCullar.

The third response is that, when one analyzes the age of historical retirements in the net salvage analysis and compares this to the age at which assets currently in service will be retired (i.e., the average service life or the probable life), the time period between installation and retirement in the historical data is typically shorter than will occur for assets in service. Thus, the traditional method of net salvage typically results in conservative estimates of net salvage, at least with regard to any changes in price levels that will occur.

As a final response, Ms. McCullar has not actually attempted to propose a method of estimating or recovering future net salvage that would adjust future net salvage rates for inflation. It may be possible to construct a methodology that would do so, although such a method would have to recognize the age of retirements in the historical net salvage analysis and would be very complex. Ms. McCullar has not proposed such a method. Instead, the only actual analysis she provides is comparing the net salvage proposals to the costs the Company has incurred in recent years. This methodology is not a reasonable basis to estimate future net salvage, much less attempt to adjust future net salvage for inflation.

Q. IN RESPONSE TO A QUESTION OF WHETHER THERE IS “ANY CONCERN REGARDING THE HISTORIC NET SALVAGE RATIOS CALCULATED IN THE DEPRECIATION STUDY,” MS. MCCULLAR CITES WOLF AND FITCH AND NARUC. DO THESE TEXTS SUPPORT THAT THERE IS A “CONCERN” WITH THE TRADITIONAL METHOD?

A. No. These cites do not suggest that there is a “concern” with the traditional method. As discussed in Section II.C.1, both texts support the traditional method and neither support Ms. McCullar’s method. The recognition by both texts of certain aspects of the traditional method does not mean either text considers the difference in price level between net salvage and retirements in historical net salvage ratios to be a concern. Ms. McCullar's testimony should not be misconstrued as support by either of these sources of an alleged "concern" with the traditional method. Rather, both recognize a characteristic of the traditional net salvage analysis, but still support its use.

III. <u>CONCLUSION</u>

Q. DOES THIS CONCLUDE YOUR REBUTTAL TESTIMONY?

A. Yes.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

REBUTTAL TESTIMONY

OF

JOHN D. TAYLOR

OCTOBER 7, 2021

I. INTRODUCTION

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

A. My name is John D. Taylor, and my business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926. I am employed by Atrium Economics, LLC ("Atrium") as a Managing Partner. I am appearing on behalf of Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or the "Company").

Q. HAVE YOU PREVIOUSLY TESTIFIED IN THIS PROCEEDING?

A. Yes, I submitted direct testimony in this proceeding on behalf of PSNC on April 1, 2021, and supplemental direct testimony on behalf of PSNC on August 10, 2021.

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

A. The purpose of my rebuttal testimony is to respond to the direct testimony of other parties in this proceeding relating to the fully-allocated Cost of Service Study ("COSS") that allocates PSNC's gas distribution costs to its rate classes, class revenue increase apportionment, and proposed rate design. Specifically, I will address the following witness testimony and topics:

- Testimony sponsored by Public Staff witness, Jack L. Floyd, relating to the issue of appropriate levels of revenue increases for each rate class, the use of COSS results in setting rates, and suggested improvements in PSNC's COSS methodologies.

- Testimony sponsored by Evergreen Packaging, LLC ("Evergreen") witness, Brian C. Collins, regarding the Company's proposed COSS, revenue increases for each rate class, and rate design for Rate 175 which serves the Company's Firm Large Quantity General Service Transportation customers.
- Testimony sponsored by Carolina Utility Customers Association ("CUCA") witness, Kevin W. O'Donnell, regarding the Company's proposed COSS and revenue increases for each rate class.

Q. WHAT ARE YOUR RECOMMENDATIONS RELATING TO THESE ISSUES?

A. The summary of my conclusions and recommendations is listed below:

- The Commission should adopt the Company's proposed COSS. This study is in alignment with past methods used by PSNC and approved by the Commission.
- The Commission should reject the Public Staff's recommendation to separately include contract customers in the Company's COSS model as rates of return for these customers are most appropriately viewed in the context of the analyses and documentation provided in approval of the terms and conditions of these contracts.
- The Commission should reject the Public Staff's recommendation to require the Company to address the Public Staff's list of conflicting "revenue

assignment principles" and address an undefined "band of reasonableness." These are vague requirements and are duplicative of the requirement for the Company to put on an affirmative case in support of its rate design proposals.

- The Commission should look to move classes closer to parity and reduce subsidies across classes as proposed by Public Staff witness Floyd.
- Issues relating to gradualism and levels of "rate shock" should be reviewed on a relative basis by considering a multiplier of the overall system increase rather than the Public Staff's preference of two percentage points above the system increase.
- The Commission should utilize the Company's proposed revenue increases by class as detailed in my supplemental direct testimony and provided in Table 2 within this rebuttal testimony.
- Regarding rate deign for Rate 175, I support Evergreen's approach of applying the same percentage increase to each block rate as this method results in more revenue recovered in the first block rate than the Company's original proposal. This is not, however, an endorsement of Evergreen's proposed revenue increase for Rate 175.

II. PSNC'S COST OF SERVICE METHODS

Q. WHAT POSITION DID THE PUBLIC STAFF TAKE REGARDING THE METHODS UTILIZED IN THE COMPANY'S COST OF SERVICE STUDY?

A. Public Staff witness, Jack L. Floyd, states that the Public Staff does "not oppose the use of the filed COSS in this proceeding."[1] He also states that due to constraints on time, he was unable to thoroughly review the Company's COSS. He intends to conduct a deeper investigation into the COSS and work with the Company to achieve a fuller understanding of the COSS prior to the Company's next general rate case filing. One area Mr. Floyd highlights as a concern is his difficulty in discerning the differences in "cost causation associated with contract customers, and large general service customers who are 'sales' and 'transportation' customers."[2]

Q. WHAT IS YOUR RESPONSE TO WITNESS FLOYD'S CONCERN REGARDING CONTRACT CUSTOMERS?

A. Mr. Floyd would prefer a cost of service study that separately identifies the contract revenues, expenses, and rate base to gain an understanding of the rate of return for these contract customers; however, this is entirely unnecessary. Mr. Floyd's desire to understand the rate of return for contract customers can be satisfied with documentation utilized by the Commission in the approval of these contracts and does not require a separate "class" for contract customers

---

[1] Public Staff Direct Testimony of Jack Floyd dated September 23, 2021, at page 10.
[2] Public Staff Direct Testimony of Jack Floyd dated September 23, 2021, at page 12.

within the Company's COSS model. PSNC performs a project-specific analysis of the incremental costs required to provide service to any new contract customer and then analyzes the contributions needed from the customer to fully compensate PSNC for the costs of serving that specific customer over the life of the contract. This analysis and the applicable rates, charges, and terms and conditions of each contract are individually reviewed and approved by the Commission. In short, these Commission approved contract rates are set to ensure that the incremental costs of service are fully covered by the revenues and that any additional revenues result in a reduction to all ratepayers. The Company's COSS treats these revenues in an appropriate manner by crediting these contract revenues to all classes resulting in a reduction of the revenue requirement for PSNC's other customer classes.

Q. PLEASE ADDRESS MR. FLOYD'S CONCERN THAT IT IS DIFFICULT TO DISCERN THE IMPACTS IN COST CAUSATION ASSOCIATED WITH LARGE GENERAL SERVICE CUSTOMERS WHO ARE "SALES" AND "TRANSPORTATION" CUSTOMERS?

A. Mr. Floyd recommends that future COSS distinguish between sales and transportation customers for each of the large general service customer classes. A COSS for sales service and transportation service separately is not necessary as the cost of service being allocated to the classes is associated with the provision of distribution service, not the procurement of gas. The customers on Rate 175 and Rate 180 are transportation customers who qualify for service on Rate 145 and Rate 150, respectively. These transportation customers receive the same quality of service from the Company as customers on their counterpart rates but choose to procure gas supply from a third party. Thus, the distinguishing characteristic is their procurement of gas, not the cost to serve or the quality of service. Further, there is no ability to target different increases of distribution rates for sales and transportation customers as these customers can migrate between the two groups and any rate differential would influence customer choice. As such, I take issue with Public Staff witness Floyd's recommendation and recommend future PSNC COSS continue to model sales and transportation customers together.

Q. WHAT POSITION DID EVERGREEN AND CUCA TAKE WITH REGARD TO THE METHODS UTILIZED IN THE COSS?

A. Both Evergreen witness Collins and CUCA witness O'Donnell criticized PSNC's COSS model for utilizing the Peak and Average allocation method for distribution mains. The issue at hand, which from my review is not a newly debated issue in front of this Commission, is the appropriate method for allocating demand-related costs of distribution mains to each customer class. Both Evergreen witness Collins and CUCA witness O'Donnell propose to utilize peak demand to allocate these costs rather than the proposed Peak and Average methodology. While different methodologies across the industry are used to allocate demand costs, there are three basic methodologies that form the foundation for the allocation process: Coincident Peak Demand Allocations, Average and Excess Demand Allocations, and Non-Coincident Demand Allocations.

Q. PLEASE DESCRIBE THOSE THREE METHODOLOGIES IN GREATER DETAIL.

A. The concept of Coincident Peak Demand Allocation, also referred to as the "design day" method, is premised on the notion that investment in capacity is determined by the peak demand(s) of the utility. Under this methodology, demand-related costs are allocated to each customer class in proportion to the demand of that customer class coincident with the system peak. The Coincident Peak Demand Allocation process might focus on a single system peak, such as the highest daily demand occurring during the test period. Alternatively, it might include the average of consecutive cold days that surround the system peak, system peak days occurring over a period of several years, or it could be the expected contribution to the system peak under weather conditions for which the system was designed to serve, commonly referred to as a "design day."

The Average and Excess Demand Allocation methodology, also referred to as the "used and unused capacity" method, allocates demand-related costs to the classes of service on the basis of system and class load factor characteristics. A simplified version of this methodology is the Peak and Average methodology. This cost methodology often gives equivalent weight to peak demands and average demands. As is the case with the Average and Excess method, it has the effect of allocating a portion of the utility's capacity costs on a commodity-related basis.

The Non-Coincident Demand Allocation methodology recognizes that certain facilities, in particular distribution facilities, are designed to serve local peaks, which may or may not be coincident with the system peak loads. This is often used for the allocation of demand-related costs associated with local electric distribution facilities. Using this methodology, demand costs are allocated based on maximum demand of each rate class, irrespective of the time of the system peak.

Q. WHAT ANALYSIS DID YOU CONDUCT WHEN SELECTING THE PROPOSED METHOD FOR ALLOCATING THE DEMAND-RELATED COSTS OF DISTRIBUTION MAINS?

A. When selecting methods to be utilized in a class cost of service study for purposes of a base rate filing, I often review the history of different methodological approaches, the duration of the methods used in the past, methods employed by other utilities in the jurisdiction, and the support of the Commission for different methodological approaches. In preparing PSNC's COSS, I reviewed the methods utilized by PSNC in its last base rate case proceeding, the methods used by Piedmont Natural Gas Company in past proceedings and in the current Piedmont proceeding, and past Commission orders citing a preference for the use of the Peak and Average methodology. It was apparent that the Peak and Average methodology has been tried and tested by this Commission and has previously been found to be the most reasonable:

> The Peak and Average allocation methodology used by PSNC and the Public Staff recognizes that PSNC's facilities provide service on an annual as well as a peak basis. The Commission concludes that it is

> more appropriate to use the Peak and Average methodology to allocate costs than it is to use the Peak Responsibility or Imputed Load Factor methodologies proposed by CUCA.[3]

As such, the decision was made, in consultation with PSNC, to continue to utilize the Peak and Average method for allocating the demand portion of distribution mains.

Q. WHAT IS THE NATURE OF THE REPORT ISSUED BY YOUR FIRM, ATRIUM ECONOMICS, FOR CENTRA GAS MANITOBA, INC. THAT EVERGREEN WITNESS COLLINS REFERENCES?

A. Evergreen witness Collins references a recently issued report authored by Atrium Economics, for which I am a managing partner, that recommended the use of the design day method to allocate the demand related distribution main costs. Historically, Centra Gas Manitoba, Inc. ("Centra Gas") utilized the Peak and Average methodology for the allocation of distribution mains and was ordered by the Public Utilities Board of Manitoba ("PUB") to retain an outside expert to review their cost of service methodologies and provide an opinion on the methods utilized. As Evergreen witness Collins correctly summarizes and can be seen in the report, fully attached to his testimony, Atrium Economics' recommendation to Centra Gas was to replace the use of the Peak and Average allocation method with a Coincident Peak Demand Allocation method.

[3] *Order Granting Partial Rate Increase,* Docket No. G-5, Sub 386 (Oct. 30, 1998).

Q. PLEASE SUMMARIZE THE CIRCUMSTANCES UNDER WHICH ATRIUM ECONOMICS WAS RETAINED BY MANITOBA HYDRO TO CONDUCT THE REVIEW THAT WITNESS COLLINS CITES AS SUPPORT FOR THE DESIGN DAY PEAK ALLOCATION METHOD FOR DISTRIBUTION MAINS.

A. PUB Order No. 152/[4] required Centra Gas to retain an outside expert to review their entire cost of service methodologies and provide an opinion on the methods utilized. Several intervenor expert witnesses (including Evergreen witness Collins, who supported Centra Gas's Special Contract customer) in that general rate application proceeding filed evidence identifying aspects of Centra Gas's cost of service study that, in the view of those witnesses, required review and ultimately a different methodological approach.

One issue of particular focus was the allocation of transmission costs. In Centra Gas's cost of service study, transmission costs relate to the costs of constructing and operating Centra Gas's high pressure transmission system, including the costs of steel pipelines and pressure regulating stations, as well as unaccounted for gas. The Large General Service, High Volume Firm, Special Contract[5], and Main Line customer classes were all proposed to receive an increase in their allocated portion of non-gas costs. For the Special Contract customer class in particular, the share of non-gas costs had increased due to an increase in the proportion of rate base that is transmission-related as opposed to

---

[4] Final Order with Respect to Centra Gas Manitoba Inc.'s 2019/20 General Rate Application, October 11, 2019.

[5] The Special Contract class was a client of Evergreen witness Collins.

distribution-related. As these customers do not use Centra's distribution system, these customers are allocated proportionately more costs when there is a greater increase in transmission-related costs than distribution-related costs.

Q. HOW SHOULD THIS REPORT BE USED IN DETERMINING THE APPROPRIATE METHOD OF ALLOCATING MAINS FOR PSNC?

A. It should not be relied upon as there is a fundamental distinction between the review conducted by Atrium Economics for Centra Gas and the current proceeding for which I am sponsoring testimony. The PUB directed Centra Gas to retain an outside consultant to review Centra Gas's cost of service methodology, which provided a distinct opportunity to present and discuss the pros and cons of different methodological approaches outside of a base rate case proceeding in which the PUB, Centra Gas, and outside stakeholders could put forth dedicated effort reviewing issues relating specifically to cost of service methods. The current general rate proceeding involves a large set of required analysis of issues, detailed information, significant review by all parties, and a multitude of issues that are unique to PSNC. It is a difficult setting to evaluate topics that often impact multiple utilities. Therefore, Commissions often utilize generic proceedings to review broader methodological issues and regulatory approaches that impact multiple utilities within their jurisdiction.

Q. WHAT ARE THE IMPLICATIONS ON PSNC'S COSS RESULTS FROM REPLACING THE PEAK AND AVERAGE WITH THE COINCIDENT PEAK DEMAND ALLOCATION METHODOLOGY?

A. As indicated in the direct testimony of Evergreen witness Collins, a COSS was developed and provided to Evergreen that replaced the use of the Peak and Average Allocation method with a Coincident Peak Demand Allocation method for the demand component of distribution mains. Table 1 below compares PSNC's proposed COSS with this requested alternative provided to Evergreen.

Table 1 – Total Revenue Deficiency (Surplus) by Class – Allocation of Mains

Rate Class	Distribution Mains Allocated on Peak and Average	Distribution Mains Allocated on Design Day	Difference
Residential Service	$ 26,545,420	$ 44,071,131	$ 17,525,711
Small General Service	$ 4,753,404	$ 7,335,816	$ 2,582,412
Medium General Service	$ (1,319,493)	$ (1,393,247)	$ (73,754)
Large Quantity General Service	$ 15,596,017	$ 1,517,992	$(14,078,025)
Large Quantity Interruptible Service	$ 7,570,129	$ 1,613,785	$ (5,956,344)
Total Company	$ 53,145,478	$ 53,145,478	$ (0)

As can be seen from this table, the result of moving from a Peak and Average methodology to a design day is to shift cost responsibility from the higher load factor classes Large Quantity General Service and Large Quantity Interruptible Service to the lower load factor classes Residential Service and Small General Service. This is to be expected given the arithmetic of the two alternative allocation methodologies (i.e., the peak and average allocation is weighted 50% on annual throughput and 50% on design day, whereas the design day allocation method does not incorporate annual throughput).

Q. WHAT CONCLUSIONS SHOULD BE MADE RELATING TO THE ALLOCATION OF DISTRIBUTION MAINS?

A. The comparison of these two methods illustrates that movement from the Peak and Average to the design day, to use the words of Evergreen witness Collins "make[s] any corrective distribution of the requested increase even more difficult to manage in this case."[6] As stated by CUCA witness O'Donnell, "I used the SWPA [peak and average] ACOSS in the development of my recommended rate design. The reason is that use of the Peak Day ACOSS would not have altered my recommended rate design in any meaningful way."[7] In short, correcting the rate of return disparities across the classes under either method may very well be limited by considerations of gradualism and rate shock, which I will now discuss.

III. REVENUE INCREASES FOR EACH RATE CLASS

Q. WHAT IS THE PUBLIC STAFF'S POSITION RELATING TO THE ASSIGNMENT OF THE REVENUE INCREASE TO EACH RATE CLASS?

A. It appears through reviewing Public Staff witness Floyd's direct testimony in this proceeding and the Public Staff's responses to PSNC's data request[8]

---

[6] Evergreen Direct Testimony of Brian Collins dated September 23, 2021, at page 13.

[7] CUCA Direct Testimony of Kevin O'Donnell dated September 23, 2021, at page 102. The testimony references the SWPA ACOSS; however, the Company is not proposing to use the Summer Winter Peak Analysis (SWPA) a term used in the context of electric production facility allocations. The proposed method is a peak and average where the peak is equal to the design day winter peak demand.

[8] Response of the Public Staff to PSNC's Second Data Request – Requests 2-1 through 2-4.

(provided as Taylor Rebuttal Exhibit 1) there are several principles considered by the Public Staff Witness Floyd's testimony lists four goals:[9]

(1) Limit any revenue increase to no more than two percentage points greater than the overall revenue increase.

(2) Maintain a ± 10% "band of reasonableness" for rate of returns relative to the overall jurisdictional rate of return.

(3) Move each customer class toward parity with the overall jurisdictional rate of return.

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

Items three and four are in direct alignment, where a movement towards parity will minimize any existing subsidies across classes. At the extreme, all classes could move 100% to parity and no subsidies would remain; however, this is often not optimal given gradualism and rate shock considerations. Item two indicates that there is an assumed range of reasonableness for rate classes' rate of return, set to ± 10% relative to the overall jurisdictional rate of return. From my experience and the position described in my direct testimony, these are all sensible goals.[10] With respect to item one, limiting any increase to two percentage points greater than the overall revenue increase, I have some misgivings.

[9] These are summarized for brevity. Please see Public Staff Direct Testimony of Jack Floyd dated September 23, 2021, at pages 4-5 for the full text.
[10] See the Direct Testimony of PSNC witness John Taylor dated April 1, 2021, at pages 19-21.

Q. WHAT CONCERNS DO YOU HAVE WITH THE PUBLIC STAFF'S GOAL OF LIMITING ANY INCREASE TO TWO PERCENTAGE POINTS GREATER THAN THE OVERALL REVENUE INCREASE?

A. This goal is arbitrary, has no theoretical support, is in direct conflict with the other stated goals, and its application limits the ability to move classes effectively towards parity over a reasonable time. As an illustrative example, let's suppose a utility's revenue increase is 10% and one class would require a 30% increase to move its rate of return within the band of reasonableness. The adherence to this goal would only allow an increase to this class of 12% (two percentage points greater than the overall revenue increase), less than half of what is required. Let's suppose this utility does not file another rate case for five years and that case shows the total system increase is 6%, thus limiting this class to an 8% increase. The subsidy would continue to exist for years, possibly decades, and the question would need to be posed: How should concerns relating to "rate shock"[11] be balanced with concerns over subsidies across classes and their duration? The best approach to deal with this conflict is to consider the relative increases across the classes rather than an absolute difference of two percentage points between the overall system increase and any one class. For example, if the system experiences an increase of 5%, is an increase in excess of 7% "rate shock"? Or, if a system experiences an increase

[11] I use the Public Staff's term "rate shock" in the context of Mr. Floyd's testimony relating to the rate class increase above the system average increase. However, the term is often used in the context of reviewing the overall impact on customers' bills rather than simply a percentage increase on class margin. The concept of gradualism is invoked as well, where large rate increases for individual classes of customers are tempered in an attempt to avoid "rate shock."

of 20%, is an increase greater than 22% "rate shock"? The approach that should be used to judge rate shock or the use of gradualism to avoid rate shock is the relative difference between the system's increase and the increase for any one class of customers. It is a determination of which classes should bear the increase in relation to other classes, a determination in which only a relative attribute can be informative.

Q. WHAT RELATIVE ATTRIBUTE OF RATE INCREASES CAN BE INFORMATIVE WHEN JUDGING THE APPROPRIATENESS OF REVENUE INCREASES FOR EACH CLASS?

A. Examining class rate increases as a multiplier of the total system increase can ensure the concept of gradualism is appropriately taken into account. The relevant questions are how much should rates change in order to move classes towards parity and what is the balance between any individual class's increase and the overall system increase. Using a multiplier of the overall system return is a common method of limiting increases to any one class in relation to the overall system increase. The Company's proposal presented in my direct testimony applies this metric by limiting any individual classes increase as two times the overall system increase.

Q. WHAT IS THE PUBLIC STAFF'S RECOMMENDATION FOR REVENUE INCREASE BY CLASS?

A. The Public Staff presents no revenue increase by class within Mr. Floyd's direct testimony. He indicated that the Public Staff intends to file supplemental testimony on its recommended jurisdictional revenue requirement and assignment of their proposed revenue change to each rate class.

Q. WHAT OTHER RECOMMENDATIONS ARE MADE BY THE PUBLIC STAFF RELATING TO SETTING REVENUE INCREASE BY CLASS?

A. Public Staff witness Floyd states:

> Therefore, the Public Staff recommends that the Commission require the Company to address each of these revenue assignment principles in its next general rate case filing. The Commission should also require the Company to explain why any class ROR under proposed rates that falls outside of a band of reasonableness should be allowed going forward.[12]

In short, these issues have been addressed in this proceeding; that is, my direct testimony and rebuttal testimony demonstrate that there are various goals and principles relating to setting revenue increases for each rate class; reviewing increases on a relative attribute basis is most appropriate; and the Company's proposed revenue increases by class presented in direct testimony and supplemental testimony balance these various goals and principles in an effective manner. Each general rate case filing presented to this Commission requires PSNC to make an affirmative case of why its proposals are reasonable and should be approved. Witness Floyd's proposal to require the Company to address the Public Staff's list of conflicting "revenue assignment principles," notably requiring the Company to justify different approaches for electric and natural gas utilities and requiring justification of rate classes outside an

[12] Public Staff Direct Testimony of Jack Floyd dated September 23, 2021, at pages 12.

undefined "band of reasonableness," should be rejected. This proposal creates a vague requirement that is duplicative of the Company's obligation to put on an affirmative case in support of its rate design proposals.

Q. WHAT IS CUCA'S PROPOSED REVENUE INCREASE BY CLASS AND THE RATIONALE FOR ITS PROPOSAL?

A. CUCA witness O'Donnell proposes to limit any rate increase or decrease to no more than 10% of current class revenues. The support for this approach is that Mr. O'Donnell "attempted to balance the interest of all customer classes without allowing any one particular class to sustain excessive rate hikes while other classes enjoyed significant rate cuts."[13] Mr. O'Donnell also states, "that Mr. Taylor paid no attention to rate shock that, if adopted by this Commission will run manufacturers, their jobs, and their tax base out of North Carolina."[14]

Q. DID YOU CONSIDER ISSUES OF RATE SHOCK AND GRADUALISM WHEN SETTING REVENUE INCREASE FOR EACH RATE CLASS?

A. Yes. In addition to considering gradualism and rate shock, I also considered goals of moving classes closer to parity and reducing subsidies across classes, which are in alignment with the Public Staff's goals described above and, possibly Mr. O'Donnell's statement that "CUCA and I also want to do what is right."[15] My limitation on class revenue increases was two times the overall system increase, and while some may disagree with the two times limitation, this is an appropriate measure of the relative increase to each class which, as

[13] CUCA Direct Testimony of Kevin O'Donnell dated September 23, 2021, at page 102.
[14] CUCA Direct Testimony of Kevin O'Donnell dated September 23, 2021, at page 102.
[15] CUCA Direct Testimony of Kevin O'Donnell dated September 23, 2021, at page 102.

detailed above, should be used to judge limits to revenue increases for any one class.

Q. WHAT SUPPORT DID CUCA PROVIDE TO SUPPORT MR. O'DONNELL'S STATEMENT THAT THE COMPANY'S PROPOSAL WILL BE DETRIMENTAL TO MANUFACTURERS IN NORTH CAROLINA?

A. CUCA provided no such support in Mr. O'Donnell's direct testimony. In data request responses (provided as Taylor Rebuttal Exhibit 2), CUCA acknowledged that witness O'Donnell had completed no financial analysis, reviewed no tax-base analysis, and performed no bill impact analyses. The responses stated that Mr. O'Donnell relied solely on his numerous years as an energy analyst in North Carolina.[16]

Q. WHAT IS EVERGREEN'S PROPOSED REVENUE INCREASE BY CLASS AND RATIONALE FOR ITS PROPOSAL?

A. Witness Collins states, "No class should receive an increase more than a maximum 150% of the average increase as an upper limit."[17] This is instructive as witness Collins uses the same relative attribute of individual class increases as a ratio of total system increase to set limits to increases by class, which is the same relative attribute I used in direct testimony and advocate for in this rebuttal testimony. The difference is that, while I have used a two times ratio, witness Collins suggests a 1.5 times ratio. Ultimately witness Collins's proposal is as

[16] CUCA Response to Company Requests 2-1 and 2-2

[17] Evergreen Direct Testimony of Brian Collins dated September 23, 2021, at page 3.

follows, "Classes close to cost of service received an approximate average increase; classes above cost of service receive approximately 50% of the average increase."[18] The resulting increases by class are different from the Company's proposal due to Evergreen using the peak day methodology for allocating mains compared to the Company's proposed method using Peak and Average.

Q. WHAT IS YOUR RESPONSE TO MR. COLLINS'S PROPOSAL?

A. Witness Collins's recommendation is based on an allocation method of distribution mains that has been explicitly rejected by this Commission in past proceedings, as discussed above. As a result, Evergreen's proposed rate increase by class should not be relied upon in this proceeding.

Q. WHAT REVENUE INCREASE BY CLASS SHOULD THE COMMISSION USE TO SET RATES IN THIS PROCEEDING?

A. The Commission should approve the Company's proposal presented in my supplemental testimony. Table 2 below provides each party's proposal on revenue increases by class as a percentage increase of distribution margin.

[18] Evergreen Direct Testimony of Brian Collins dated September 23, 2021, at page 14.

Table 2 – Proposed Percentage Increase in Distribution Margin by Party[19]

	PSNC Supplemental		CUCA		Evergreen	
Rate Class	Percent Change in Dist Margin	Increase Relative to System Increase	Percent Change in Dist Margin	Increase Relative to System Increase	Percent Change in Dist Margin	Increase Relative to System Increase
Residential Service	13.48%	0.87	10.76%	0.96	16.53%	1.00
Small General Service	17.45%	1.12	12.74%	1.14	21.41%	1.29
Medium General Service	9.24%	0.60	6.50%	0.58	11.34%	0.68
Large Quantity General Service	30.21%	1.95	13.88%	1.24	9.27%	0.56
Large Quantity Interruptible Service	27.18%	1.75	12.11%	1.08	16.67%	1.00
Total Company	15.51%		11.20%		16.60%	

The second column for each party provides the increase by class relative to the system increase. For Evergreen and CUCA to limit the increases to Large Quantity General Service and Large Quantity Interruptible Service their proposals require a higher relative increase for the Residential Service and Small General Service classes. Under Evergreen's proposal this equates to an additional $6.2 million increase to those classes resulting in a 15% increase above the Company's proposal.[20]

IV. RATE DESIGN

Q. WHAT ISSUES RELATING TO RATE COMPONENTS WERE RAISED BY OTHER PARTIES IN THEIR DIRECT TESTIMONY?

A. As described in my direct testimony, PSNC is proposing no increases to the basic facilities charge or other miscellaneous fees. The proposed revenue

---

[19] PSNC Updated – See the Supplemental Testimony of PSNC witness Taylor at page 7. CUCA – Derived from the workpapers provided in response to PSNC Data Request 2-6. Evergreen – Evergreen Exhibit BCC-3 which is based on the overall increase presented in PSNC's direct testimony and not the supplemental testimony, which reduced the revenue increase from 16.60% to 15.51%.

[20] The Company's proposal as presented in Schedule 3 - Revenue Apportionment (See G-1 Item 3 page 12 of 236) was $42,362,488 for these two classes, compared to Evergreen's Exhibit BCC-3 which contains a proposed increase of $48,565,115.

increases will be fully recovered through the volumetric charges. No party questioned or commented on this general principle, just on the allocation of the overall increase to each of the rate classes discussed in the previous section of this rebuttal testimony. The only party to discuss issues relating to rate components was Evergreen.

Q. WHAT CONCERNS WERE RAISED BY EVERGREEN WITH REGARD TO PSNC'S PROPOSED RATE COMPONENTS?

A. Mr. Collins solely focuses on the volumetric block rates for Rate 175 (Large Quantity General Service-Transportation Customers) and proposes an across-the-board increase to each block rate of 9.9%, which results in a total class increase of 9.3%.[21] This contrasts with the Company's proposal, which maintains the volumetric rate delta across the block rates (i.e., currently the last block is 9 cents below the first block rate and the proposed last block was targeted for the same 9 cent differential).

Q. WHAT ARE THE RESULTING DIFFERENCES BETWEEN THESE TWO APPROACHES?

A. Table 3 below provides a comparison of PSNC's approach and Evergreen's approach. The PSNC's Rate 175 Approach column provides the proposal presented in my direct testimony based on maintaining the volumetric rate delta across the block rates. The Evergreen Rate 175 Approach column provides the results of applying Evergreen's approach of an equal percentage increase to

[21] Evergreen Direct Testimony of Brian Collins dated September 23, 2021, at page 15.

each block rate based on the overall increase for this class proposed by PSNC. This allows for an appropriate comparison of how these two approaches' results may differ. As can be seen from Table 3 they are materially the same, both resulting in 5% of the volumetric revenues and a rate of 7.8 cents for PSNC's approach and 7.1 cents for Evergreen's approach.

Table 3 – Comparison of Approaches for Designing Rate 175 Volumetric Rate

		PSNC's Rate 175 Approach			Evergreen Rate 175 Approach		
Rate 175 Volumetric Block	Therms	Rate	Revenue	% of Volumetric Revenue	Rate	Revenue	% of Volumetric Revenue
First 15,000 Therms	43,775,946	$ 0.17900	$7,835,676	30%	$ 0.20293	$8,883,576	34%
Next 15,000 Therms	23,662,709	$ 0.15813	$3,741,666	14%	$ 0.17278	$4,088,559	16%
Next 15,000 Therms	16,090,255	$ 0.13948	$2,244,188	9%	$ 0.14583	$2,346,510	9%
Next 15,000 Therms	11,864,080	$ 0.11512	$1,365,734	5%	$ 0.11065	$1,312,754	5%
Next 1,000,000 Therms	97,680,420	$ 0.09485	$9,264,501	36%	$ 0.08136	$7,947,565	31%
Over 1,060,000 Therms	17,577,890	$ 0.07837	$1,377,492	5%	$ 0.07113	$1,250,292	5%
Total Therm Sale Rev.	210,651,300		$25,829,256			$25,829,256	

Q. WHAT IS YOUR RECOMMENDATION RELATING TO THE RATE COMPONENTS FOR RATE 175?

A. As previously discussed in this testimony, the overall rate increase for Rate 175 that Mr. Collins is targeting with his rate design is based on the allocation of distribution mains on design day. As such, the starting point for rate design and revenue increases by class proposed by witness Collins is not supported by North Carolina precedent. I agree with witness Collins that, without a demand charge for these larger customer classes, it is important to recover fixed costs in the first block of rates with higher usage blocks having relatively lower charges. As demonstrated in Table 3 above, the results under these two approaches are materially the same; however, Evergreen's approach of applying the same percentage increase to each block rate does result in more revenue recovered in the first block rate. As such, I support the application of the same percentage increase to each block rate as proposed by witness Collins. This is not, however, an endorsement of his targeted revenue increase by class.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, although I reserve the right to supplement further or amend my testimony before or during the Commission's hearing in this proceeding.

BEFORE THE

NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

REBUTTAL TESTIMONY

OF

REGINA J. ELBERT

OCTOBER 7, 2021

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

A. My name is Regina J. Elbert. My business address is 600 Canal Place, Richmond, Virginia 23219. I am employed by Dominion Energy Services, Inc., as Vice President of Human Resources Business Services. In that capacity, I oversee the human resources function for the company, including Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or the "Company").

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND, WORK EXPERIENCE, AND OTHER QUALIFICATIONS.

A. I have a Bachelor of Arts degree in economics and foreign affairs from the University of Virginia and a Juris Doctor degree from Harvard Law School. In 2011, I joined Dominion Energy, Inc. ("Dominion Energy") as senior counsel for employee benefits and was promoted to manager of Executive Compensation in 2014. In 2017, I became managing counsel and in September 2018, was named deputy general counsel. In March 2019, I was promoted to my current position as Vice President of Human Resources Business Services.

Q. HAVE YOU PROVIDED DIRECT TESTIMONY IN THIS PROCEEDING?

A. No.

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

A. The purpose of my rebuttal testimony is to respond to 1) the testimony of Public Staff witness, Mary A. Coleman, regarding her proposal to disallow the total compensation of the top five executives in terms of compensation charged to PSNC; and 2) the testimony of Public Staff witness, Sonja R. Johnson, regarding her proposals to disallow components of both Annual Incentive Plan compensation and Long-Term Incentive Plan compensation for all executive level employees.

EXECUTIVE COMPENSATION

Q. WHAT IS PUBLIC STAFF WITNESS COLEMAN'S BASIS FOR THE TOP FIVE EXECUTIVES' COMPENSATION CHARGED TO PSNC BEING DISALLOWED IN PSNC'S COST-OF-SERVICE?

A. While Public Staff witness Coleman doesn't suggest that these executives' compensation is excessive, she states:

> This recommendation is based on the Public Staff's belief that it is appropriate and reasonable for the shareholders of the very large natural gas and electric utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests, which are not always the same as those of ratepayers.

Q. WHAT IS PUBLIC STAFF WITNESS COLEMAN'S BASIS FOR CHOOSING TO REMOVE 50% OF THE TOP FIVE EXECUTIVES' COMPENSATION CHARGED TO PSNC?

A. Public Staff witness Coleman states:

> Officers have fiduciary duties of care and loyalty to shareholders, but not to customers. Consequently, the Company's executive officers are obligated to direct their efforts not only to minimizing the costs and maximizing the reliability of PSNC's service to customers, but also to maximizing the Company's earnings and the value of its shares. It is reasonable to

> expect that management will serve the shareholders as well as the ratepayers; therefore, a portion of management's compensation and pensions should be borne by the shareholders.

Q. AS A GENERAL MATTER, ARE DOMINION ENERGY'S REGULATED UTILITIES, SUCH AS PSNC, BURDENED WITH 100% OF EXECUTIVE COMPENSATION?

A. No. Under the Dominion Energy Services Agreement approved by this Commission, executive services are allocated across all affiliates within Dominion Energy – both regulated and non-regulated. There is also a portion allocated to the parent company, Dominion Energy, Inc. The parent company's and non-regulated entities' portions represent 22.4% of the total, with the shareholders bearing those costs rather than utility customers.

Q. ARE EXECUTIVE COMPENSATION COSTS ALLOCATED TO PSNC IN THE TEST PERIOD JUST AND REASONABLE EXPENSES?

A. Yes.

Q. ARE EXECUTIVES COMPENSATED IN WAYS THAT FURTHER SHAREHOLDER INTERESTS AT THE EXPENSE OF THE INTERESTS OF OUR CUSTOMERS?

A. No. The Company's market-competitive compensation policies focus all employees, including executives, on providing safe and reliable gas distribution service in a sustainable manner. Officers of the Company are responsible to all our constituents – employees, customers, shareholders, and the communities we serve. In fact, one of the officers selected by Public Staff witness Coleman is the leader in charge of regulation and customer experience – a position most definitely aligned with the interests of PSNC's customers.

ANNUAL INCENTIVE PLAN ("AIP") COMPENSATION

Q. WHAT IS PUBLIC STAFF WITNESS JOHNSON'S BASIS FOR THE ELIMINATION OF COMPONENTS OF AIP COMPENSATION FOR ALL EXECUTIVES?

A. Public Staff witness Johnson eliminates a portion of AIP compensation for all executives on the basis that financial metrics, specifically earnings per share ("EPS") align with shareholder interests, not customers. Witness Johnson states:

> I have adjusted the allowable costs of AIP to exclude the incentive amounts that were based on the earnings metric, which is closely tied to the EPS, since the entire AIP is funded based upon a consolidated EPS. I have removed only the amounts related to all executive-level employees because these goals align with the shareholders' interests.

Q. HOW IS THE COMPANY'S AIP INCENTIVE COMPENSATION STRUCTURED?

A. The AIP focuses the workforce on goals that align with corporate values and drive toward safe and efficient operations, reliable service for our customers, and the achievement of financial results. The objective is to strive for targeted performance levels in the areas of safety, diversity and inclusion, and environmental benefits, financial performance, and other operating and stewardship targeted performance, by emphasizing teamwork on common goals.

Q. WHAT ROLE DO FINANCIAL METRICS PLAY IN AIP COMPENSATION?

A. The financial targets and the stewardship goals exist in a mutually dependent way at all levels. Financial performance metrics instill a culture of cost-consciousness to serve PSNC's customers efficiently and safely while striving towards strong operating performance targets. Financial stewardship is completely aligned with our customers' interests, ensuring that all of our operational and customer service goals are achieved within a culture of economic efficiency that helps to maintain reasonable costs for our customers.

Q. HOW ARE FINANCIAL GOALS SET?

A. Financial goals are set for the Company at the beginning of each year through the budgeting process. When those goals are met, costs are controlled, and upward pressure on rates is reduced. The resulting culture of economic efficiency and cost control is built up year by year and directly benefits customers through a more efficient utility and lower rates.

Q. WHEN PUBLIC STAFF WITNESS JOHNSON REFERENCES "CLOSE TIES TO EPS" IN REASONING THAT SUCH A PORTION OF AIP SHOULD BE DISALLOWED, WHAT ITEMS ARE ACTUALLY UNDER THE CONTROL OF MANAGEMENT WHEN INFLUENCING FINANCIAL METRICS SUCH AS EPS OR NET INCOME?

A. When evaluating the Company's bottom-line, there are items under the control of the Commission such as PSNC's tariff rates and revenues as well as PSNC's depreciation rates. Taxing authorities at the federal and state level control federal and state income tax expense and payroll tax expense. Debt costs are driven by the financial markets. Thus, the primary item under the control of management is operations and maintenance expense. And while shareholders value the diligent management of operations and maintenance expense, that diligence is equally important to customers because it has a direct outcome on the customer bill for gas distribution service. Ultimately, if PSNC can manage its business in a way that allows it to meet financial targets and expectations year by year, a culture of cost control will be created and sustained, and access to capital on reasonable terms will be assured. Again, customers will benefit through lower costs for gas distribution services.

<u>LONG-TERM INCENTIVE PLAN ("LTIP") COMPENSATION</u>

Q. WHAT IS PUBLIC STAFF WITNESS JOHNSON'S BASIS FOR THE ELIMINATION OF LTIP COMPENSATION FOR ALL EXECUTIVES?

A. Public Staff witness Johnson eliminates a portion of LTIP compensation for all executives on the basis that performance shares tied to return on invested capital ("ROIC") and total shareholder return ("TSR") align with shareholder interests, not customers. Witness Johnson states:

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

Q. WHY IS LTIP COMPENSATION APPROPRIATE FOR RECOVERY IN PSNC'S COST-OF-SERVICE?

A. Long-term incentive plans are recognized throughout the industry as an important way to attract, retain, and motivate key talent. LTIP is a standard executive benefit in the utility industry and in industries across the economy. It forms an important part of the Company's overall market-based incentive package. Without a long-term incentive plan, the Company would need to increase other aspects of its compensation program, such as base pay or AIP, to provide a competitive pay package for leaders and other key employees. In doing so, the Company would lose the benefit of using the long-term incentive plan to tie the compensation of its leadership to achieving its goal of long-term financial viability and sustainability of the enterprise, which are important for the protection of customers' interests. Together with the AIP, the long-term incentive plan maintains a balanced focus for key employees between goals that have shorter and longer time horizons.

Stock-based compensation plays an important role in focusing senior leadership on how the Company's strategic direction is being evaluated by the financial markets on which it relies for capital and that are uncompromising in their approach to evaluating the quality of leadership and strategy. Moreover, a utility's stock price is an indicator of the confidence investors have in that utility's leadership, its ability to anticipate and respond to the rapid changes in the energy, environmental and regulatory landscape, and the ability of its managerial team to execute on a strategy to meet those changes. Tying an element of compensation to stock price for the most senior leaders ensures that these leaders are not complacent in the face of the changes in the industry.

Q. WHAT IS THE IMPACT OF THESE DISALLOWANCES TO PSNC'S COST-OF-SERVICE?

A. As itemized in Public Staff witness Johnson's Exhibit I, Schedule 3 Page 1 of 4 and Page 2 of 4, the revenue requirement effect of the top five executive compensation adjustments totals $437,871 in disallowances and the AIP and LTIP executive compensation adjustments total $2,410,461 in disallowances. These three adjustments combined represents a total of $2,848,332 in disallowances for reasonable and prudent costs.

Q. DO YOU AGREE WITH PUBLIC STAFF'S DISALLOWANCES OF THESE THREE ITEMS FROM PSNC'S COST-OF-SERVICE?

A. No. These adjustments proposed by Public Staff should be rejected by the Commission.

Q. DOES THIS COMPLETE YOUR REBUTTAL TESTIMONY?

A. Yes, although I reserve the right to supplement or amend my testimony before or during the Commission's hearing in this proceeding.

MS. GRIGG: Thank you. I have a few more documents I'd like to move into evidence, if I may.

COMMISSIONER BROWN-BLAND: Ms. Grigg, maybe you're going to get it, but I just want to be sure. Is -- there's a third exhibit for Witness Phibbs, a confidential exhibit.

MS. GRIGG: Let me double-check. Phibbs -- I'm sorry. Let me double-check, if I may.

That is correct. Yes, ma'am. Confidential Exhibit -- Exhibit 3 of Mr. Phibbs and then request that it -- the confidential treatment be continued.

COMMISSIONER BROWN-BLAND: And that exhibit will be received into evidence and it will remain and be treated as confidential, identified as -- as it was marked when prefiled.

MS. GRIGG: Thank you.

(Phibbs Confidential Rebuttal Exhibit 3 was marked for identification and received into evidence.)

COMMISSIONER BROWN-BLAND: All right. Now, additional documents?

MS. GRIGG: Thank you very much. I move that the following documents be entered into evidence: PSNC's Application for General Increase in Rates and Charges and the G-1 as filed on April 1st, 2021.

COMMISSIONER BROWN-BLAND: All right. Without objection, that motion is allowed. That information is received into evidence.

(PSNC Application for General Increase in Rates and Charges and the G-1 were marked for identification and received into evidence.)

MS. GRIGG: Thank you. I'd also like to move into evidence PSNC's Supplemental G-1 Items filed April 20th, 2021.

COMMISSIONER BROWN-BLAND: All right. That is also allowed.

(PSNC Supplemental G-1 Items were marked for identification and received into evidence.)

MS. GRIGG: I'd like to also move into evidence PSNC's Supplemental G-1 Item 4A as filed with the Commission April 1st, 2021.

COMMISSIONER BROWN-BLAND: Hearing no objection, that motion is, likewise, allowed.

(PSNC Supplemental G-1 Item 4A was marked for identification and received into evidence.)

MS. GRIGG: Thank you. I'd also like to move into evidence the Response of PSNC as filed June 18th, 2021.

COMMISSIONER BROWN-BLAND: June 18th. That motion is also allowed.

(PSNC Response was marked for identification and received into evidence.)

MS. GRIGG: And, finally, I'd like to move into evidence the Stipulation of Settlement entered into among PSNC, Public Staff, CUCA and Evergreen, filed on October 15th, 2021, and the accompanying Stipulation Exhibits A through K filed on that same day.

COMMISSIONER BROWN-BLAND: All right. There being no objection, that motion is allowed.

(Stipulation of Settlement was marked for identification and received into evidence.)

MS. GRIGG: Thank you, Commissioner Brown-Bland. That concludes our case.

COMMISSIONER BROWN-BLAND: All right. Thank you. I believe I'll turn to the Intervenors before we go further.

Let me hear from CUCA.

MR. SCHAUER: Thank you, Commissioner Brown-Bland. I mean, at this time, I believe we'd like to move the testimony of Mr. Kevin O'Donnell into the record, which was filed on September 23rd, 2021, and consisted of a hundred and two (102) pages.

COMMISSIONER BROWN-BLAND: All right. That motion will be allowed and Mr. O'Donnell's testimony will be received and treated as if given orally from the witness stand.

(Whereupon, the prefiled direct testimony of Kevin O’Donnell were copied into the record as if given from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632

In the Matter of
Application of Public Service Company)
of North Carolina, Inc. for a General)
Rate Increase and Charges)

DIRECT TESTIMONY OF

KEVIN W. O'DONNELL, CFA

ON BEHALF OF
CAROLINA UTILITY CUSTOMERS ASSOCIATION

September 23, 2021

Table of Contents

I. INTRODUCTION

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

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

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

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

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

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

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

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

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

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

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

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

	Capital Structure Ratio (%)		Cost Rate (%)	Weighted Cost Rate (%)
	Witness Nelson's Direct Testimony, page 3, **a**	**c = a / b**	Witness Spaulding's Direct Testimony, Exhibit 6 page 2, **d**	**= c * d**
Long-Term Debt	43.79%	43.8%	4.59%	2.01%
Short-Term Debt	1.33%	1.3%	0.24%	0.00%
Common Equity	54.88%	54.9%	10.25%	5.63%
Rx	100.00%	100.00%		7.64%

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

A. The Company's 10.25% equity cost rate is overstated when compared to my Cost of Common Equity Analyses (see **Section VII**: Cost of Common Equity). The Company determined that its equity ratio request of 54.88% was appropriate based on flawed cost of equity analyses that do not reflect market conditions (see **Section VIII**: Review of Cost of Equity Analysis of Witness Nelson). As discussed in the remainder of this testimony, adoption of the Company's requested cost of capital claim would overburden

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

ratepayers, especially in light of the current economic conditions brought on by the COVID-19 pandemic.

Q. PLEASE SUMMARIZE YOUR PRIMARY RECOMMENDATIONS IN THIS CASE.

A. My recommendations in this case are as follows:

- The proper capital structure to use in this proceeding is 50.00% common equity, 48.53% long-term debt, and 1.47% short-term debt;
- The proper cost of long-term debt to use in this case is 4.55% and is 0.24% for short-term debt;
- The proper return on equity on which to set rates for PSNC in this proceeding is 9.00%. This 9.00% recommendation is a market-based cost of equity which will allow the Company to access capital markets, while also ensuring that the rate is fair to the Company's captive customers;
- The overall cost of capital I am recommending in this case is 6.65%;
- The return on equity recommended by Witness Nelson for PSNC of 10.25% is excessive, unreasonable, and not indicative of current market conditions; and
- My recommended rate design is as follows: a 6.83% increase for the residential class; a 6.24% increase for the small general service class; a 3.00% increase for the medium general service class; a 7.85% for the

large general service class; and a 7.62% increase for the large interruptible class.

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

Table 2:CUCA Recommended
Overall Rate of Return

CUCA's Overall Recommendation			
Component	Ratio (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	48.53%	4.43%	2.15%
Short-Term Debt	1.47%	0.24%	0.00%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	**100.00%**		**6.65%**

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

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

A. The equity market has rebounded strongly since the outbreak of the COVID-19 pandemic. Just prior to the pandemic, the S&P 500 index, which represents the 500 largest companies in the United States, was 3,386 as of

February 19, 2020.[2] When the severity of the pandemic sank into the market, the S&P 500 index moved sharply downward to just above 2,237[3] as of March 23, 2020, representing roughly a 1/3 loss in the index. As of July 2, 2021, the S&P 500 index closed over 4,352,[4] representing roughly a 95% gain from the low value that occurred on March 23, 2020. Clearly, investors weathered the storm and are now expecting solid growth from the US and world economies in the near future.

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

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

A. The Company's most recently completed base rate case was filed on March 31, 2016 2019 under Docket No. G-5, Sub 565. In that case, the Company requested an overall rate of return of 8.14% and inclusive of a cost of equity of 10.60% and a capital structure weighted with 53.50% common equity.[5]

[2] Yahoo! Finance, *S&P 500 Historical Data*, *available at* https://finance.yahoo.com/quote/%5EGSPC/history?p=%5EGSPC. (last accessed July 6, 2021).
[3] *Id.*
[4] *Id.*
[5] S&P Global accessed (Sept. 9, 2021).

Ultimately, the Commission approved a settlement of PSNC's 2016 general rate case, which allowed PSNC to increase rates. PSNC was allowed an overall rate of return of 7.53%, inclusive of a 9.70% cost of equity with a capital structure weighted with 52.00% common equity.[6]

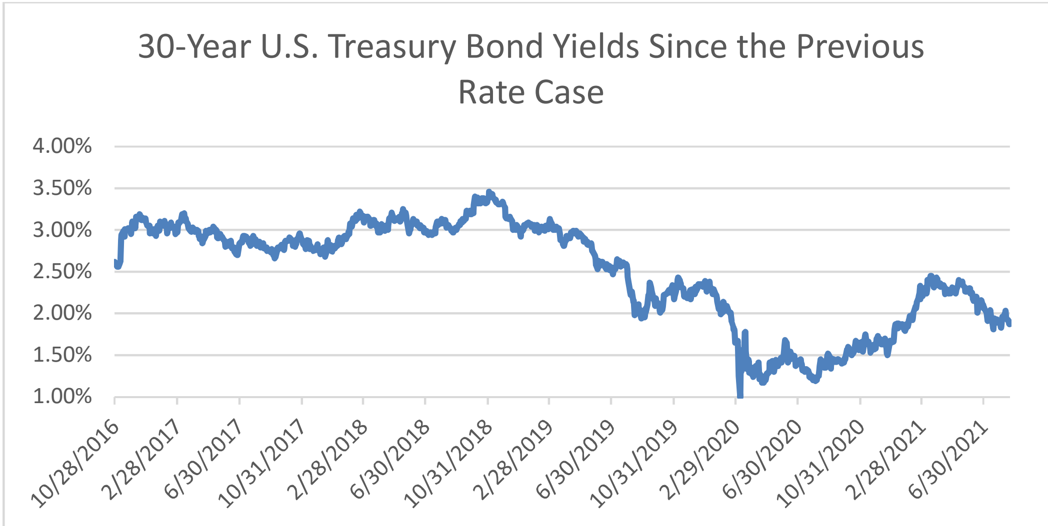
Q. HAS THE DEBT MARKET FOR PSNC CHANGED SINCE THE COMPANY'S 2016 GENERAL RATE CASE?

A. Yes. The debt markets have changed since PSNC filed its 2019 base rate case on April 1, 2019 as exhibited in **Chart 1** below. Within this chart, I have provided the change in the 30-year US Treasury Bond yields from October 28, 2016 to August 20, 2021. The maximum value over this period was 3.46%, the average value was 2.50%, and the minimum value was 0.99%. Refer to **Chart 1** below for further details on the yield on 30-year US Treasury Bonds subsequent to the previous rate case.

---

[6] *Id.*

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



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

A. The Federal Funds Rate is the interest rate that banks charge to one another to borrow or lend excess reserves on hand overnight. This rate plays an important role in the movement of interest rates, and the Federal Reserve's actions over the previous 18-months helps to showcase the steady decline in interest rates from 2018 to 2020. On March 15, 2020, in response to the COVID-19 outbreak and the disruptions to economic activity in this country across the globe, the Federal Reserve reduced the Federal Funds rate to 0.25%.[8]

---

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

[8] *See* Commission of Governors of the Federal Reserve System, *Federal Reserve Issues FOMC Statement* (Mar. 15, 2020), *available at*

The Federal Reserve has since stated that it does not expect to change the Federal Funds Rate at any time in the foreseeable future. Chairman Powell reinforced this view when he said in January 2021 that, "When the time comes to raise interest rates, we'll certainly do that, and that time, by the way, is no time soon."[9] Subsequent to the statements made by Chairman Powell in March 2021, the Federal Reserve explained that although they had sped up their overall expectation for economic growth, they continued to reinforce that they did not see any interest rate hikes likely through 2023.[10] This line of thinking by the Federal Reserve then carried into July 2021 as well.[11]

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

---

https://www.federalreserve.gov/newsevents/pressreleases/monetary20200315a.htm.

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

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

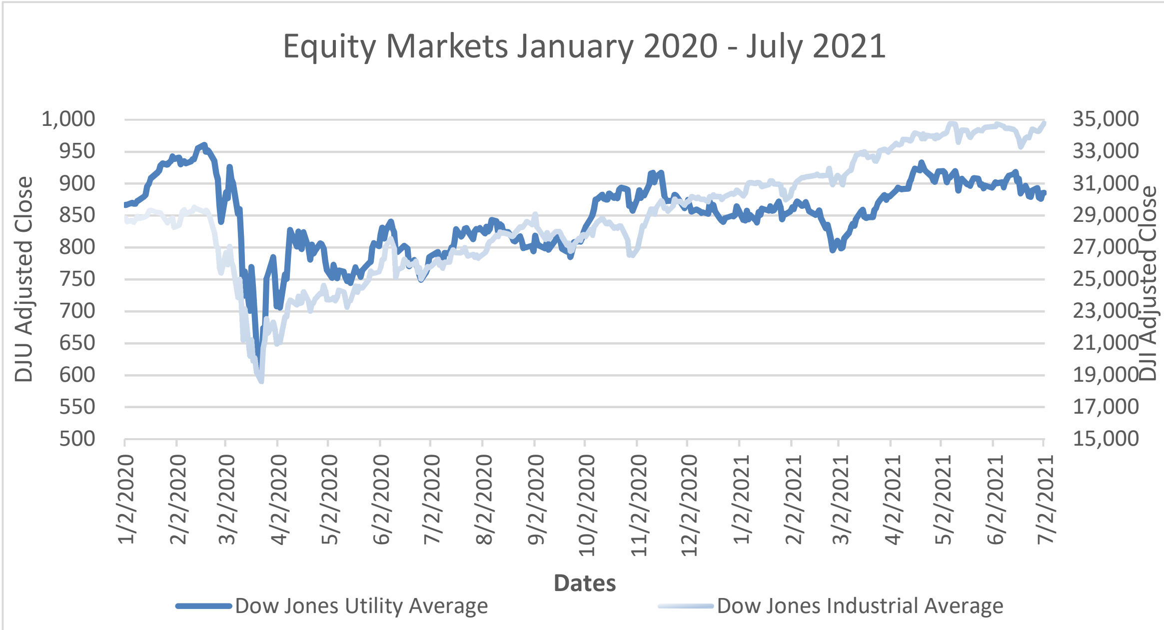
[11] Taylor Tepper & Benjamin Curry, *July 2021 FOMC Meeting: Fed Keeps Policy Unchanged As Pressure To Taper Increases*, Forbes Advisor (Jul. 28, 2021), *available at* https://www.forbes.com/advisor/investing/fomc-meeting-federal-reserve/.

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

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

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

Chart 2: DJIA to DJUA Comparison[12]



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

---

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

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

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

> Several utilities, including Xcel Energy and NextEra Energy Inc. subsidiary Florida Power & Light Co., which issued $1.1 billion in first mortgage bonds, are "*using the opportunity to take advantage of attractive borrowing costs, so there does not appear to be an inability to access capital*," they said.
>
> "*Utilities are reporting that recent deals have been significantly (7x) oversubscribed, highlighting that the capital markets are open for investment grade-rated utilities*," the analysts wrote. "*At the same time, we have also observed some utility companies that have fully drawn their bank lines as a precaution to provide them with liquidity in the event that markets seize up*," such as Dominion Energy Corp. and American Electric Power Co. Inc.[13]

Additionally, during the midst of the early stages of the COVID-19 pandemic on April 29, 2020, S&P Global Market Intelligence published an article entitled "Utility sector 'far and away' least impacted by EPS estimate

---

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

cuts."[14] Note that on the date that this article was published, markets were at their most volatile during the early stages of the COVID-19 pandemic. The article provided the following observation:

> The S&P 500 utility sector has "far and away" experienced the least impact from earnings revisions since Feb. 28, the corporate bond research firm found. Despite market turmoil and the ongoing economic downturn, analysts have only cut earnings per share expectations for stocks in the utility sector by an average 1% for 2020 and 2021, according to CreditSights.
>
> By comparison, consumer staples, the next least-impacted sector, saw an average 5% decrease to EPS estimates for both years. Technology followed with a 9% estimate cut for 2020 and 2021.
>
> CreditSights pulled the data to measure the consensus view that utilities provide a safe harbor to investors. "*Water is wet, the sun will rise in the east and U.S. utilities are a defensive sector, but how defensive? Very defensive,*" CreditSights analysts Andrew DeVries and Nick Moglia wrote in an April 29 research note.[15]

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

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

Gains, Solid ROEs Despite COVID-19 Pandemic." The S&P Global Market Intelligence article noted:

> Despite the significant challenges caused by an economy that continued to be negatively impacted by COVID-19, utilities overall posted solid earnings growth and earned returns on equity during the third quarter, illustrating the tenet that utility finances hold up comparatively well in challenging economic environments.[16]

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

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

A. As shown in **Chart 2**, equity markets were negatively impacted during the first two quarters of 2020, before later rebounding during the second half of 2020 and into 2021. During the majority of 2020, businesses were closed, and workers stayed home as the United States and world economies slowed

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

dramatically prior to the beginning of phased reopening plans around the world. While I note that the economic recovery that began during the latter part of 2020 has continued into 2021, and that there is an expectation that the economy will continue its rebound throughout 2021, there is no current expectation that the economy will fully recover, or that the sustained civilian unemployment rate will reach pre-2020 levels, at any point in the near-term.

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

> Economic activity has continued to recover from its depressed second quarter level. The reopening of the economy led to a rapid rebound in activity, and real gross domestic product, or GDP, rose at an annual rate of 33 percent in the third quarter. In recent months, however, the pace of the improvement has moderated…The economic downturn has not fallen equally on all Americans, and those least able to shoulder the burden have been the hardest hit...The economic dislocation has upended many lives and created great uncertainty about the future…As we have emphasized throughout this pandemic, the outlook for the economy is extraordinarily uncertain….[17]

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

> The overall recovery in economic activity since last spring is due importantly to unprecedented fiscal and monetary

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

> policy actions, which have provided essential support to households, businesses, and communities. The recovery has progressed more quickly than generally expected, and forecasts from FOMC participants for economic growth this year have been revised up notably since our December Summary of Economic Projections…As with overall economic activity, conditions in the labor market have turned up recently. Employment rose by 379,000 in February, as the leisure and hospitality sector recouped about two-thirds of the jobs that were lost in December and January. Nonetheless, employment in this sector is more than 3 million below its level at the onset of the pandemic. For the economy as a whole, employment is 9.5 million below its pre-pandemic level. The unemployment rate remains elevated at 6.2 percent in February; this figure understates the shortfall in employment, particularly as participation in the labor market remains notably below pre-pandemic levels.[18]

Chairman Powell also noted on April 12, 2021 that, "The recovery, though here, remains uneven and incomplete. <u>The burden is still falling on lower-income workers and the unemployment rate in the bottom quartile is still 20 percent</u>."[19] Additionally, Michelle Bowman (Federal Reserve Board Governor) stated on May 5, 2021 that:

> The economic recovery is not yet complete, and the uncertain course of the pandemic still presents risks in the near term…Despite the progress to date and the signs of acceleration in the recovery, employment is still considerably short of where it was when the pandemic disrupted the economy and it is well below where it should be, considering the pre-pandemic trend.[20]

---

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

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

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

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

> The latest jobs report reminds us that while there are good reasons to expect the number of jobs and the number of people wanting to work will make a full recovery, it is unlikely they will recover at the same pace…Job losses are disproportionately concentrated in low-wage, high-contact sectors, suggesting that workers least able to shoulder the economic effect of job loss have faced the greatest challenges.[21]

Chairman Powell reiterated this line of thinking as recently as July 2021, when he noted that more economic improvement and sustained stability was needed before the Fed would entertain doing anything that would negatively impact economic activity. Chairman Powell noted that this was the case given that the United State was still "8.5 million jobs from where we were in February of 2020."[22]

As referenced in the quotes above, although there has been considerable growth and recovery within the capital markets over the second half of 2020, and into 2021, the individuals within PSNC's customer base that were most negatively impacted by the pandemic are still struggling with such issues. Even while economic growth within the markets has

---

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

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

grown at a rate faster than anticipated as COVID-19 cases declined and economies began to reopen, there are key indicators (such as employment figures) that remain depressed. As such, any additional rate increases would only continue to exacerbate the negative economic circumstances encountered by this portion of PSNC's consumer base.

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

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

Many consumers at the residential, commercial, and industrial levels have struggled to pay their utility bills as unemployment levels spiked during 2020 and remained higher than average into the second half of 2020 and into 2021, with various businesses also shut down for extended time over this period.

For instance, while the financial markets began a rebound in the third quarter of 2020, the average civilian unemployment rate still exceeded what was common in prior periods. The unemployment rate was heightened at 6.77% in Q4 2020 and averaged 8.12% during the entirety of 2020.[23] For comparison purposes, the average monthly civilian unemployment rate from 2019 was 3.67%.[24] While the unemployment rate improved through the second half of 2020 and into 2021, it still averaged 6.17% for Q1 2021 and 5.93% for Q2 2021.[25]

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

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

A. In PSNC's most recently concluded base rate case from 2019, PSNC Witness Robert Hevert recommended a 10.60% market-based ROE.[26] In the current proceeding in 2021, Ms. Nelson has recommended a 10.25% ROE as market-based.

Based upon my cost of equity analyses discussed below, a market-based cost of equity for PSNC should be no higher than 9.00%. The Commission's determination of an appropriate cost of equity must consider

---

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

the needs of the consumers, and not just the interests of PSNC. Many of PSNC's customers are still dealing with ongoing financial struggles linked to a variety of factors, such as higher than average unemployment numbers throughout 2020 and 2021. My recommended cost of capital for PSNC's is based upon a careful analysis of current financial data, disciplined application of cost of equity models to an appropriate proxy group of natural gas utilities, and identification of an appropriate capital structure for setting rates. My cost of capital recommendation for PSNC balances the Company's need to access the markets and the interests of consumers who will be asked to pay the rates for essential natural gas distribution utility service.

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

A. I recognize that on July 13, 2021, the Consumer Price Index ("CPI") reported that inflation results had increased by 5.4% year to date through June 2021, which was higher than anticipated by economists and the market.[27] However, this report of inflation is too early to predict whether the United States economy will seriously suffer permanently in the long

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

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

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

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

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

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

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

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

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

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

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

> A public utility is entitled to such rates as will permit it to earn a return upon the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings

> which are attended by corresponding risks and uncertainties; but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit, and enable it to raise the money necessary for the proper discharge of its public duties.[28]

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

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

> [T]he return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain credit and attract capital.[29]

[28] 262 U.S. at 692.
[29] 320 U.S. at 603.

IV. DEVELOPMENT OF PROXY GROUP

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

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

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

Additionally, unlike Ms. Nelson, I have chosen to perform an analysis directly on Dominion Resources. PSNC is a wholly owned subsidiary of Dominion Resouirces. As such, I found it appropriate to perform a specific, singular analysis of Dominion Resources, as it provides the most directly observable link between any company within the comparable proxy group and PSNC.

Q. WHY DID YOU CHOOSE TO INCLUDE UGI CORP, CHESAPEAKE, AND NISOURCE WITHIN YOUR COMPARABLE GROUP, WHILE MS. NELSON OMITTED THE COMPANY FROM HER ANALYSIS?

A. Within her direct testimony, Ms. Nelson stated that in developing her proxy group, she first began with the ten companies included in *Value Line's* Natural Gas Utility industry.[30] However, she then subjected those ten companies to a screening process where she opted to remove Chesapeake Utilities, NiSource, and UGI Corp.

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

Additionally, please note that in reference to my proxy group, I am aware UGI Corp. announced on December 30, 2020 their plan to purchase

[30] Witness Nelson Direct Testimony,

Mountaineer Gas in West Virginia.[31] As of July 21, 2021, the deal has not closed. Normally, I would not include a company in my proxy group that is in the middle of an acquisition. However, in this case, I am including UGI for the following two reasons: First, Mountaineer Gas is quite small relative to UGI (about 6% in total assets); and second, the natural gas proxy group is already small so eliminating a company may allow another entity to skew the results of the group.

Q. PLEASE EXPLAIN WHY YOU PERFORMED A COST OF EQUITY ANALYSIS SEPARATELY ON DOMINION RESOURCES.

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

V. CAPITAL STRUCTURE

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

A. The term "capital structure" refers to the relative percentage of debt, equity, and other financial components that are used to finance a company's

[31] https://www.ugicorp.com/investors/press-releases/press-releases-details/2020/UGI-to-Acquire-Mountaineer-Gas-Company/default.aspx

investments. A company's capital structure typically includes some combination of three principal financing methods.

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

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

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

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

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

Q. HOW DOES CAPITAL STRUCTURE IMPACT THIS CALCULATION?

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

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

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

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

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

A. No. PSNC's stock is owned by Dominion, which is the parent holding company for several utilities. As the owner of these utilities, Dominion is able to set the capital structure of these utilities as it sees fit. For example, Dominion, which had a common equity ratio at the conclusion of 2020 of 39.50%,[32] could issue debt and then infuse this debt into PSNC and call it common equity. In such a circumstance, Dominion could use the regulatory system to issue debt at an interest rate of approximately 3.5% and then invest those funds into PSNC as common equity to produce a pre-tax rate of return for stockholders of over 9%. The alternative to Dominion is to issue debt and then support that debt issuance with debt from PSNC. In

[32] *The Value Line Investment Survey*, August 13, 2021 (Electric Utilities East).

either event, the capital structure of PSNC is, for the most part, at the discretion of its parent company, Dominion.

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

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

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

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

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

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

A. Yes, I have.

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

A. PSNC has proposed the following capital structure:

Table 3: PSNC's Requested Capital Structure

	Capital Structure Ratio (%)		Cost Rate (%)	Weighted Cost Rate (%)
	Witness Nelson's Direct Testimony, page 3, **a**	**c = a / b**	Witness Spaulding's Direct Testimony, Exhibit 6 page 2, **d**	**= c * d**
Long-Term Debt	43.79%	43.8%	4.59%	2.01%
Short-Term Debt	1.33%	1.3%	0.24%	0.00%
Common Equity	54.88%	54.9%	10.25%	5.63%
Rx	100.00%	100.00%		7.64%

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

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

Table 4: Proxy Group Equity Ratio[33]

Company	2019 Ratio	2020 Ratio	2021E Ratio	2024E–2026E Ratio
Atmos Energy	62.00%	60.00%	52.00%	60.00%
Chesapeake Utilities	56.10%	57.80%	57.00%	60.00%
New Jersey Resources	50.20%	44.90%	46.00%	47.00%
NiSource Inc.	36.90%	32.90%	40.00%	40.00%
Northwest Natural	51.80%	50.80%	51.00%	57.00%
ONE Gas Inc	62.30%	58.50%	36.00%	53.00%
South Jersey Inds	40.80%	37.40%	37.00%	39.50%
Southwest Gas	52.10%	49.50%	49.50%	52.00%
Spire Inc	55.00%	51.00%	51.00%	55.00%
UGI Corp	39.80%	40.80%	43.50%	50.00%
Average	**50.70%**	**48.36%**	**46.30%**	**51.35%**
Dominion Energy[34]	45.00%	39.50%	39.00%	41.00%

As can be seen in the table above, the average common equity ratio for the proxy group in 2019 was 50.70%, the average common equity ratio for 2020 was 48.36%, the average expected common equity ratio for 2021 is 46.30%, and the average expected common equity ratio from 2024–2026 is 51.35%. Additionally, the respective ratios for Dominion for the same periods noted above are 45.00%, 39.50%, 39.00% and 41.00%, respectively. Each of these metrics is below the Company's requested equity ratio in this case of 54.88%

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

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

A. Note that I have sourced the average common equity ratio values granted by utility regulators for gas utilities from across the country from *S&P Global*. In my research into these numbers, I found that four states included within the overall average value of gas utilities across the country report their allowed common equity ratios on an all capital sources basis (*i.e.,* LT Debt, ST Debt, Common Equity, Preferred Stock, Customer Deposits, Deferred Income Taxes, Investment Tax Credits). As such, I have removed these four states (*i.e.,* Arkansas, Florida, Indiana and Michigan) from these numbers to ensure that each of the states included in this average report their allowed common equity ratio percentages only on investor sources of capital (*i.e.,* LT Debt, ST Debt, Common Equity). I wanted to remove these four states from the overall average to ensure that the average represented an appropriate comparison, given that PSNC's requested equity ratio in this case of 54.88% is based solely off of investor sources of capital.

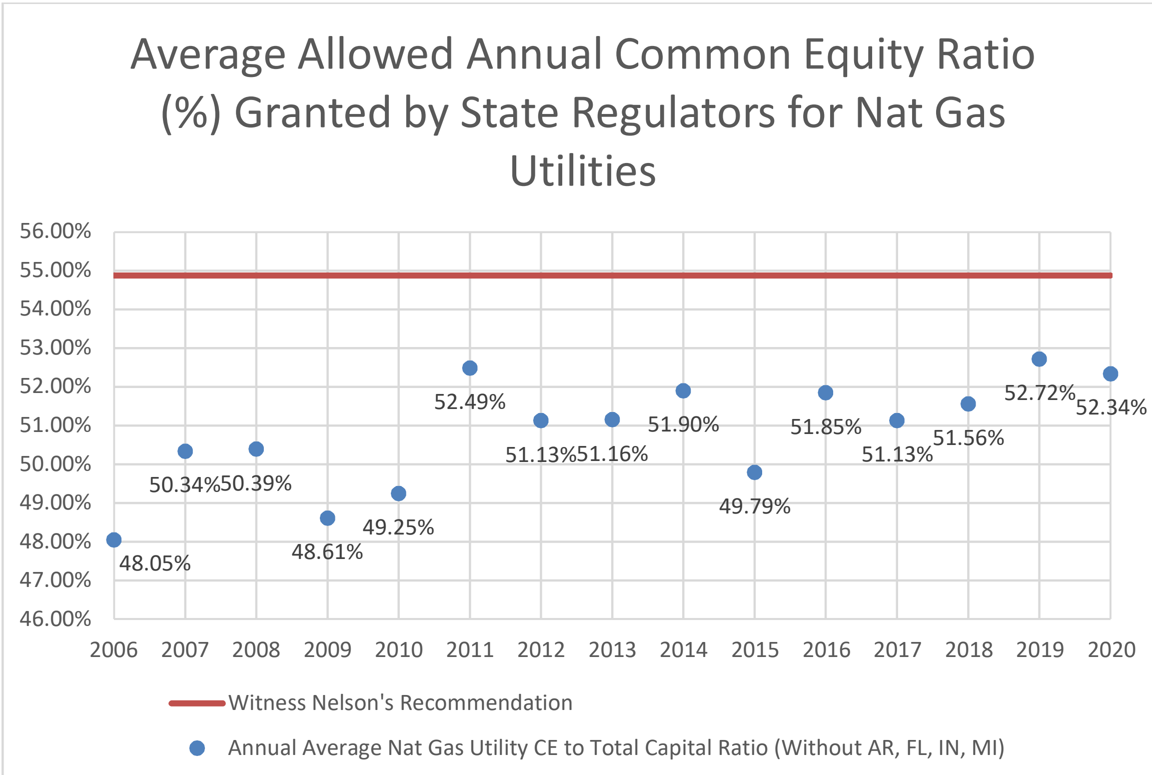
The resulting average common equity ratio granted by regulators for natural gas utilities for all states on an investor-sources basis in 2020 was 52.34%.[35]

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

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

A. State regulators have been quite consistent in their rulings in natural gas cases for allowed common equity ratios based on investor sources of capital over the past 15 years. From 2006 through 2020, common equity ratios have ranged from 48.05% to 52.71%, with an average of 50.85%. If one were to evaluate this data over the previous 12 years, the average common equity ratio over this period is 51.16%, the average ratio over the previous 10 years is 51.61%, and the average ratio over the previous 8 years is 51.56%. In **Chart 4** below I have presented the average annual common equity ratio granted by state regulators for each year over the past 15 years.

Chart 4: Common Equity Ratio Granted by State Regulators (2006–2020)[36]



Q. WHAT IS THE CAPITAL STRUCTURE OF DOMINION, THE PARENT HOLDING COMPANY OF PSNC?

A. As shown in **Table 4** above, the Dominion equity ratio for 2020 was 39.00%, and is expected by analysts to be at 41.00% through the 2024E-2026E time period.

[36] *Id.*

Q. IS THE CAPITAL STRUCTURE OF PSNC RELATED TO THE CAPITAL STRUCTURE OF DOMINION?

A. Yes. Dominion controls the amount of debt and equity in the PSNC capital structure. The fact that PSNC is asking for a very high equity ratio of nearly 55%, while Dominion had a 39.00% equity ratio at the end of 2020,[37] indicates that the holding company is using double-leverage to increase profits from its regulated subsidiary, PSNC.

Q. PLEASE EXPLAIN THE CONCEPT OF DOUBLE LEVERAGE.

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

Q. PLEASE PROVIDE AN EXAMPLE OF DOUBLE-LEVERAGE.

A. An example would be a parent holding company issuing debt at 3.5% and then infusing the debt proceedings into the utility subsidiary as equity where the utility earns an allowed ROE of 9.0%. Keep in mind that the regulated utility is allowed to recover its income taxes so the 9.0% is actually grossed up to approximately 12.5% to pay for income taxes. As a result, through the

[37] *The Value Line Investment Survey*, August 13, 2021.

regulatory process, Dominion can issue debt at 3.5% and turn it into 12.5% through double-leverage through its relationship with its subsidiaries.

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

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

Table 5: Common Equity Ratio Comparison

PSNC's Eq Ratio Request	54.88%
CUCA Eq Ratio Recommendation	50.00%
2019 O'Donnell Proxy Group Actual Eq Ratio Average	50.70%
2020 O'Donnell Proxy Group Actual Eq Ratio Average	48.36%
2021E O'Donnell Proxy Group Expected Eq Ratio Average	46.30%
2024E – 2026E O'Donnell Proxy Group Expected Eq Ratio Average	51.35%
2019 Dominion Actual Eq Ratio Average	45.00%
2020 Dominion Actual Eq Ratio Average	39.50%
2021E Dominion Expected Eq Ratio Average	39.00%
2024E – 2026E Dominion Expected Eq Ratio Average	41.00%
2020 Average Annual Regulator Nat Gas Granted Eq Ratio	52.34%
2006 – 2020 Average Annual Regulator Nat Gas Granted Eq Ratio	50.85%

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

A. No. The requested capital structure for PSNC of 54.88% is not as reasonable as a recommended capital structure of 50.00% for ratemaking purposes. Nothing in the make-up of PSNC suggests that it requires an equity ratio in a range that would place it higher than that of the companies within its comparable proxy group. Indeed, some of the companies in the proxy group are involved in a wider array of business activities that involve more business risk than a utility's distribution of natural gas within its monopoly service territory. As such, if anything, the financial risk (as represented by the equity ratio) of the comparable company proxy group should be higher, not lower, than a traditional gas utility such as PSNC. Customers of PSNC should not pay higher rates associated with a capital structure that consists of so much common equity which, as previously discussed, is more expensive than debt.

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

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

Table 6: CUCA Recommended Capital Structure

CUCA's Overall Recommendation			
Component	Ratio (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	48.53%	4.43%	2.15%
Short-Term Debt	1.47%	0.24%	0.00%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	**100.00%**		**6.65%**

Note that the CUCA recommended overall debt ratio of 50% was split into a long-term debt ratio of 48.53% and short-term debt ratio of 1.47%. This split was based upon the same ratio used by the Company for its split of its recommended overall debt ratio of 45.12% into a long-term debt ratio of 48.53% and a short-term debt ratio of 1.47%. As such, I have used those same, specific ratios of long-term debt to total debt and short-term debt to total debt to split out CUCA's recommended overall 50% debt portion of the capital structure between short-term and long-term debt.

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

A. Note that my specific equity recommendations in this proceeding based on the analyses performed is a capital structure weighted 50% to common equity, along with a 9.00% ROE, as shown in **Table 2**. However, if the Commission were to adopt a capital structure for PSNC at the level requested by the Company of 54.88%, the Commission should recognize the lower financial risk applicable to PSNC with such an equity ratio, and accordingly reduce the allowed ROE in this proceeding.

VI. COST OF DEBT

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

A. No. I am recommending a slightly lower cost of long-term debt for PSNC due to a credit rating downgraded that stems from the decision of Dominion Resources to purchase SCANA Corp. As part of the merger agreement that PSNC/Dominion entered into with the Public Staff of the NCUC when Dominion acquired SCANA, PSNC agreed to a "hold harmless" provision in regard to higher interest costs that may result from a credit downgrade due to the acquisition.

The merger agreement, which the NCUC approved, also contained a "stay out" provision that prevented PSNC from raising rates prior to November 2021. On January 31, 2020, PSNC's credit rating was downgraded from A3 to Baa1. In its report announcing the downgrade, Moody's cited declining credit metrics resulting from capital expenditures being financed with long-term debt and the stay-out provision[38] which stemmed from the acquisition of SCANA by Dominion.

[38] Moody's Investors Services, Rating Action: Moody's upgrades SCANA to Baa3 and DESC to Baa2; downgrades PSNC to Baa1. All outlooks are stable.

PSNC agreed as a merger condition not to charge consumers a higher rate of interest that may have resulted from the merger. A higher rate of interest for PSNC bonds issued after January 31, 2020 has occurred so I have adjusted the $200 million debt issuance of PSNC issued on March 30, 2020. Specifically, I reduced the coupon rate of that issuance by 17 basis points such that the embedded cost of debt in my recommendation is 4.55%.

Q. PLEASE EXPLAIN HOW YOU ARRIVED AT THE DECISION TO REDUCE PSNC'S MARCH 30, 2020 DEBT ISSUANCE BY 17 BASIS POINTS.

A. Prior to Janunary 31, 2020, PSNC had a Moody's credit rating of "A." After the downgrade, PSNC had a Moody's credit rating of "Baa1." Naturally, a company with a credit rating of "A" is going to pay less than a company with a credit rating of "Baa1." The amount of the interest rate differential between two credit ratings ("A" vs. "Baa1") is called a yield spread.

The Mergent Bond Record is a financial publication that tracks yields by corresponding credit ratings. By comparing "A" to "Baa1" rated bonds, I was able to determine an average yield spread over various time periods. The first time period I examined was from January 2011 through May 2021. Over this time period, the average spread was 54 basis points. I next examined the actual month that the March 2020 PSNC debt issuance was placed into the market and found the spread between the "A" and "Baa1" bonds was 46 basis points. I normally do not recommend point months in such an analysis but, given the Covid pandemic that was beginning to impact the markets in March 2020, I did examine the spread for that month.

The average of the two examined periods was 50 basis points (54 basis points for January 2011 through May 2021, and 46 basis point in March 2020). Given that there are 3 notches in a single credit rating, I divided the 50 basis points by 3 to arrive at a decrement of 17 basis points. My calculations can be seen in the table below.

Table 7: Calculation of Yield Spread Differential

	Public Utility Bonds		
Period Examined	**A-Rated**	**Baa-Rated**	**Spread**
Jan 2011 thru May, 2021	4.06	4.61	0.54
March 2020	3.50	3.96	0.46
Average Spread			**0.50**
One-Notch Spread			0.17

I reduced the PSNC March 2020 bond issuance by 17 basis points and recalculated the embedded cost of debt for PSNC to be 4.43%. As a result, I am recommending an embedded cost of debt of 4.43% in this proceeding.

VII. COST OF COMMON EQUITY

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

A. In North Carolina, as in virtually all regulatory jurisdictions, a utility's rates must be "just and reasonable."[39] Thus, regulation recognizes that utilities are entitled to an opportunity to recover the reasonable and prudent costs of providing service, and the opportunity to earn a just and reasonable rate of return on the capital invested in a utility's facilities, such as natural gas distribution equipment, buildings, vehicles, and similar long-lived capital assets.

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

A. Regulatory commissions and boards, as well as financial industry analysts, institutional investors, and individual investors, use different analytical models and methodologies to estimate/calculate reasonable rates of return on equity. Among the measures used are the Discounted Cash Flow

[39] https://www.ncuc.net/Aboutncuc.html

("DCF") Model, the Comparable Earnings Analysis ("CEA"), and the Capital Asset Pricing Model ("CAPM"). I believe the most useful methodology is the DCF analysis, but I have also presented the CEA and the CAPM within this testimony as checks for my DCF results.

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

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

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

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

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

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

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

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

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

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

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

Q. PLEASE EXPLAIN THE DISCOUNTED CASH FLOW MODEL.

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

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

Let D = dividends per share in the initial future period

g = expected growth rate in dividends

k = cost of equity capital

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

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

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

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

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

Solving for k yields:

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

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

A. Yes, I believe that they do. There are two primary reasons for my conclusion. First, there is much literature that supports the fact that, while emotional or so-called "irrational" behavior in the short term may affect (and has affected) share prices, over the long term, a company's financial fundamentals drive the market.[40] Secondly, analysts give great weight to earnings, dividend, and book value growth in formulating their recommendations to clients.

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

Q. IS THE DCF FORMULA STRAIGHTFORWARD?

---

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

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

Q. CAN YOU PROVIDE AN EXAMPLE?

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

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

A. I have calculated the appropriate dividend yield by averaging the dividend yield expected to be paid over the next 12 months for each comparable company, as reported by the *Value Line Investment Survey*. The period covered is from May 21, 2021, through August 13, 2021. To study the short-term, as well as long-term, movements in dividend yields, I examined the 13-week, 4-week, and 1-week dividend yields for my comparable group. These results appear in **Exhibit KWO-2** and show an average dividend yield for the 13-week period of 3.3%, the 4-week period of 3.3%, and the 1-week period of 3.3% for the comparable company proxy group. I have also presented the results for Dominion within **Exhibit KWO-2** as PSNC's parent company. The values for Dominion over these same periods were 4.0%, 4.1%, and 4.2%, respectively.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Additionally, the historical growth rates for Dominion ranged from a EPS of -1.5% to a DPS of 7.5% over the 10-year historical period and a EPS of -5.0% to a BPS of 9.0% over the 5-year historical period.

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

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

A. The forecasted growth rates from *Value Line* for the proxy group range from 5.1% (DPS) to 7.6% (EPS). Additionally, the forecasted *Value Line* growth rates for Dominion ranged from -1.5% (DPS) to 12.0% (EPS).

In addition to the above forecasted *Value Line* growth rates, the average plowback (retained to common equity) growth rate for the proxy group is 4.2% (**Exhibit KWO-2** and **Exhibit KWO-3**), the *CFRA* 3-year forecasted EPS growth rate is 5.8% (**Exhibit KWO-2**), and the *Schwab* LT Growth Rate 3-5 year forecasted EPS growth rate is 5.8% (**Exhibit KWO-2**). These values for Dominion are 4.3%, 7.0%, and 6.7%, respectively.

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

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

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

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

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

A. The average dividend yield for the comparable company proxy group for the 13-week period was 3.3%, the 4-week time period was 3.4%, and the 1-week period was 3.4%. Additionally, the average dividend yield for Dominion for the 13-week period was 4.0%, the 4-week time period was 4.1%, and the 1-week time period was 4.2%.

With the second portion of the DCF analysis relating to growth rates, for the comparable group, I note that the historical growth rates range from 4.4% to 5.9% and the forecasted growth rates range from 5.1% to 7.6%. For Dominion, the historical range is from -5.0% to 9.0% and the forecasted range is from -1.5% to 12.0%.

I have included both historical and forecasted growth rate figures within my analysis as previously noted as shown within both **Exhibit KWO-5** and **Exhibit KWO-6** to present the full set of growth rate information applicable within this cost of capital analysis for both my comparable proxy group, as well as PSNC's parent company, Dominion.

Table 7 below showcases the Dividend Yield Range values from the 13-week, 4-week, and 1-week dividend yield periods, plus the Historical Growth Rates from *Value Line*, the Forecasted Growth Rates from *Value Line*, *CFRA*, and *Schwab*, and the Plowback Growth Rates from *Value Line* for my comparable company proxy group, as well as for PSNC's parent company, Dominion.

Table 7: DCF Results

Natural Gas DCF Results: Proxy Group (as sourced from **Exhibit KWO-5**)			
	Minimum	Average	Maximum
Value Line Historical Growth Rate Averages + *Value Line* Div Yield Range	8.1%	8.6%	8.9%
Forecasted Growth Rate Averages + *Value Line* Div Yield Range	8.4%	9.7%	11.0%
Value Line Plowback Growth Rate Averages + *Value Line* Div Yield Range	7.5%	7.5%	7.6%
Average (Rx)	8.0%	8.6%	9.2%
DCF Results: Dominion Parent Company (as sourced from **Exhibit KWO-6**)			
	Minimum	Average	Maximum
Value Line Historical Growth Rate Averages + *Value Line* Div Yield Range	0.8%	7.9%	11.7%
Forecasted Growth Rate Averages + *Value Line* Div Yield Range	2.5%	9.8%	16.2%
Value Line Plowback Growth Rate Averages + *Value Line* Div Yield Range	8.3%	8.4%	8.5%
Average (Rx)	3.9%	8.7%	12.1%

As shown in **Exhibit KWO-1**, I have utilized an ultimate DCF result range of 7.50% to 9.50%. This range was determined based upon a review of the values shown in the table above. My 7.50% to 9.50% range was positioned towards the high end of the range of values shown within **Table 7** above, with the low-end of the range of 7.50% being set below the average of the minimum values for the proxy group (8.0%), and the high-end of the range of 9.50% being set above the average of the maximum values for the proxy group (9.2%). As such, I have placed my overall DCF result at 9.00%, which is above the midpoint of my 7.50% to 9.50% range in order to take into account the higher forecasted growth rates moving forward.

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

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

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

Q. PLEASE DESCRIBE YOUR FIRST COMPARABLE EARNINGS ANALYSIS.

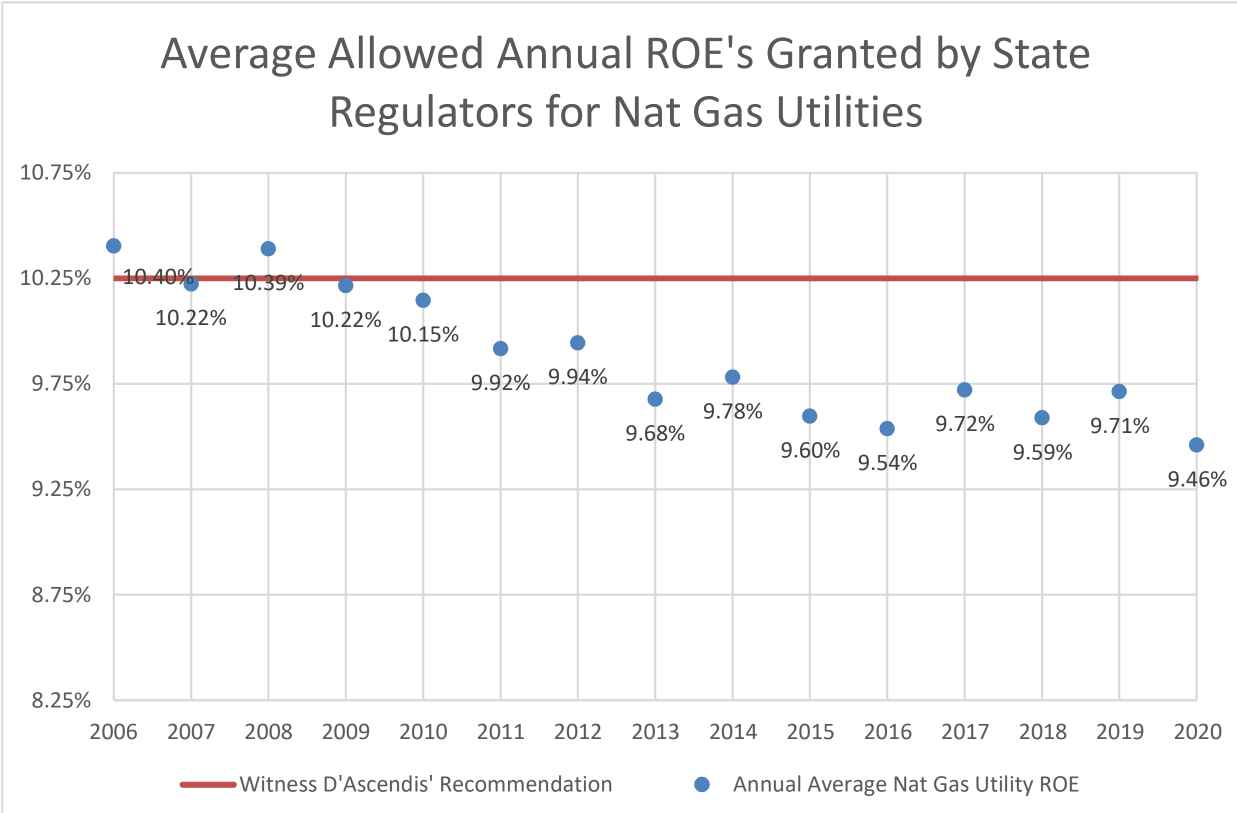
A. As noted above, an appropriate CEA should be applied to comparable companies of similar risk. **Exhibit KWO-4** presents a list of historic and forecasted earned returns *on book value equity* of the proxy group over the period from 2019 through 2026E. I picked this range to provide the Commission with at least two periods of historical returns (*i.e.,* 2019 and 2020) and a forecasted return period of at least 5 years (*i.e.,* 2021E through 2026E). As can be seen in this exhibit, the average earned returns on equity for the comparable company proxy group range from 9.2% (2019 and 2020) to 9.7% (2021E and 2024E–2026E). Additionally, for PSNC's parent company Dominion, this range was from 6.2% (2019) to 12.5% (2021E).

Q. PLEASE DESCRIBE YOUR SECOND COMPARABLE EARNINGS ANALYSIS.

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

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

Chart 5: Allowed ROEs 2006 – 2020[41]



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

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

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

A. Based on the above-stated findings, I believe the proper rate of return using a CEA is in the range of 9.00% to 10.00%. The 9.00% low end of this range is aligned with the low end of the range of the comparable company proxy group from 2019–2026E shown in **Exhibit KWO-4** for 2019 and 2020 of 9.2%. The 10.00% high end of the range is above the high end of the range of the comparable company proxy group from 2019–2026E shown in **Exhibit KWO-4** for 2021E and 2024E-2026E of 9.7%. Note that the ROE granted by state regulators in 2020 of 9.46% (see **Chart 5**) and the average ROE granted by state regulators from 2006–2020 of 9.89% fit within this 9.00% to 10.00% CEA range as well.

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

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

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

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

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

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

Q. PLEASE EXPLAIN THE CAPITAL ASSET PRICING MODEL.

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

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

Where:

Rf is the risk-free rate;

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

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

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

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

$$ROE = Rf + (Beta * Risk\ Premium)$$

Where:

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

Q. HOW IS THE RISK-FREE RATE MEASURED?

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

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

A. Economic forecasters, as well as the Federal Open Market Committee (FOMC), all believed in previous years that the current interest rate environment was expected to remain relatively stable for many years to come. However, the FOMC implemented rate cuts throughout the early stages of 2019 and then, in its December 2019 meeting, announced plans to keep interest rates at current levels throughout 2020.[42] This announcement occurred before the COVID-19 pandemic that played havoc on the markets throughout Q1 and Q2 2020 before the market began to rebound during Q3 and Q4 2020. In response to the impact the pandemic had on the market, on March 3, 2020 the FOMC decreased the Federal Funds Rates 50-basis points to a targeted range of between 1% and 1.25% in response to recent market conditions.[43] Additionally, on March 16, 2020 the FOMC dropped interest rates to near 0%.[44] As such, the interest rate market was unexpectedly turbulent during 2020 due largely to the COVID-19 pandemic.

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

---

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

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

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

2020,[45] when the 30-year U.S. Treasury Bond Yield on that date was 2.89%.[46] Even with the rise in rates above 2.00%, rates are not expected to rise back to, and then sustain, levels near 2.89% again at any time in the near term. As such, the market remains in a low overall interest rate environment.

Q. HOW IS BETA MEASURED IN THE CAPM?

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

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

A. The development of the current market risk premium is, undoubtedly, the most controversial aspect of the CAPM calculations. To gauge the historical risk premium, I turned to the Ibbotson database published by *Morningstar,*

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

Duff & Phelps, and the *CFA Institute Research Foundation*. In **Table 8** below, I have presented both the long-term geometric mean and arithmetic mean returns for equities and fixed income securities and the resulting risk premiums.

Table 8: Equity Risk Premium Calculations[47]

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

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

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

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

A. On January 20, 2021, Morningstar.com published an article entitled "Experts Forecast Stock and Bond Returns 2021 Edition."[48] This article was

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

[48] Christine Benz, *Experts Forecast Stock and Bond Returns: 2021 Edition*, Morningstar (Jan. 20, 2021), *available at*

provided as part of Morningstar's annual stock and bond return forecast series. Note that by referring to future returns, the market experts referenced below are discussing the overall total market returns, and not just the equity risk premium. Below are some of the market return forecasts from the previously referenced article:

<u>Blackrock</u>

5% 10-year expected nominal return from US equities.[49]

<u>Grantham Mayor Van Otterloo ("GMO")</u>

Negative 5.8% real (inflation-adjusted) returns for US large caps over the next seven years.[50]

<u>JP Morgan</u>

4.1% nominal returns for US equities over a 10–15-year horizon.[51]

<u>Morningstar Investment Management</u>

Negative 0.1% 10-year nominal returns for US stocks.[52]

<u>Research Affiliates</u>

2% nominal (negative 0.2% real) returns for US large caps during the next 10 years.[53]

<u>Vanguard</u>

---

https://www.morningstar.com/articles/1018261/experts-forecast-stock-and-bond-returns-2021-edition.

[49] *Id.*

[50] *Id.*

[51] *Id.*

[52] *Id.*

[53] *Id.*

Nominal US equity market returns of 3.7% to 5.7% range over the next decade.[54]

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

As another point of reference, Charles Schwab published an article on May 3, 2021 titled "Why Market Returns May be Lower and Global Diversification More Important in the Future."[55] This article noted that "[m]arket returns on stocks and bonds over the next decade are expected to fall short of historical averages"[56] and that Schwab's "estimates show that, over the next 10 years, stocks and bonds will likely fall short of their historical returns from 1970 to December 2020. The estimated annual expected return for U.S. large-capitalization stocks from January 2021 to December 2030 is 6.6%, for example, compared with an annualized return

---

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

of 10.8% during the historical period."[57] This article also includes a chart that shows the overall market return, and overall market premium, for US large capitalization stocks are expected to be 6.6% and 4.5%, respectively, and that the same figures for US small capitalization stocks are expected to be 7.1% and 5.0%, respectively.[58]

I also note that in 2018, and prior to the COVID-19 pandemic, Dominion University finance professors published equity risk premium estimates that stated the expected average risk premium exhibited by a survey of U.S. Chief Financial Officers around the country was expected to be 4.42%.[59] The study stated the following:

> During the past 18 years, we have collected almost 25,000 responses to the survey. Panel A of Table 1 presents the date that the survey window opened, the number of responses for each survey, the 10-year Treasury bond rate, as well as the average and median expected excess returns. There is relatively little time variation in the risk the historical risk premiums contained in Table 1. The current premium, 4.42%, is above the historical average of 3.64%. The December 2017 survey shows that the expected annual S&P 500 return is 6.79% (=4.42%+2.37%) which is slightly below the overall average of 7.11%.[60]

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

---

[57] *Id.* (emphasis added).
[58] *Id.*
[59] John R. Graham and Campbell R Harvey, *The Equity Risk Premium in 2018*, Duke University (Mar. 28, 2018), at 3–4.
[60] *Id*. (emphasis added).

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

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

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

Q. WHAT WERE YOUR CAPM RESULTS?

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

As shown above in Chart 1, I provided the change in the 30-year U.S. Treasury bonds over the past year. During this time period, the minimum yield was 1.40%, the maximum yield was 2.45%, and the average yield was 1.96. **Chart 1** above provides further details on these bond yields.

The average Beta for the comparable company proxy group is 0.90 which, when multiplied by the risk premium range of 4.25% to 6.25%, produces a Beta-adjusted risk premium of 3.83% to 5.63%. The 30-year U.S. Treasury yield ("Rf") range of 1.40% to 2.45% is next added to the Beta-adjusted risk premium range of 3.83% to 5.63% to arrive at the comparable company proxy group CAPM result range of 5.23% (3.83% + 1.40% = 5.23%) to 8.1% (5.63% + 2.45% = 8.08%, rounded to 8.1%).

Additionally, the Beta for PSNC's parent company Dominion is 0.85 which, when multiplied by the risk premium range of 4.25% to 6.25%, produces a Beta-adjusted risk premium of 3.61% to 5.31%. The 30-year US Treasury yield (Rf) range of 1.40% to 2.45% is next added to the Beta-adjusted risk premium range of 3.61% to 5.31% to arrive at Dominion's CAPM result range of 5.0% (3.61% + 1.40% = 5.01%, rounded to 5.0%) to 7.8% (5.31% + 2.45% = 7.76%, rounded to 7.8%).

Based on this range of results for the CAPM, as found in **Exhibit KWO-7**, I find the proper ROE derived from the CAPM is in the range of 6.00% to 8.00%. The low-end (6.00%) of this range is above the average of the comparable company proxy group CAPM results using the 4.25% equity risk premium (5.2%) and is also above the average of Dominion's results using the 4.25% equity risk premium (5.5%) as well. The high end (8.00%) of the range is positioned at the high end of the average of the comparable company proxy group CAPM results using the 6.25% equity risk premium (8.1%) and is above the high end of the Dominion results (7.8%) as well.

D. Return on Equity ("ROE") Summary

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

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

Table 9: ROE Method Results

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

Q. WHAT IS YOUR ROE RECOMMENDATION IN THIS PROCEEDING?

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

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

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

Table 10: CUCA Recommended Overall Rate of Return

CUCA's Overall Recommendation			
Component	Ratio (%)	Cost Rate (%)	Weighted Cost Rate (%)
Long-Term Debt	48.53%	4.43%	2.15%
Short-Term Debt	1.47%	0.24%	0.00%
Common Equity	50.00%	9.00%	4.50%
Total Capitalization	**100.00%**		**6.65%**

VIII. REVIEW OF COST OF EQUITY ANALYSIS OF WITNESS NELSON

Q. HOW DID MS. NELSON DEVELOP HER LIST OF COMPARABLE COMPANIES?

A. Ms. Nelson developed her comparable company proxy "Gas Group" by first determining which gas utilities were followed by *The Value Line Investment Survey*.[61] However, as previously referenced earlier within my testimony, of the ten Natural Gas Utilities followed by *Value Line*, Ms. Nelson opted to remove UGI Corporation ("UGI"), NiSource, and Chesapeake Utilities ("Chesapeake") from her comparable company proxy group at the conclusion of her screening process, leaving her comparable company proxy group comprised of seven companies.

In such industries where there are a higher number of such comparable companies (such as the electric utility industry), I have

[61] Witness Nelson Direct Testimony, page 20.

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

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

A. <u>Review of Ms. Nelson's DCF Analysis</u>

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR APPLICATION OF THE DCF MODEL AND MS. NELSON'S APPLICATION OF THE DCF?

A. My DCF analysis in this proceeding produced a range from 7.50% to 9.50% where I used a wide range of forecasted and historical EPS, DPS, and BPS growth rates. Ms. Nelson's application of the DCF Models (both Annual DCF and Quarterly DCF) ranged from 9.47% to 11.14%. and Ms. Nelson only utilized forecasted EPS growth rates in her DCF analysis.[62]

Q. HOW DID MS. NELSON PERFORM THE DCF CALCULATIONS FOR HER COMPARABLE UTILITY GROUP?

A. As I mentioned previously, a DCF calculation is largely made up of two inputs, an average dividend yield and an average growth rate. To begin her DCF calculation, Ms. Nelson determined the dividend yield across her comparable group within Nelson Direct Exhibit 2.. She took the dividend at January 29, 2021 and then divided this dividend by the average closing price of the last 30, 60, and 90 trading days ending February 26, 2021 for each company.[63] Ms. Nelson then performed an adjustment to these historical dividend yields by factoring in a growth rate component equal to one-half the conclusion of the growth rate (*i.e.,* Company's Historical Dividend Yield x (1 + (½ x Company's Average Projected EPS Growth Rate)).

In contrast, I utilized forecasted annual dividend yield for each company within my proxy group across three separate time periods (*i.e.,* 13-weeks, 4-weeks, and 1-week). While Ms. Nelson' dividend yield approach

---

[62] Witness Nelson, page. 25.
[63] Witness Nelson, Nelson Direct Exhibit 2.

afforded her the use of higher dividend yield averages to use within her DCF analysis, the primary reason that her DCF result approximates the high end of my DCF result range was due to her decision to only rely upon forecasted EPS growth rates.

Q. DO YOU AGREE WITH MS. NELSON' EXCLUSIVE USE OF FORECASTED GROWTH RATES IN HER DCF MODEL AND OMISSION OF HISTORICAL GROWTH RATES?

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

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

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

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

> [I]t is commonly suggested that one group of informed participants, security analysts, may have some ability to predict growth. The dispersion in analysts' forecasts indicates their willingness to distinguish boldly between high- and low-growth prospects. IBES long-term growth estimates are associated with realized growth in the immediate short-term future. Over long horizons, however, there is <u>little forecastability in earnings, and analysts' estimates tend to be overly optimistic</u>.[64]

Additionally, an article written by Professors Rocco Ciciretti, Gerald P. Dwyer, and Iftekhar Hasan, "Investment Analysts' Forecasts of Earnings," noted that "there is strong support for average and median earnings forecasts being higher than actual earnings a year before the earnings announcement"[65]; and an article published by McKinsey & Company,

---

[64] K. Chan, L., Karceski, J., & Lakonishok, J., *The Level and Persistence of Growth Rates*, Journal of Finance (2003), at 683 (emphasis added).
[65] Ciciretti, R., P. Dwyer, G., & Iftekhar, H., *Investment Analysts' Forecasts of Earnings*, Federal Reserve Bank of St. Louis Review (2009), at 545.

Strategy & Corporate Finance entitled "Equity analysts: Still too bullish" noted that "[a]nalysts, we found, were typically overoptimistic, slow to revise their earnings forecasts to reflect new economic conditions, and prone to making increasingly inaccurate forecasts when economic growth declined."[66]

I recognize that there are other academic articles and journals that support the opposite viewpoint. However, given the fact that this remains a debated topic within the financial community, it is appropriate to include EPS, DPS, and BPS from both an historical and forecasted perspective, as well as plowback growth rates, and the associated DCF results for each, within my analysis. In contrast, placing undue reliance upon forecasted EPS growth rates produces unrealistically high returns on equity numbers that cannot be sustained indefinitely.

Q. WOULD MS. NELSON'S DCF ANALYSIS HAVE RETURNED A LOWER RESULT HAD SHE UTILIZED BOTH HISTORICAL AND FORECASTED GROWTH RATES FROM A VARIETY OF METRICS AS OPPOSED TO SIMPLY USING HISTORICAL EPS GROWTH RATES?

---

[66] Goedhart, M., Raj, R., & Saxena, A., *Equity analysts: Still too bullish*, McKinsey & Company Strategy & Corporate Finance (2010).

A. Yes. As shown in Ms. Nelson's, Direct Exhibit 2, Ms. Nelson' growth rates ranged from 1.50% to 10.50% for *Value Line*, 5.00% to 7.50% for *Zack's*, 3.10% to 7.10% for Zacks..

However, as shown within **Exhibit KWO-2**, the historical growth rates for my proxy group ranged from -3.0% to 10.0% and for Dominion Energy ranged from -5.0% to 12.0% and my forecasted growth rates for my proxy group ranged from 0.5% to 11.5% and for Dominion ranged from -1.5% to 12.0%. Clearly the forecasted growth rates relied upon by Ms. Nelson led her ultimate DCF result to approximate the absolute high end of my overall DCF result range.

B. <u>Review of Ms. Nelson' CAPM Analysis</u>

Q. WHAT ARE THE PRIMARY DIFFERENCES BETWEEN YOUR APPLICATION OF THE CAPM AND MS. NELSON'S APPLICATION OF THE CAPM?

A. My CAPM analysis in this proceeding produced a range from 6.00% to 8.00%. Ms. Nelson's CAPM analysis produced a range from 12.48% to 13.01%.[67] The primary differences between my application of the CAPM and Ms. Nelson's application of the CAPM are the following:

[67] Witness Nelson Direct, p. 39

- Ms. Nelson utilized certain data points for her forecasted market return that inflated the overall Market Risk Premium used within her CAPM analysis;[68] and
- Ms. Nelson employed the use of a Traditional CAPM and an Empirical CAPM, averaged the results of both, and then presented that value as her ultimate CAPM result.[69]

Q. PLEASE EXPLAIN HOW MS. NELSON APPLIED THE CAPM.

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

Q WHAT IS THE RISK-FREE RATE THAT MS. NELSON USES IN HER CAPM ANALYSIS?

A. In her direct testimony, Ms. Nelson cited a 1.97% current yield on the 30-years Treasury bond and a projected 30-year Treasury yield of 2.72%.[70]

---

[68] Witness Nelson Direct Exhibit 4.
[69] *Id.*
[70] Witness Nelson, p. 35, l. 10-12.

Q. DO YOU AGREE WITH MS. NELSON' FORECASTED RISK-FREE RATE?

A. I do not take issue with the risk-free rate range used by Ms. Nelson in this proceeding[71] As shown within **Exhibit KWO-7**, I have used the 30-year U.S. Treasury Bond Yield to approximate what I deem to be appropriate to use for the risk-free rate for application within the CAPM. This yield over the period from August 21, 2020 to August 20, 2021 ranged from 1.34% to 2.54%, with an average of 1.92%.

Q. DO YOU AGREE WITH MS. NELSON' BETAS USED WITHIN HER CAPM ANALYSIS?

A. I do not take issue with the Beta values used by Ms. Nelson in this proceeding.

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

A. Ms. Nelson utilized the DCF model for the S&P 500 companies using data from Bloomberg and Value Line.[72] Her results were 16.35% for Bloomberg and 14.34% for Value Line. [73] Ms. Nelson states she used the Value Line estimate of 14.34% in the CAPM.

---

[71] *Id.*
[72] Witness Nelson, p. 36, lines 16-17.
[73] Id, p. 37, lines 5-7

I urge the Commission to scrutinize Ms. Nelson's testimony in this proceeding. She wants this Commission to believe the stock market is going to produce long-term returns of 14.34% to 16.35% into the foreseeable future. All of us invest in assets frequently throughout our lives. We invest in homes, we invest in retirement accounts, we invest in normal portfolios, we invest in many other opportunities. I ask the Commission to ask his/her own personal financial advisor if he/she believes the market is going to produce total returns as high as 15% in the coming years. In addition, please read financial literature and watch shows such as Squawk Box, etc. to see what financial experts are truly expecting. I contend that the overall market return forecast of Ms. Nelson if 14.34% to 16.35% is grossly incorrect.

Q. HOW DOES MS. NELSON'S FORECASTED MARKET RETURN COMPARE TO FORECASTS FROM OTHER ANALYSTS?

A. As I indicated previously, well-known entities such as Morningstar and Vanguard forecasted market returns from -0.1% to 5.7% during January 2021.[74] Additionally, Charles Schwab published an article that included a chart that showed that the overall market return, and overall market premium, for U.S. large capitalization stocks are expected to be 6.6% and 4.5%, respectively, and that the same figures for U.S. small capitalization

---

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

stocks are expected to be 7.1% and 5.0%, respectively.[75] Ms. Nelson's Forecasted Market Return of 10.42% and Forecasted Market Premium of 8.11% (*i.e.,* 10.42% Market Risk Premium - 2.31% Risk-Free Rate), as referenced above are, to say the least, unrealistic.

Whether the comparison is to forecasts from current day analysts or to historical returns, Ms. Nelson's market return forecasts used within her CAPM analysis simply have no underlying fundamental support or reasoning.

Q. DID MS. NELSON ALSO USE ANOTHER CAPM COST OF CAPITAL MODEL?

A. Yes., Ms. Nelson also used the Empirical Capital Asset Pricing Model ("ECAPM"). She explains the ECAPM by stating:

> The ECAPM addresses the tendency of the CAPM to under-estimate the Cost of Equity for companies, such as regulated utilities, with low Beta coefficients. As discussed below, the ECAPM recognizes the results of academic research indicating that the risk-return relationship is different (in essence, flatter) than estimated by the CAPM, and that the CAPM under-estimates the alpha, or the constant return term.

The ECAPM pricing model makes use of a weighted Risk Premium, with the Overall Market Risk Premium weighted by a factor of 25%, and a company-specific Beta-adjusted Risk Premium based on the stocks' relative

[75] https://www.schwab.com/resource-center/insights/content/why-market-returns-may-be-lower-in-the-future

volatility being weighted by 75%. Essentially, this ECAPM method is utilized when an analyst feels as though the weighted risk premium will help to correct for returns produced that were too high or too low for stocks with low Betas (*i.e.,* those stocks that are deemed to be less risky than the overall market) or high Betas (*i.e.,* those stocks that are deemed to be more risky than the overall market), respectively.

C. <u>Review of Ms. Nelson's Risk Premium Method</u>

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

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

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

Q. PLEASE EXPLAIN MS. NELSON'S APPLICATION OF HER RISK-PREMIUM MODEL.

A. Ms. Nelson's Risk Premium model produced a range from 9.75% to 9.86%. Ms. Nelson determined the risk premium for utility applications were in the range of 7.89%, which is used with projected 30-year Treasury bonds, and 7.04%, which is used with current 30-year Treasury bonds.

It is important to keep in mind what Ms. Nelson is herein advocating. She says the risk premium for a regulated utility with a monopoly service territory is more than DOUBLE the overall historical market return as shown in **Table 8** above. Again, Ms. Nelson's comments simply do not make sense.

D. <u>Other Adjustments Employed by Ms. Nelson</u>

Q. DO YOU AGREE WITH MS. NELSON THAT THE ALLOWED ROE FOR PSNC SHOULD BE ELEVATED TO ACCOUNT FOR HER PERCEIVED SIZE DIFFERENCE?

A. No. PSNC is owned by Dominion Resources, which is a massive utility holding company. Investors cannot buy common equity in PSNC. When investors buy long-term debt of PSNC, they realize that the ultimate holder of that debt is Dominion as the utility holding company will not allow anything negative on a financial basis to happen at a subsidiary. Hence, no size adjustment consideration is warranted.

IX. COST OF SERVICE STUDY AND RATE DESIGN

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

A. PSNC retained the services of Witness John Taylor for the development of its cost of service study and its proposed rate design in this case.

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

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

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

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

Q. HOW DID MR. TAYLOR ALLOCATE DISTRIBUTION MAINS WITHIN HER ACOSS?

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Customer Class	Peak & Average	Peak Day
Residential	5.90%	5.59%
Small Gen. Svc.	6.35%	6.15%
Medium Gen Svc.	10.21%	10.25%
Large Firm Svc	2.04%	3.06%
Large Int. Svc.	0.43%	1.39%

As can be seen in the table above, there is not much of a difference in the class rates per the two COSS methods.

Q. WHAT ARE MR. TAYLOR'S PROPOSED CUSTOMER CLASS RATE INCREASES?

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

Table 12: PSNC Proposed Class Rate Increases

Customer Class	PSNC Proposed Rate Hikes
Residential	9.15%
Small Gen. Svc.	9.15%
Medium Gen Svc.	4.57%
Large Firm Svc	18.29%
Large Int. Svc.	18.29%

On pages 20 and 21 of his prefiled direct testimony, Mr. Taylor provides several reasons for his recommended rate design. One aspect he apparently did not consider, or at least did not mention in his testimony, is rate shock. Proposed rate hikes of 18.29% is rate shock to PSNC's large firm customers and its large interruptible customers. If these rate hikes are accepted by this Commission, manufacturers may be forced to close and, if these closures occur, rates for the remaining customers will increase as the fixed costs will need to be spread to all remaining customer classes.

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

A. Yes, I am.

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

A. The basis of my rate design is the assumption that the sum of all my rate recommendations must allow PSNC to earn my recommended overall cost of capital of 6.52%. I then made a second assumption that no customer class could sustain a rate increase or decrease of more than 10%. My recommended rate change per customer class and the resulting class rates of return are found in **Table 13** below.

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

Customer Class	CUCA Rec Rate Increase (%)
Residential	6.83%
Small GS - Rate 102	6.24%
Medium GS - Rate 152	3.00%
Large General Service	7.85%
Large GS Trans. - Rate 113	7.62%

In the above rate design, I attempted to balance the interests of all customer classes without allowing any one particular class to sustain excessive rate hikes while other classes enjoyed significant rate cuts. My testimony in this case is compatible with the testimony I recently filed in the Piedmont case. While I do represent manufacturers before this Commission, CUCA and I also want to do what is right. PSNC's rate design is not correct in that Mr. Taylor paid no attention to rate shock that, if adopted by this Commission will run manufacturers, their jobs, and their tax base out of North Carolina.

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

A. Yes, I used the SWPA ACOSS in the development of my recommended rate design. The reason is that use of the Peak Day ACOSS would not have altered my recommended rate design in any meaningful way.

X. <u>SUMMARY</u>

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

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

- The proper capital structure to use in this proceeding is 50.00% common equity, 48.52% long-term debt; and 1.48% short-term debt.
- The Company's long-term debt cost rate should be set at 4.43% and its short-term debt rate should be set at 0.25%
- The Company's allowed ROE should be set at 9.00%.
- The overall rate of return that PSNC should be allowed to earn in this proceeding is 6.65%.
- The Company's requested capital structure and ROE are, both, unreasonable for ratemaking purposes.
- The recommended rate changes per customer class are as follows:
    - Residential – 6.83% increase
    - Small Gen. Svc – 6.24% decrease
    - Med. Gen Svc. – 3.00% decrease
    - Large Gen. Svc – Firm Sales – 7.85% increase
    - Large Gen Svc. –Interruptible – 7.62% increase

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

Certificate of Service

I hereby certify that a copy of the foregoing Direct Testimony of Kevin O'Donnell (with exhibits) has been served this day upon the parties of record in this proceeding by electronic mail.

This the 23rd day of September, 2021.

BROOKS, PIERCE, McLENDON,
HUMPHREY & LEONARD, LLP

/s/ Craig D. Schauer

MR. SCHAUER: Thank you. And, Commissioner, he also -- Mr. O'Donnell also had seven (7) exhibits associated with his direct testimony, if those could be identified as marked and also be received into evidence, that would be appreciated as well.

COMMISSIONER BROWN-BLAND: And that includes his Appendix A as well?

MR. SCHAUER: Yes. That's correct.

COMMISSIONER BROWN-BLAND: All right. Without objection, that motion will be allowed and the exhibits and Appendix A are received into evidence.

(O'Donnell Direct Exhibits 1 through 7 and Appendix A were marked for identification and admitted into evidence.)

MR. SCHAUER: Thank you.

COMMISSIONER BROWN-BLAND: And they are identified as they were marked when prefiled.

All right. That concludes the evidence for CUCA. Evergreen?

MS. CRESS: Thank you, Commissioner Brown-Bland. At this time, Evergreen Packaging moves that its witness Collins' prefiled direct testimony filed in these dockets on September 23rd, 2021, consisting of 22 pages, be admitted and copied into the record as if given orally from the stand. And, additionally, we move that our witness Collins direct exhibits premarked as BCC 1 through BCC 6 be admitted and entered into the record. Thank you.

COMMISSIONER BROWN-BLAND: All right. I'm going to lean on you, Ms. Cress, because my -- my identifying info didn't -- does not match yours. I had 17 pages, eight (8) exhibits. So as long as you're comfortable with what you stated is correct, we will go with that.

MS. CRESS: I think we're -- the discrepancy is probably just witness Collins' qualifications at the end of his testimony, which brings us to the 22-page count, which includes the cover sheet.

COMMISSIONER BROWN-BLAND: All right. And the exhibits, you said there are six (6)?

MS. CRESS: Yes, ma'am.

COMMISSIONER BROWN-BLAND: So that motion on behalf of Evergreen is allowed and the direct testimony will be received into evidence and treated as if given orally from the witness stand. The exhibits will be received into evidence and identified as they were marked when prefiled.

MS. CRESS: Thank you, Commissioner.

(Collins Direct Exhibits 1 through 6 were marked for identification and received into evidence.)

(Whereupon, the prefiled direct testimony of Brian C. Collins was copied into the record as if given from the stand.)

STATE OF NORTH CAROLINA

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of	)	
	)	
Application of Public Service Company of North Carolina, Inc. for a General Increase in Rates and Charges	)	**DOCKET NO. G-5, SUB 632**

Direct Testimony and Exhibits of

Brian C. Collins

On behalf of

Evergreen Packaging, LLC, a subsidiary of Pactiv Evergreen, Inc.

September 23, 2021

BRUBAKER & ASSOCIATES, INC.

Project 11167

STATE OF NORTH CAROLINA

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

In the Matter of

Application of Public Service Company of North Carolina, Inc. for a General Increase in Rates and Charges

DOCKET NO. G-5, SUB 632

<u>Direct Testimony of Brian C. Collins</u>

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION?

A I am a consultant in the field of public utility regulation and a principal with Brubaker & Associates, Inc., a firm specializing in energy, economic and regulatory consulting. Our firm and its predecessor firms have consulted in this field since 1937 and have participated in more than 1,000 proceedings in 40 states and several Canadian provinces. We have experience with more than 350 utilities, including many electric utilities, gas pipelines, and local distribution companies ("LDCs").

Q PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A This information is included in Appendix A to my testimony.

Q ON WHOSE BEHALF ARE YOU TESTIFYING IN THIS PROCEEDING?

A I am testifying on behalf of Evergreen Packaging, LLC, a subsidiary of Pactiv Evergreen, Inc. ("Evergreen"). Evergreen is a major contributor to the economy for this service territory in North Carolina and the large increase as proposed by Public Service Company of North Carolina, Inc. ("PSNC") is inappropriate and unwarranted.

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

A No. However, I have been involved in many gas and electric proceedings in other jurisdictions over the last 20 years and have presented testimony in many of those proceedings.

Q WHAT IS THE SUBJECT MATTER OF YOUR TESTIMONY?

A My testimony is directed toward PSNC's gas cost of service study, the allocation of any allowed rate increase to customer classes, and rate design. I have examined the testimony and exhibits presented by PSNC in this (and its last general rate case) proceeding with respect to cost of service, revenue allocation, and rate design, and I will comment on the propriety of these proposals, and make certain comments and recommendations. In addition, I comment on the federal and state tax credits due to PSNC customers. I also address PSNC's proposed return on equity ("ROE") and make recommendations in this regard.

Q DOES THE FACT THAT YOU DO NOT ADDRESS EVERY ISSUE RAISED IN PSNC'S TESTIMONY MEAN THAT YOU AGREE WITH PSNC'S TESTIMONY ON THOSE ISSUES?

A No. It merely reflects that I did not choose to address all of those issues. It should not be read as an endorsement of, or an agreement with, PSNC's position on such issues. In order to make my presentation consistent with the revenue levels requested by PSNC, I have used the revenues produced by PSNC's proposed rates. Use of these numbers should not be interpreted as an endorsement of them for purposes of determining the total dollar amount of any rate increase authorized for PSNC.

Summary of Conclusions and Recommendations

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

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

1. PSNC's gas rates should be based on the cost of providing service to each customer class. They are not.

2. PSNC's gas cost of service study is a form of an arbitrary peak and average method and allocates excessive cost to high load factor customers on a throughput weighted allocation as compared to a peak demand cost of service study. PSNC's proposed 50% throughput / 50% design day peak cost of service study is unsupported by engineering studies and inconsistent with the design of the PSNC gas delivery system.

3. PSNC's gas delivery system is designed to meet design day peak demand.

4. PSNC has provided a design day peak cost of service study, which is reflective of cost causation and should be used as the basis for revenue distribution and rate design.

5. Mr. John D. Taylor, managing partner of Atrium Economics, presents the cost of service for PSNC. Atrium Economics recently issued a 2021 cost of service review for Centra Gas Manitoba Inc., in which it soundly rejects the peak and average method previously used by the utility and recommends the design day peak method as reflective of cost causation for a local distribution company.

6. PSNC proposes a distribution of the increase based on a 20% rate of return band receiving an average increase, with 50% of the average increase allocated to classes above the 20% band, and 200% of the average increase allocated to classes below the 20% band. This method is overly harsh, unreasonable, and unjust to classes below the 20% band. No class should receive an increase more than a maximum 150% of the average increase as an upper limit.

7. The results of the design day peak study, which should be used as the basis for rate design, show that most classes are close to cost of service with no class receiving the harsh increase currently proposed by PSNC.

8. PSNC's proposed rate design for Rate 175 should be rejected. It is not cost based, not reflective of any cost study for the various rate blocks and significantly punishes high usage customers.

9. Rather, Rate 175 should be refined to:

    a. Contain a basic facilities charge reflective of cost;

    b. Collect fixed charges in the initial blocks; and

    c. Decrease charges in higher usage blocks to be reflective of only variable costs.

10. PSNC has requested an excessive return on equity of 10.25%. Based on a review of capital cost reductions that have occurred since PSNC's last general rate case, it is recommended that the allowed ROE not exceed 9.55% in this proceeding.

Cost of Service and Rate Design Principles

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

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

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

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

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

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

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

Q PLEASE DISCUSS THE STABILITY CONSIDERATION.

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

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

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

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

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

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

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

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

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

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

PSNC's Gas Cost of Service Study

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

A Yes. PSNC witness John D. Taylor submitted 2020 cost of service studies based on present rate-adjusted results and under PSNC's proposed rates. I will focus on the present rates adjusted for test year study.

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

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

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

Q HAS MR. TAYLOR'S FIRM RECENTLY ISSUED A REPORT REJECTING THE USE OF THE PEAK AND AVERAGE METHOD FOR ALLOCATING THE COST OF MAINS TO CUSTOMER CLASSES?

A Yes. Mr. Taylor, managing partner of Atrium Economics, presents the cost of service for PSNC based on the peak and average method. However, his firm, Atrium Economics, recently issued a 2021 cost of service review for Centra Gas Manitoba Inc., which soundly rejects the peak and average method previously used by the utility and recommends the design day peak method as reflective of cost causation for a local distribution company.

Q WHAT DOES THE ATRIUM REPORT RECOMMEND?

A The Atrium report, which is attached as Exhibit BCC-6, recommends that the peak and average method is not consistent with cost causation and penalizes high load factor customers and should be replaced with a design day peak method. The Atrium report states:

> "*Replace Allocation of Transmission and Distribution Plant Using the Peak & Average Allocation Method with a Coincident Peak Day Allocation Method.* Atrium maintains that transmission and distribution plant is a function of the cumulative peak day demands of those customers served by those pipeline infrastructure investments and recommends the use of a Coincident Peak Day allocation of transmission mains and the demand component of distribution mains."

* * *

"The P&A method penalizes high load factor customer classes in the following manner. Economies of scale are always recognized when a gas utility sizes its distribution mains to satisfy peak capacity requirements of its customers. The concept of economies of scale drives overall costs incurred by a gas utility for its gas distribution mains and these economies of scale are reflected in Centra's embedded costs of distribution mains. However, economies of scale affect the sizing of distribution mains- but not the allocation of their resulting costs. The economies of scale enjoyed by a gas utility are created by the interaction of the capacity requirements of all its customers. Centra does not plan for the changing needs of its distribution system by examining the capacity requirements of any one customer class or by conducting capacity planning by first disaggregating its capacity needs into "average demand requirements" and "peak demand requirements." Rather, it examines its capacity needs in the aggregate based on the peak hour demands on its design day for all of its customers or for the group of customers added to the existing distribution system at any point in time.

The fallacy in the P&A allocation method becomes clear for a customer class that exhibits a high load factor. According to the P&A allocation method, this class should not receive any economies of scale benefits because the class' average demand is high relative to its peak demand. Yet, the engineering reality is that this class should receive economies of scale benefits just as any other class to the extent the capacity requirements of this class at the time these customers were connected to the gas utility's distribution grid created economies of scale in the costs of expanding the grid to accommodate them.

From a purely cost causation perspective, transmission and distribution main investments are simply not a function of throughput. Instead, they are a function of the cumulative peak day demand of those customers served by those transmission and distribution main investments. Based on today's rate design structures, changes in throughput will affect the recovery of the utility's investment in distribution mains but that is much different from concluding that there is a cost causation relationship between the investment and throughput. In fact, there is no such cost relationship."

* * *

"A Local Distribution Company's (LDC's) gas system is designed, and consequently capacity related costs are incurred, to meet design day demand. In contrast, these costs are not incurred on the basis of an average of peak demands."

Q DO YOU AGREE WITH THE ATRIUM REPORT REGARDING THE REJECTION OF THE PEAK AND AVERAGE COST ALLOCATION METHOD AND THE RECOMMENDATION TO USE THE DESIGN DAY PEAK METHOD?

A Yes. The Atrium report is correct in that regard.

Q WHAT IS THE BASIS FOR PSNC'S SYSTEM DESIGN?

A PSNC states:

> "PSNC's system is designed to serve firm customers on a design day while maintaining target minimum pressures within the system (typically 30 PSIG in a 60 PSIG system)."
>
> (PSNC's response to Evergreen's Data Request No. 2, August 6, 2021, Response 2-3)

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

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

> Demand or capacity costs vary with the size of plant and equipment. They are related to maximum system requirements which the system is designed to serve during short intervals and do not directly vary with the number of customers **or their annual usage**. Included in these costs are: the capital costs associated with production, transmission and storage plant and their related expenses; the demand cost of gas; and most of the capital costs and expenses associated with that part of the distribution plant not allocated to customer costs, such as the costs associated with distribution mains in excess of the minimum size. (NARUC Manual, Gas Distribution Rate Design, June 1989, pp. 23-24; emphasis added)

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

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

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

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

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

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

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

A Yes. PSNC performed a peak demand study in response to discovery from Evergreen. In that study, peak demand data is used to allocate fixed demand-related delivery costs in place of the peak and average method. The results of the peak demand study are shown on Exhibit BCC-1.

The peak demand study is a more correct representation of the actual cost of service associated with serving the various customer classes and should be used as the basis for the allocation of any allowed increase in this proceeding. The peak demand shows that certain subsidies are larger and make any corrective distribution of the requested increase even more difficult to manage in this case.

Q HAVE YOU EXAMINED THE CLASS RATES OF RETURN, INDEXES AND SUBSIDIES BASED ON THE DESIGN DAY PEAK COST OF SERVICE?

A Yes. Exhibit BCC-1 shows the results of the design day cost of service, and also indexes and subsidies at both current rates and rates based on the recommended distribution of the increase Residential, Small General Service and Large Quantity Interruptible Service classes are close to cost of service. The Medium General and Large Quantity General service classes are significantly above cost of service.

Q WHAT IS THE BASIS FOR YOUR RECOMMENDED DISTRIBUTION OF THE INCREASE?

A I basically used the parameters recommended by PSNC. Classes close to cost of service received an approximate average increase; classes above cost of service receive approximately 50% of the average increase. Exhibit BCC-2 shows the recommended distribution of the increase based on total revenue and Exhibit BCC-3 shows the recommended distribution of the increase based on margin or distribution revenue.

Q HAVE YOU REVIEWED PSNC'S PROPOSED RATE DESIGN FOR RATE 175?

A Yes. PSNC's proposed rate design is shown on Exhibit BCC-4. PSNC is proposing significant increases to the higher usage blocks, which is inappropriate and would result in harsh, unreasonable, and unwarranted impacts or rate shock to higher usage customers. A declining block rate structure should be designed to collect fixed costs in the initial usage blocks and, once fixed costs are recovered, the higher usage blocks should only be recovering variable costs. To the extent the Commission approves a lower increase than the $53 million requested, I recommend that the higher usage blocks be lowered to reflect only variable costs.

Q HAS PSNC PERFORMED ANY COST STUDIES REGARDING THE SIZE OR ADEQUACY OF THE RATE BLOCKS IN RATE 175 ON THE CHARGES FOR THE VARIOUS RATE BLOCKS?

A No. In response to Evergreen's Data Request No. 1, PSNC stated the following:

> "The proposal presented in this case is for no changes to the basic facility charge and for the proposed revenue increase to be recovered through an equal volumetric increase to all volumetric blocks rates. Please see the Direct Testimony of John D. Taylor at page 24. This proposal required no analysis or separate study regarding the charges by usage block, for summer and winter periods, or for sales and transportation rates."

(PSNC's Response to Evergreen's DR 01-24; July 19, 2021).

Q IS THE DESIGN OF RATE 175 AN IMPACT ISSUE FROM PSNC'S MOST RECENT RATE CASE?

A Yes. Rate Design in Docket No. G-5, Sub 565 was an impact issue and addressed in the stipulation as follows:

> "The rate schedules and steps have not changed since the last rate case in 2016. In that case (Docket No. G-5 Sub 565), the Commission approved the rate design agreed to in Paragraph 5.E., which provided:
>
>> Rate Design. The Stipulating Parties are still continuing to work on rate design issues since the revenue requirement increase has not yet been determined. Notwithstanding the pending determination of the revenue requirement, the Stipulating Parties agree in principle that after a determination of the revenue requirement, each energy charge for Rate Schedule 145 and Rate Schedule 150 will be increased by no more than 3.25% and each existing energy charge for Rate Schedule 175 and Rate Schedule 180 will be increased by no more than 2.25%. The Stipulating Parties have agreed to an additional usage tier for Rate Schedule 175, as shown on Public Staff witness Jan Larsen's Amended Exhibit C, page 2 of 2. The Stipulating Parties agree that this additional usage tier will not result in any revenue shifting between any rate classes."

Q HAVE YOU DEVELOPED A RECOMMENDED RATE STRUCTURE FOR RATE 175?

A Yes. This is shown on Exhibit BCC-5. I have used an across-the-board approach to increase the rate blocks by approximately 9.9%. The recommended rate design is fair and reasonable to the customers taking service from Rate 175.

Since PSNC's large usage rates do not contain demand charges, the initial blocks should provide for fixed cost recovery in a similar manner to a demand charge that would provide for fixed cost recovery. The higher usage blocks should have relatively lower charges to reflect variable delivery costs similar to an energy charge for a tariff which contains a demand charge. Of course, the BFC should recover customer costs.

My recommended rate design, as shown in Exhibit BCC-5, follows this cost-based approach.

Return on Equity

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

A No. PSNC's requested ROE of 10.25% is excessive and should be rejected. The Company's current authorized ROE is 9.70%, which was authorized by approving a stipulation in the Commission's Final Order in Docket No. G-5, Sub 565, issued on October 28, 2016.

Every quarter, Regulatory Research Associates, an affiliate of SNL Financial, updates its *Major Rate Case Decisions* report that covers electric and natural gas utility rate case outcomes. Specifically, this report tracks the authorized ROEs resulting from utility rate cases around the country. The most recent report has been updated through June 30, 2021 and shows that the national average authorized ROE for gas utilities for the 12 months ending June 30, 2021 was 9.55%. This is 15 basis points below PSNC's currently authorized ROE. The Commission also should consider the IMR, and any other mechanisms which provide PSNC with additional cost recovery outside of a base rate case in setting a reasonable ROE.

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

Excess Deferred Income Taxes

Q DO YOU HAVE ANY COMMENTS ON THE COMPANY'S PROPOSAL TO FLOW THROUGH THE BENEFITS OF THE FEDERAL TAX CUTS AND JOBS ACT OF 2017

("TCJA") TO CUSTOMERS AS DESCRIBED IN PSNC WITNESS JAMES A. SPAULDING'S DIRECT TESTIMONY?

A Yes. The Excess Deferred Income Taxes ("EDIT") should be returned to customers as quickly as possible. The EDIT should also appropriately be returned to customers in the same manner that customers paid the taxes to PSNC. This will result in an appropriate allocation of EDIT to customers.

Q DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A Yes, it does.

Qualifications of Brian C. Collins

Q PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A Brian C. Collins. My business address is 16690 Swingley Ridge Road, Suite 140, Chesterfield, MO 63017.

Q WHAT IS YOUR OCCUPATION AND BY WHOM ARE YOU EMPLOYED?

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

Q PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND WORK EXPERIENCE.

A I graduated from Southern Illinois University Carbondale with a Bachelor of Science degree in Electrical Engineering. I also graduated from the University of Illinois at Springfield with a Master of Business Administration degree. Prior to joining BAI, I was employed by the Illinois Commerce Commission and City Water Light & Power ("CWLP") in Springfield, Illinois.

My responsibilities at the Illinois Commerce Commission included the review of the prudence of utilities' fuel costs in fuel adjustment reconciliation cases before the Commission as well as the review of utilities' requests for certificates of public convenience and necessity for new electric transmission lines. My responsibilities at CWLP included generation and transmission system planning. While at CWLP, I completed several thermal and voltage studies in support of CWLP's operating and planning decisions. I also performed duties for CWLP's Operations Department, including calculating CWLP's monthly cost of production. I also determined CWLP's allocation of wholesale purchased power costs to retail and wholesale customers for use in the monthly fuel adjustment.

In June 2001, I joined BAI as a Consultant. Since that time, I have participated in the analysis of various utility rate and other matters in several states and before the Federal Energy Regulatory Commission ("FERC"). I have filed or presented testimony before the Arkansas Public Service Commission, the California Public Utilities Commission, the Delaware Public Service Commission, the Public Service Commission of the District of Columbia, the Florida Public Service Commission, the Georgia Public Service Commission, the Guam Public Utilities Commission, the Idaho Public Utilities Commission, the Illinois Commerce Commission, the Indiana Utility Regulatory Commission, the Kentucky Public Service Commission, the Public Utilities Board of Manitoba, the Minnesota Public Utilities Commission, the Mississippi Public Service Commission, the Missouri Public Service Commission, the Montana Public Service Commission, the North Dakota Public Service Commission, the Public Utilities Commission of Ohio, the Oklahoma Corporation Commission, the Oregon Public Utility Commission, the Rhode Island Public Utilities Commission, the Public Service Commission of Utah, the Virginia State Corporation Commission, the Public Service Commission of Wisconsin, the Washington Utilities and Transportation Commission, and the Wyoming Public Service Commission. I have also assisted in the analysis of transmission line routes proposed in certificate of convenience and necessity proceedings before the Public Utility Commission of Texas.

In 2009, I completed the University of Wisconsin – Madison High Voltage Direct Current ("HVDC") Transmission Course for Planners that was sponsored by the Midwest Independent Transmission System Operator, Inc. ("MISO").

BAI was formed in April 1995. BAI and its predecessor firm has participated in more than 700 regulatory proceedings in forty states and Canada.

BAI provides consulting services in the economic, technical, accounting, and financial aspects of public utility rates and in the acquisition of utility and energy services through RFPs and negotiations, in both regulated and unregulated markets. Our clients include large industrial and institutional customers, some utilities and, on occasion, state regulatory agencies. We also prepare special studies and reports, forecasts, surveys and siting studies, and present seminars on utility-related issues.

In general, we are engaged in energy and regulatory consulting, economic analysis and contract negotiation. In addition to our main office in St. Louis, the firm also has branch offices in Phoenix, Arizona and Corpus Christi, Texas.

421377

COMMISSIONER BROWN-BLAND: All right. Thank you. And now we'll move to the Public Staff.

MS. HOLT: Do you want me to move our exhibits in first or call the witnesses?

COMMISSIONER BROWN-BLAND: It is normal we would just call the witnesses, but it's up to you.

MS. HOLT: Public Staff calls Ms. Sonja Johnson.

COMMISSIONER BROWN-BLAND: All right. Ms. Johnson, are you there?

MS. JOHNSON: Yes, ma'am.

(WHEREUPON,

SONJA R. JOHNSON,

having been duly affirmed, testified as follows:)

COMMISSIONER BROWN-BLAND: All right. Ms. Holt?

DIRECT EXAMINATION BY MS. HOLT:

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

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

Q. On September 23rd, 2021, did you prepare and cause to be filed in this docket testimony consisting of 23 pages, including cover sheet and appendix and one exhibit marked

Johnson Exhibit 1?
A. Yes, I did.
Q. Do you have any changes or corrections to your testimony or exhibit?
A. No, I do not.
Q. If I were to ask you the same questions today, would your answers be the same as in your pretrial testimony?
A. Yes, they would.
Q. Ms. Johnson, on October 5th, 2021, did you file a revised Johnson Exhibit 1?
A. Yes, I did.
Q. Do you have any additional changes or corrections to that exhibit?
A. No, I do not.
Q. On October 15th, 2021, did you prepare and cause to be filed four (4) pages of settlement testimony, including cover page, in support of the Stipulation, and one exhibit marked Settlement Exhibit 1?
A. Yes, I did.
Q. Do you have any changes or corrections to that settlement testimony or exhibit?
A. No, I do not.
MS. HOLT: Chair Brown-Bland, I move that Ms.

Johnson's direct testimony, consisting of 23 -- 23 pages be copied into the record as if given orally from the stand; that her settlement testimony, consisting of four (4) pages, be copied into the record as if given orally from the stand; and that Johnson Exhibit 1, Johnson Revised Exhibit 1 and Settlement Exhibit 1 be identified as marked when filed.

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

(Johnson Exhibit 1, Johnson Revised Exhibit 1 and Settlement Exhibit 1 were marked for identification.)

(Whereupon, the prefiled direct testimony and Appendix A and prefiled settlement testimony of Sonja R. Johnson were copied into the record as if given from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

DOCKET NO. G-5, SUB 632	)	
	)	
In the Matter of	)	
Application of Public Service Company	)	
of North Carolina, Inc., for a General	)	TESTIMONY OF
Increase in Rates and Charges	)	SONJA R. JOHNSON
	)	PUBLIC STAFF – NORTH
DOCKET NO. G-5, SUB 634	)	CAROLINA UTILITIES
	)	COMMISSION
In the Matter of	)	
Application for Approval to Modify	)	
Existing Conservation Programs and	)	
Implement New Conservation	)	
Programs	)	

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

TESTIMONY OF SONJA R. JOHNSON

ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 23, 2021

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

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

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS THE NATURE OF THE APPLICATION IN THIS RATE CASE?

A. Public Service Company of North Carolina, Inc. (PSNC or the Company), filed an application with the Commission on April 1, 2021, in Docket No. G-5, Sub 632, with a test period ended December 31, 2020, seeking authority for: (1) a general increase in and revisions to the rates and charges for customers served by the Company; (2) continuation of PSNC's Integrity Management Tracker (Rider E) mechanism; (3) continued deferral for certain incremental Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP) operations and maintenance (O&M) expenses; (4) utilization of new annual depreciation accrual rates for the Company's North Carolina and joint property assets based on a depreciation study conducted by Gannett Fleming Valuation and Rate Consultants, LLC, pursuant to Commission Rule R6-80; (5) revised and updated amortizations and recovery of certain regulatory assets accrued since the Company's last rate case in Docket No. G-5, Sub 565 (Sub 565); (6) utilization of the lead-lag study filed by PSNC in G-1 Item 26; (7) implementation of three rider mechanisms to allow PSNC to address certain liabilities arising from excess deferred income taxes (EDIT) associated with the Tax Cuts and Jobs Act and state income tax reductions; (8) approval to recover conservation program costs through deferred accounting treatment and a rider, Rider F; (9) implementation of the GreenTherm™ Renewable Natural Gas Program, a voluntary renewable energy program, (10) deferred accounting treatment and the implementation of Rider G; (11) approval to fund a research and development initiative to promote environmental sustainability; and (12) other updates and revisions to PSNC's rate schedules and service regulations.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's accounting and ratemaking adjustments and to incorporate the adjustments recommended by other Public Staff witnesses who work in the Accounting, Energy, and Economic Research Divisions. The Public Staff has made its adjustments based on its investigation of the revenue, expenses, and rate base presented by the Company in support of its original request for an annual revenue requirement increase of $53.1 million, as revised in the Company's June update filing to a request of approximately $49.7 million in this proceeding. In addition to this amount, the application also provides for decreases related to the proposed EDIT riders.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THIS RATE INCREASE APPLICATION.

A. My investigation included a review of the application, testimony, exhibits, and other data filed by the Company, an examination of the books and records for the test year, and a review of the Company's accounting, end-of-period, and after-period adjustments to test year revenue, expenses, and rate base. The Public Staff has also conducted extensive discovery in this matter, including the review of responses provided by the Company in response to Public Staff data requests, and participation in extensive virtual meetings with the Company.

Q. PLEASE BRIEFLY DESCRIBE THE PUBLIC STAFF'S PRESENTATION OF THE ISSUES IN THIS CASE.

A. Each Public Staff witness will present testimony and exhibits supporting his or her position and recommend any appropriate adjustments to the Company's proposed rate base and cost of service. My exhibits incorporate adjustments from other Public Staff witnesses, as well as the adjustments I recommend.

Q. PLEASE GIVE A MORE DETAILED DESCRIPTION OF THE ORGANIZATION OF YOUR EXHIBITS.

A. Schedule 1 of Johnson Exhibit I presents a reconciliation of the difference between the Company's requested revenue increase and the Public Staff's recommended decrease. In addition, the Public Staff has recommended decreases to the revenue requirement associated with the benefits resulting from EDIT associated with the federal Tax Cuts and Jobs Act of 2017 ("TCJA"), state income tax rate reductions addressed in Docket No. M-100, Sub 148, as well as deferred revenues associated with the over collection of taxes due to the federal tax change.

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

Schedule 3 presents a statement of net operating income for return under present rates as adjusted by the Public Staff. The Public Staff's adjustments are detailed on backup schedules.

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

Schedule 5 presents the calculation of the required decrease in operating revenue necessary to achieve the required net operating income. This revenue decrease is equal to the Public Staff's recommended revenue decrease shown on Schedule 1.

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

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

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

(2) The recommendation of Public Staff witness Patel regarding the following items:

(a) Cost of Gas;
(b) Other Operating Revenues;
(c) End-of-Period Revenues and Bills; and
(d) Research and Development Costs Adjustment.

(3) The recommendation of Public Staff witness McCullar regarding the Depreciation Rate Study, which included adjustments to certain deprecation rates.

(4) The recommendation of Public Staff witnesses Singer and Williams regarding EE Programs.

(45 The recommendations of Public Staff witness Feasel regarding the following items:

(a) Other Working Capital Updates;
(b) Deferred Transmission Integrity Pipeline Program Costs;
(c) Deferred Distribution Integrity Pipeline Program Costs; and
(d) Lead Lag Study.

(6) The recommendations of Public Staff witness Coleman regarding the following items:

(a) Board of Directors Expenses;
(b) Other Benefits; and
(c) Executive Compensation.

(7) The recommendations of Public Staff witness Perry regarding the following items:

(a) Excess Deferred Income Taxes (EDIT) Riders;
(b) Special Contract Adjustment;
(c) Durham Incident Adjustment;
(d) Integrity Management Rider Mechanism;
(e) EE Program Mechanism; and
(f) Green Therm Mechanism.

Q. PLEASE DESCRIBE YOUR RECOMMENDED ADJUSTMENTS.

A. The accounting and ratemaking adjustments that I will discuss relate to the following items:

(a) Plant in Service
(b) Accumulated Depreciation
(c) Accumulated Deferred Income Taxes (ADIT)
(d) Depreciation Expense
(e) Payroll
(f) Annual Incentive Plan and Long-Term Incentive Plans (AIP and LTIP)
(g) Pension and Other Post-Employment Benefits (OPEB) Expense
(h) Rate Case Expenses
(i) Regulatory Fee Expense
(j) Uncollectibles
(k) Advertising
(l) Lobbying
(m) Sponsorship and Dues
(n) Inflation Adjustment
(o) Customer Accounts Expense
(p) Non-utility Adjustment
(q) Interest on Customer Deposits
(r) Transmission O&M Expense Adjustment
(s) Service Company Adjustment
(t) Severance
(u) CNG Tax Credit

PLANT IN SERVICE AND ACCUMULATED DEPRECIATION

Q. PLEASE EXPLAIN HOW PLANT IN SERVICE, ACCUMULATED DEPRECIATION, AND ACCUMULATED DEFERRED INCOME TAXES HAVE BEEN REFLECTED IN YOUR EXHIBITS.

A. The Company filed a June Update, which reflected plant in service, accumulated depreciation, and accumulated deferred income taxes for actual charges recorded on the Company's books through June 30, 2021, the Public Staff's cutoff date for post-test year plant additions in this filing. I have included these June updates while also making an end-of-period depreciation adjustment to accumulated depreciation. Accumulated depreciation was adjusted for the difference between the annual depreciation expense per the Public Staff and the book depreciation expense for the 12-months ended June 30, 2021. Johnson Exhibit I Schedule 2-1 and all of its backup schedules reflect the Public Staff's calculation of and adjustments to plant in service, accumulated depreciation, and accumulated deferred income taxes.

DEPRECIATION EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEPRECIATION EXPENSE.

A. I made adjustments to (1) reflect various depreciation rate changes that were recommended by Public Staff witness McCullar, and (2) apply the rates to present and annualized amounts of depreciation expense based on the actual plant in service as of June 30, 2021. Johnson Exhibit I, Schedule 2-1 and all of its backup schedules reflect the Public Staff's calculation of and adjustments to depreciation expense.

PAYROLL EXPENSE

Q. PLEASE EXPLAIN YOUR PROPOSED PAYROLL EXPENSE ADJUSTMENT.

A. I updated the annualized payroll expense to a level that reflects pay rates and employees as of June 30, 2021, excluding temporary positions, and removed projected hires for employees that had not been hired as of June 30, 2021, which resulted in a reduction to the Company's pro forma level of payroll expense as reflected in Johnson Exhibit I, Schedule 3-1.

ANNUAL INCENTIVE PLAN (AIP)

Q. PLEASE EXPLAIN HOW THE COMPANY ADJUSTED THE INCENTIVE PLANS IN THIS CASE.

A. The Company made an adjustment to the incentive plan expenses in this case to reflect a 100% target payout of AIP expense for the Dominion Energy Services (DES) plans in effect for 2021 as opposed to payouts for the SCANA plans that were in effect during the test year.

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

A. DENC offers two incentive plans to its employees: the Annual Incentive Plan (AIP) and the Long-Term Incentive Plan (LTIP). The

AIP is offered to all non-union employees, including executives, who work 1,000 hours or more in a calendar year with acceptable performance. The LTIP is offered to employees at the executive level.

The AIP consists of goals set and approved by the Board of Directors (BOD) for a one-year term. Based on data request responses in this case, the AIP is funded based on consolidated operating earnings per share (EPS) with a minimum funding threshold and maximum payout.

The LTIP goals consist of Performance Shares, which are categorized between Return on Invested Capital (ROIC) and Total Shareholder Return (TSR), and Restricted Stock Units (RSU). Both offerings are set and approved by the BOD for a three-year period.

The Company's payout of AIP is based on the achievement of targets from minimum up to maximum levels. I have adjusted the allowable costs of AIP to exclude the incentive amounts that were based on the earnings metric, which is closely tied to the EPS, since the entire AIP is funded based upon a consolidated EPS. I have removed only the amounts related to all executive-level employees because these goals align with the shareholders' interests.

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

This treatment is consistent with incentive adjustments approved by the Commission in the last general rate cases of Duke Energy Carolinas, LLC (DEC) in Docket No. E-7, Sub 1214 (DEC Sub 1214 rate case), Duke Energy Progress, LLC (DEP), in Docket No. E-2, Sub 1219 (DEP Sub 1219 rate case), and Piedmont Natural Gas Company, Inc. (Piedmont) in Docket No. G-9, Sub 743. My adjustment is shown on Johnson Exhibit I, Schedule 3-3.

PENSION AND OPEB EXPENSE

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO THE COMPANY'S PENSION AND OPEB EXPENSE.

A. In the current rate case filing, the Company proposed an increase to its ongoing annual pension and OPEB expense based on the Company's 2021 projection. The Public Staff decreased the expense amounts by using an ongoing expense amount recorded on PSNC's books as of June 30, 2021, to compute its adjustment as shown on Johnson Exhibit I, Schedule 3-4.

RATE CASE EXPENSES

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO RATE CASE EXPENSES.

A. The Company has proposed that the estimate of rate case expenses for the current general rate case be amortized over a three-year period as compared to the five-year period originally filed for all other proposed amortization periods in this rate case filing.

The Public Staff has reviewed the actual invoices paid as of June 30, 2021, and the contracts related to the various consultants. I included an expense level that reflects an average of the difference between the Company's proposed amount and actual payments to determine the rate case expenses. My adjustment is shown on Johnson Exhibit 1, Schedule 3-5.

ADJUSTMENT TO REGULATORY FEE EXPENSE

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO THE NCUC REGULATORY FEE.

A. In its Order Decreasing Regulatory Fee Effective July 1, 2019 (issued June 18, 2019, in Docket No. M-100, Sub 142), the Commission ordered that the regulatory fee for noncompetitive jurisdictional revenues shall be set at 0.13%, effective July 1, 2019. The Public Staff made an adjustment to update the regulatory fee expense, as needed, for adjustments that impact revenues in this rate case.

UNCOLLECTIBLES EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO UNCOLLECTIBLES EXPENSES.

A. The Company made an adjustment to increase uncollectibles expenses for the test period ended December 31, 2020, by using a three-year average as compared to the last five years used by the Public Staff.

Pursuant to its Purchased Gas Adjustment procedures, PSNC recovers the gas cost portion of uncollectible account write-offs by charging the actual amounts to its Gas Cost Deferred Account. Therefore, the only portion of uncollectibles that should be included in O&M expenses in a rate case proceeding is the non-gas cost, also known as the “margin,” portion of customer bills.

My adjustment uses the NC charge-offs based on a five-year average of net NC charge-offs to sales and transportation revenues. Since the Company’s net charge-offs for 2020 were low, I recommend taking a five-year average since the other recent years reflect very high uncollectibles data due to cold weather events. Therefore, my adjustment resulted in a decrease in uncollectibles expense while reflecting an ongoing reasonable level as shown on Johnson Exhibit I, Schedule 3-7.

ADVERTISING EXPENSES

Q. PLEASE DESCRIBE YOUR ADJUSTMENT TO ADVERTISING EXPENSES.

A. I first requested a detailed listing of all advertising expenses and the associated ads for the test period. From this listing, I reviewed expenses from each advertising account and requested documentation to support the expenses. My adjustment, which is shown in Johnson Exhibit I, Schedule 3, is consistent with Commission Rule R12-13 and the Public Staff's position in all of PSNC's and Piedmont's previous general rate case proceedings.

LOBBYING EXPENSES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO LOBBYING EXPENSES.

A. I have adjusted O&M expenses to remove lobbying activities charged to PSNC during the test period consistent with the Public Staff's positions in the Sub 565 rate case, DEC Sub 1214 rate case, Piedmont Subs 743 and 781 rate cases, and the DEP Sub 1219 rate case. I adjusted lobbying expenses to remove O&M expenses associated with internal Government Affairs charges that were recorded above the line during the test period. I recommend that test year lobbying expenses be adjusted as shown in Johnson Exhibit I, Schedule 3-16.

SPONSORSHIPS AND DUES

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO SPONSORSHIPS AND DUES.

A. I have decreased O&M expenses to remove amounts charged for sponsorships and dues. These expenses should be disallowed because they were not incurred in order to provide natural gas service to PSNC's customers. My recommended adjustment is shown in Johnson Exhibit I, Schedule 3-6.

INFLATION

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR INFLATION.

A. The Company made an adjustment to test period costs to reflect an increase in O&M expenses from the test year that have not been adjusted elsewhere in the Company's filing. I made an adjustment to inflation by first adjusting the base level of O&M expenses used in the calculation to remove the test year level of expenses for additional adjustments that the Public Staff is recommending, such as to advertising, transmission O&M expense, lobbying, and sponsorships and dues. I have used the inflation factor proposed by the Company to apply to the remaining base level of O&M expenses. This resulted in a Public Staff adjustment as shown on Johnson Exhibit I, Schedule 3-8.

CUSTOMER ACCOUNTS EXPENSE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT FOR CUSTOMER ACCOUNTS EXPENSE.

A. The Company made an adjustment to customer accounts expense. The Public Staff agrees with the growth rate applied to the customer account expenses. I have removed postage associated with the customer accounts expenses since the Company reflected a postage elsewhere in the rate case filing. My adjustment is reflected on Johnson Exhibit I, Schedule 3-15.

NON-UTILTY ADJUSTMENT

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE NON-UTILITY ADJUSTMENT?

A. The Company made non-utility adjustments to allocate a share of its general administrative costs to its merchandising and jobbing (M&J) operations and its equity investment affiliates. The Public Staff applied the non-utility factors to certain additional administrative and general (A&G) senior level salaries, other corporate O&M expense accounts, and general plant accounts.

The Company allocated a portion of its plant, accumulated depreciation, and depreciation expense to its M&J operations, and its equity investment affiliates. I agreed with the Company's allocation. My adjustment is shown on Johnson Exhibit I, Schedule 3-9.

INTEREST ON CUSTOMER DEPOSITS

Q. WHAT ADJUSTMENT HAS BEEN MADE TO CUSTOMER DEPOSITS AND THE RELATED INTEREST EXPENSE?

A. PSNC reflected interest on customer deposits as a reclassification to O&M expenses based on the 13-month average of customer deposits for the period ending December 2020. Johnson Exhibit I, Schedule 3-13 reflects an adjustment that updates both the amount of customer deposits and interest on customer deposits to reflect the 13-month average for the period ending June 30, 2021.

TRANSMISSION O&M ADJUSTMENT EXPENSE

Q. PLEASE EXPLAIN THE ADJUSTMENT TO TRANSMISSION O&M ADJUSTMENT EXPENSE.

A. During discovery, the Public Staff requested information on the average cost of pipeline maintenance for the Company's new T-30 pipeline project. The Company subsequently filed a June Update adjustment to include the routine O&M cost per mile associated with the transmission project. In a data request response, the Company agreed to remove the internal labor associated with the adjustment. The Public Staff has reflected the updated O&M cost per mile in its adjustment as shown on Johnson Exhibit I, Schedule 3-10.

SERVICE COMPANY CHARGES

Q. PLEASE EXPLAIN THE ADJUSTMENT TO SERVICE COMPANY CHARGES.

A. PSNC has proposed an adjustment that increased O&M expenses for Service Company charges. The Company filed a June Update that reflected the actual Dominion Energy charges billed to PSNC from January 1, 2021, through June 30, 2021 and then annualized the charges by multiplying by 2 and comparing that amount to the test period service company charges. The Public Staff does not believe that doubling the service company charges was a reasonable approach for determining an ongoing level; therefore, I used the 12-month ended June 30, 2021, service company charges to reflect in the adjustment. My adjustment is shown on Johnson Exhibit I, Schedule 3-14.

SEVERANCE

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO SEVERANCE RELATED TO RETIREMENTS.

A. Severance costs related to retirements were included in the Company's O&M expenses. These dollars were removed from the test year, since the Public Staff has an annualized level of payroll reflected in the rate case for all current positions.

CNG TAX CREDIT

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE CNG TAX CREDIT EXPENSE.

A. The Company made an adjustment to reverse the CNG Tax Credit to increase operating expenses. Based on the fact that Congress took action to extend the tax credit to at least the end of 2021 and based on the history of the CNG tax credit, the Public Staff believes that the tax credit may easily be extended beyond 2021. Therefore, the Public Staff has reversed PSNC's adjustment, which results in a reduction in operating expenses.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

SONJA R. JOHNSON

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

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

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

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

DOCKET NO. G-5, SUB 632	)	
	)	
In the Matter of	)	
Application of Public Service Company	)	
of North Carolina, Inc., for a General	)	SETTLEMENT
Increase in Rates and Charges	)	TESTIMONY OF
	)	SONJA R. JOHNSON
DOCKET NO. G-5, SUB 634	)	PUBLIC STAFF – NORTH
	)	CAROLINA UTILITIES
In the Matter of	)	COMMISSION
Application for Approval to Modify	)	
Existing Conservation Programs and	)	
Implement New Conservation	)	
Programs	)	

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

SETTLEMENT TESTIMONY OF SONJA R. JOHNSON SUPPORTING STIPULATION

ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

October 15, 2021

Q. MS. JOHNSON, WHAT IS THE PURPOSE OF YOUR TESTIMONY IN SUPPORT OF STIPULATION IN THIS PROCEEDING?

A. The purpose of my Settlement Testimony is to support the Stipulation filed on October 15, 2021 between Public Service Company of North Carolina, Inc. (PSNC or the Company), the Public Staff, Carolina Utility Customers Association, Inc., and Evergreen Packaging, LLC (Stipulating Parties) regarding PSNC's filed updates as of June 30, 2021, and certain issues related to the Company's pending application for a general rate increase.

Q. PLEASE BRIEFLY DESCRIBE CHANGES ADDRESSED IN THE STIPULATION.

A. The Stipulation sets forth agreement between the Stipulating Parties regarding the following revenue requirement and rate issues. A reconciliation of the June updates and settlement adjustments to PSNC's filed rate increase is shown on Settlement Exhibit I:

(1) Return on Equity, Capital Structure, and Debt Cost.

(2) Update of revenues, cost of gas, rate base, and expenses to June 30, 2021.

(3) Amortization of Deferred Assets.

(4) Non-Utility Adjustment.

(5) Board of Directors Expenses.

(6) Compensation Adjustments.

(7) Miscellaneous Expense Adjustments.

(8) Uncollectibles Adjustment.

(9) Regulatory Fee Adjustment.

(10) Rate Case Expense.

(11) Depreciation Study.

(12) Hydrogen Research Program Development.

(13) CNG Tax Credit Adjustment.

The details of the agreements between the Stipulating Parties in these areas are set forth in the Stipulation.

Q. WHAT BENEFITS DOES THE STIPULATION PROVIDE FOR RATEPAYERS?

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

(a) A reduction in the Company's proposed revenue increase in this proceeding.

(b) The avoidance of protracted litigation between the Stipulating Parties before the Commission and possibly the appellate courts.

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

Q. WILL THE PUBLIC STAFF BE PRESENTING ITS CALCULATION OF THE FINAL REVENUE REQUIREMENT?

A. Yes. The Public Staff will file schedules supporting the Stipulation's recommended revenue requirement.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. HOLT: Thank you. Ms. Johnson is available for cross-examination and for questions from the Commission.

COMMISSIONER BROWN-BLAND: All right. Is there cross-examination for Ms. Johnson?

(No response.)

COMMISSIONER BROWN-BLAND: I'm not hearing anyone. Questions from the Commission?

(No response.)

COMMISSIONER BROWN-BLAND: No questions? We're making it too easy on Ms. Johnson. She's smiling about it. Does someone have a question?

(No response.)

COMMISSIONER BROWN-BLAND: No. That's all right. Well, Ms. -- Ms. Holt, it's back with you.

MS. HOLT: Thank you. I now move the admission of Ms. Johnson's testimony and exhibits.

COMMISSIONER BROWN-BLAND: All right. That motion is allowed without objection and the exhibits will be received into evidence, as well as the testimony. Exhibits marked as -- identified as marked when prefiled.

(Johnson Exhibit 1, Johnson Revised Exhibit 1 and Settlement Exhibit 1 were received into evidence.)

COMMISSIONER BROWN-BLAND: Well, Ms. Johnson, thank you. You may be excused.

THE WITNESS: Thank you.

MS. HOLT: Public Staff calls Julie Perry.

COMMISSIONER BROWN-BLAND: All right. Ms. Perry?

(WHEREUPON,

JULIE PERRY,

having been duly affirmed, testified as follows:)

COMMISSIONER BROWN-BLAND: Ms. Holt?

DIRECT EXAMINATION BY MS. HOLT:

Q. Ms. Perry, on September 23rd, 2021, did you prepare and cause to be filed in this docket testimony consisting of 16 pages, including cover sheet and appendix, and one exhibit marked Perry Exhibit 1?

A. Yes, I did.

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

A. No, I do not.

Q. If I were to ask you the same questions as in your prefiled testimony, would your answers be the same?

A. Yes, they would.

Q. On October 15th, 2021, did you prepare and cause to be filed three (3) pages of settlement testimony, including cover page, in support of the Stipulation?

A. Yes, I did.

Q. Do you have any changes or corrections to the settlement testimony?

A. No, I do not.

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

A. Yes, they would.

MS. HOLT: Chair Brown-Bland, I move that Ms. Perry's direct testimony, consisting of 16 pages, be copied into the record as if given orally from the stand; that her settlement testimony, consisting of three (3) pages, be copied into the record as if given orally from the stand; and that Perry Exhibit 1 be identified as marked when filed.

COMMISSIONER BROWN-BLAND: All right. And, Ms. Holt, I may have missed it, but just to be clear, settlement testimony was filed October --

MS. HOLT: 15th.

COMMISSIONER BROWN-BLAND: Okay. I have 18th. Is that --

MS. HOLT: I think you're correct. It did not get posted until October 18th. You are correct.

COMMISSIONER BROWN-BLAND: All right. So without objection, that motion will be allowed and the testimony -- direct and settlement testimony of witness Perry will be received into evidence and treated as if given orally from the witness stand. Her Exhibit 1 and Appendix A will be identified as they were marked when prefiled.

(Perry Exhibit 1 was marked for identification.)

(Whereupon, the prefiled direct testimony and Appendix A and prefiled settlement testimony of Julie Perry were copied into the record as if given from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

DOCKET NO. G-5, SUB 632 In the Matter of Application of Public Service Company of North Carolina, Inc., for an Adjustment of Natural Gas Rates and Charges in North Carolina DOCKET NO. G-5, SUB 634 In the Matter of Application for Approval to Modify Existing Conservation Programs and Implement New Conservation Programs	TESTIMONY OF JULIE G. PERRY PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632

TESTIMONY OF JULIE G. PERRY

ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 23, 2021

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

A. My name is Julie G. Perry. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Accounting Manager for Natural Gas and Transportation with the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. PLEASE BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are set forth in Appendix A.

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

A. The purpose of my testimony is to present my review of the proposed ratemaking adjustments for regarding federal protected Excess Deferred Income Taxes (EDIT), federal unprotected EDIT, state EDIT, and the deferred revenues associated with the over collection of taxes since January 1, 2018, due to changes in the federal tax rate applicable to Public Service Company of North Carolina, Inc. (PSNC or the Company).

I am also providing testimony regarding plant investment related to the Integrity Management Tracker (IMT) mechanism and tariff, Energy Efficiency and Green Therm mechanisms, a special contract adjustment, and the Durham incident costs.

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

A. My investigation included a review of the application, testimony, exhibits, and other data filed by PSNC. The Public Staff has also conducted extensive discovery in this matter, reviewed responses provided by the Company in response to the Public Staff's numerous data requests, and participated in extensive virtual conference calls with the Company.

Q. PLEASE DESCRIBE YOUR TESTIMONY AND EXHIBITS.

A. My exhibits are as follows:

- Perry Exhibit I, Schedule 1 sets forth the calculation of the federal unprotected EDIT Rider to be in effect for five years.

- Perry Exhibit I, Schedule 1(a) sets forth the calculation of the unprotected EDIT Rider annuity factor.
- Perry Exhibit I, Schedule 2 sets forth the calculation of the state EDIT Rider, which the Public Staff recommends be refunded in two years.
- Perry Exhibit I, Schedule 2(a) sets forth the calculation of the state EDIT Rider annuity factor.
- Johnson Exhibit I, Schedule 2-1 and Schedule 3 sets forth the Special Contract Adjustment.
- Johnson Exhibit I, Schedule 3 sets forth the Durham incident expense adjustment.
- Deferral Request – AFUDC Equity
- Integrity Management Tracker
- Energy Efficiency Mechanism
- Green Therm Mechanism

TAX CUTS AND JOBS ACT EFFECTS

Q. HAVE YOU REVIEWED THE COMPANY'S PROPOSAL TO ADDRESS THE EFFECTS OF THE TAX CUTS AND JOBS ACT (TAX ACT)?

A. Yes.

Q. WHAT IS YOUR UNDERSTANDING OF THE COMPANY'S PROPOSAL?

A. The Company has proposed an EDIT Rider to return to ratepayers (1) federal EDIT and (2) over collected revenues that have accrued since January 1, 2018, both of which are related to the federal tax rate decrease provision of the Tax Act, as well as state EDIT resulting from various state income tax changes.

Q. WHAT ARE THE DIFFERENCES BETWEEN THE COMPANY'S AND THE PUBLIC STAFF'S PROPOSALS TO ADDRESS THE EFFECTS OF THE TAX ACT AND THE STATE TAX CHANGES?

A. The Company and the Public Staff differ as to (1) the rate at which unprotected federal EDIT should be flowed back to ratepayers, (2) the rate at which state EDIT should be flowed back to ratepayers, and (3) the rate at which the over collection (since January 1, 2018) of deferred revenues due to the decrease in federal tax rates should be flowed back to ratepayers.

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S GENERAL CONCERNS REGARDING PSNC'S PROPOSED EDIT RIDER.

A. PSNC has proposed an EDIT Rider that contains the following categories of refunds for customers:

(1) Federal EDIT – Unprotected

(2) State EDIT

(3) Deferred Revenue from Tax Act Over Collections

The Public Staff notes and agrees with PSNC's adjustment to reflect the Federal EDIT – Protected amortization in base rates, as well as PSNC removed the accumulated deferred income taxes related to the three EDIT riders proposed from rate base in this case.

FEDERAL EDIT:

Q. PLEASE EXPLAIN WHAT IS MEANT BY PROTECTED AND UNPROTECTED FEDERAL EDIT.

A. The federal EDIT consists of two categories, protected and unprotected EDIT. The protected EDIT are deferred taxes related to timing differences arising from the utilization of accelerated depreciation for tax purposes and another depreciation method for book purposes. These deferred taxes are deemed protected because the IRS does not permit regulators to flow back the excess to ratepayers immediately, but instead requires that the excess be flowed back to ratepayers ratably over the life of the timing difference that gave rise to the excess, per IRC Section 203(e).

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO PROTECTED FEDERAL EDIT?

A. The Company has calculated the known and measurable protected EDIT based on Internal Revenue Service (IRS) normalization rules, as required by the Tax Act. The Company reflected the amortization of the refund of its protected EDIT balance in base rates using the ARAM method. The Public Staff agrees with the Company's approach.

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO UNPROTECTED FEDERAL EDIT?

A. In its proposed EDIT Rider, the Company seeks to amortize its unprotected EDIT balance over seven years.

Q. PLEASE DESCRIBE YOUR PROPOSED ADJUSTMENT TO UNPROTECTED FEDERAL EDIT.

A. I agree with the removal of unprotected federal EDIT from rate base and I recommend amortizing the unprotected EDIT regulatory liability in a rider to be refunded to ratepayers over five years on a levelized basis, with carrying costs.

The immediate removal of unprotected federal EDIT from rate base increases the Company's rate base and mitigates regulatory lag that might result from refunds of unprotected EDIT not being contemporaneously reflected in rate base. Furthermore, removing the total amount of the unprotected federal EDIT credit from rate base in the current rate case provides the Company with an increase in rates to moderate any cash flow issues that might arise. The financing cost to the Company will be imposed ratably over the period that the EDIT is returned through the levelized rider.

Q. WHY DOES THE PUBLIC STAFF RECOMMEND A FIVE-YEAR AMORTIZATION FOR UNPROTECTED EDIT?

A. The Public Staff believes that a five-year period would increase rate stability for ratepayers during the flow back period. While a shorter rider would flow the money back to ratepayers more quickly, it would also result in a larger de facto rate increase when the rider expired at the end of the amortization period. A five-year rider would smooth the rate impact and result in a significantly smaller increase after the rider expires. Additionally, the levelized rider would include a return, thus ensuring that ratepayers are made whole.

This amortization period is consistent with the amortization period approved by the Commission in general rate cases, including Duke Energy Carolina's (DEC) 2019 general rate case (Docket No. E-7, Sub 1214), Duke Energy Progress's (DEP) 2019 general rate case (Docket No. E-2, Sub 1219), Carolina Water Service Inc. of North Carolina's 2018 general rate case in Docket No. W-354, Sub 360, and in Piedmont Natural Gas, Inc.'s (Piedmont) general rate case in Docket No. G-9, Sub 743.

STATE EDIT:

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO STATE EDIT?

A. PSNC has proposed to refund the state EDIT resulting from the various state income tax changes to ratepayers, including the correction of a previous state income tax refund calculation, over a five-year period.

Q. PLEASE EXPLAIN THE PUBLIC STAFF'S ADJUSTMENT TO STATE EDIT.

A. I am recommending an adjustment to the amortization period proposed for the state EDIT in this case. Specifically, I recommend the amount be refunded to ratepayers over a two-year period on a levelized basis, with carrying costs. The immediate removal of state EDIT from rate base increases the Company's rate base, and mitigates regulatory lag that might occur from refunds of state EDIT not being contemporaneously reflected in rate base. As with my proposed adjustment to unprotected federal EDIT, removing the total amount of the state EDIT credit from rate base in the current case provides the Company with an increase in rates to moderate any cash flow issues that may occur.

Q. WHY DID THE PUBLIC STAFF RECOMMEND A TWO-YEAR AMORTIZATION PERIOD FOR STATE EDIT?

A. The Public Staff's recommended amortization period is consistent with Commission orders in PSNC's last general rate case in Docket No. G-5, Sub 565 and in Dominion Energy North Carolina's (DENC) general rate case in Docket No. E-22, Sub 532, in which the Commission approved either a one-year flow back or a two-year flow back of state EDIT to ratepayers. We believe that this amortization period represents a reasonable and consistent methodology and should be approved for PSNC in this case as well.

REVENUE DEFERAL FROM OVERCOLLECTION OF FEDERAL TAXES:

Q. WHAT IS THE COMPANY'S PROPOSAL WITH RESPECT TO ITS REVENUE DEFERRAL FROM THE OVERCOLLECTION OF FEDERAL INCOME TAXES SINCE JANUARY 1, 2018?

A. The Company proposes to refund to ratepayers the overcollection of federal taxes (from January 1, 2018, through January 31, 2019), which resulted from the Tax Act's reduction of federal tax rates, over a two-year period. PSNC has been accruing interest on these funds calculated at the net of tax overall rate of return since January 1, 2018.

Q. WHAT IS YOUR RECOMMENDATION REGARDING HOW THE COMPANY SHOULD REFUND THE OVERCOLLECTION OF FEDERAL TAXES DUE TO THE TAX ACT?

A. I recommend that PSNC refund the amount plus interest as of the effective date of rates in the current docket, over a one-year period.

Q. WHY DOES THE PUBLIC STAFF RECOMMEND A ONE-YEAR AMORTIZATION PERIOD FOR THE OVERCOLLECTION OF REVENUE DUE TO THE FEDERAL INCOME TAX CHANGE?

A. The Public Staff's recommended amortization period is consistent with Commission orders in both Cardinal Pipeline, Docket No. G-39, Sub 42, DENC, Docket No. E-22, Sub 560, [tax dockets], and the Sub 743 Piedmont rate case docket in which the Commission approved a one-year time period or a one-time bill credit over which to flow back the overcollection of revenues to ratepayers due to the federal income tax change. We believe that this amortization period represents a reasonable and consistent methodology and should be approved for PSNC as well.

SPECIAL CONTRACTS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO SPECIAL CONTRACTS.

A. The Company provides natural gas transportation service to a power plant located near Asheville, North Carolina, pursuant to a contract dated March 10, 2000. Although the contract has a 25-year term, the customer paid demand charges over the initial five years of the contract for the actual cost of the facilities installed by PSNC pursuant to the contract. The contract also requires the customer to pay PSNC separate charges related to PSNC's ongoing fuel, O&M expenses, and property taxes. No demand charge payments from the customer related to the plant were reflected in the Company's revenues in its current rate case filing. The adjustment, which is shown on Johnson Exhibit I, Schedules 2(a) and 3, removes from the cost of service the amounts included by the Company for plant, accumulated depreciation, accumulated deferred income taxes, and depreciation expense associated with the facilities installed by PSNC.

DURHAM INCIDENT

Q. PLEASE EXPLAIN YOUR RECOMMENDATION REGARDING THE DURHAM INCIDENT LEGAL EXPENSES INCURRED IN 2020.

A. On April 10, 2019, in Durham, North Carolina, a natural gas service line was breached causing an explosion resulting in death, personal injury, and property damage (Durham Incident). While there has been no report of any wrongdoing on PSNC's part, PSNC has incurred substantial legal bills related to pending litigation initiated by numerous affected parties in several filed cases. The Public Staff considers the Durham Incident to be an extraordinary, non-recurring event and has removed the legal fees incurred in 2020 from the Company's cost of service. In addition, there are excess liability insurance policies in place that may cover these types of legal expenses once all litigation is resolved.

DEFFERRAL REQUEST – AFUDC EQUITY

Q. PLEASE EXPLAIN YOUR RECOMMENDATION TO THE COMPANY'S DEFERRAL REQUEST REGARDING AFUDC EQUITY.

A. The Public Staff is completing its investigation into the Company's deferral request related to AFUDC Equity. We have a few outstanding questions and a final recommendation of the Public Staff will be provided in supplemental testimony.

IMT MECHANISM AND TARIFF

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE IMT MECHANISM?

A. As discussed in the Public Staff's 2020 Annual IMT Report in Docket No. G-5, Subs 565C and 628, the Public Staff determined during its review of PSNC's IMRR model that additional modifications may be needed to the model to address some of the Public Staff's concerns. The Public Staff is primarily concerned with how the Company determines accumulated depreciation and ADIT in the IMRR calculation and believes that these entries should be recorded in the same month that plant and annual depreciation expense is allowed to begin. The Public Staff plans to send to PSNC a template of its proposed modifications to the mechanism prior to the Company's Annual IMR filing on January 31, 2022 and will work with the Company to implement these changes.

The Public Staff will also work with the Company to update the tariff inputs for the margin percentages by month and by rate class, as well as the special contract credits once this hearing is complete and a final order has been issued.

ENERGY EFFICIENCY PROGRAM MECHANISM

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RECOVERY OF THE EE PROGRAMS?

A. Based on the Public Staff's recommendation to approve the Company's portfolio of programs as pilot programs for a three-year period, we have determined that the Public Staff does not oppose the implementation of an EE Rider. The structure of this Rider still remains under discussion and the final recommendation of the Public Staff will be provided in supplemental testimony.

GREEN THERM PROGRAM MECHANISM

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE RECOVERY OF THE GREEN THERM PROGRAM?

A. The Public Staff is not recommending approval of the Company's Green Therm Program at this time; however, the Public Staff supports PSNC's proceeding with developing the program and then filing with the Commission for final approval. The Public Staff intends to reserve its recommendation until the Company has determined its final costs. Therefore, the recovery mechanism remains under discussion and the final recommendation of the Public Staff will be provided in supplemental testimony.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JULIE G. PERRY

I graduated from North Carolina State University in 1989 with a Bachelor of Arts degree in Accounting and I am a Certified Public Accountant.

Prior to joining the Public Staff, I was employed by the North Carolina State Auditor's Office. My duties there involved the performance of financial and operational audits of various state agencies, community colleges, and Clerks of Court.

I joined the Public Staff in September 1990 and was promoted to Supervisor of the Natural Gas Section in the Accounting Division in September 2000. I was promoted to Accounting Manager – Natural Gas & Transportation effective December 1, 2016. I have performed numerous audits and/or presented testimony and exhibits before the Commission addressing a wide range of natural gas topics.

Additionally, I have filed testimony and exhibits in numerous water rate cases and performed investigations and analyses addressing a wide range of topics and issues related to the water, electric, transportation, and telephone industries.

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

DOCKET NO. G-5, SUB 632 In the Matter of Application of Public Service Company of North Carolina, Inc., for an Adjustment of Natural Gas Rates and Charges in North Carolina DOCKET NO. G-5, SUB 634 In the Matter of Application for Approval to Modify Existing Conservation Programs and Implement New Conservation Programs	SETTLEMENT TESTIMONY OF JULIE G. PERRY PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

SETTLEMENT TESTIMONY OF JULIE G. PERRY SUPPORTING STIPULATION

ON BEHALF OF THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

OCTOBER 15, 2021

Q. MS. PERRY, WHAT IS THE PURPOSE OF YOUR SETTLEMENT TESTIMONY IN THIS PROCEEDING?

A. The purpose of my settlement testimony is to support the Stipulation of Settlement (Stipulation) between Public Service Company of North Carolina, Inc. (PSNC or the Company), the Public Staff, Carolina Utility Customers Association, Inc., and Evergreen Packaging, LLC (collectively, the Stipulating Parties) dated October 15, 2021, and provide testimony regarding PSNC's Energy Efficiency Program and GreenTherm^{TM} mechanisms.

Q. PLEASE BRIEFLY DESCRIBE THE TERMS OF THE STIPULATION.

A. The Stipulation sets forth agreement between the Stipulating Parties regarding the following revenue requirement and rate issues that I am responsible for:

(1) Return the unprotected federal excess deferred income taxes (EDIT) due to the Tax Cuts and Jobs Act to customers.

(2) Return the remaining North Carolina state EDIT due to reductions in state tax rates and make corrections to prior State EDIT refunds.

(3) Return the deferred revenues associated with the over collection of federal taxes.

(4) Durham Incident Legal Fees.

(5) Deferral Request - AFUDC Equity.

(6) Gas Extension Feasibility Model.

(7) Continuation of the Integrity Management Tracker.

(8) Energy Efficiency Rider.

(9) GreenTherm™ Mechanism.

(10) In addition to the settled issues having a revenue requirement impact in the present case, the Stipulation also reflects audit and reporting obligations for Transmission Integrity Management Program (TIMP) costs, Distribution Integrity Management (DIMP) costs, and legal costs related to the Durham Incident.

The details of the Stipulating Parties' agreement regarding these issues are set forth in the Stipulation.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

MS. HOLT: Thank you. Ms. Perry is available for cross-examination and Commission questions.

COMMISSIONER BROWN-BLAND: All right. Thank you. Cross-examination for Ms. Perry?

(No response.)

COMMISSIONER BROWN-BLAND: I'm not hearing any cross, so questions from Commission? Chair Mitchell?

CHAIR MITCHELL: Thank you, Commissioner Brown-Bland.

EXAMINATION BY CHAIR MITCHELL:

Q. Good morning, Ms. Perry. How are you this morning?

A. Good morning. Doing well.

Q. All right. I have a few questions for you related to the AFUDC equity. Were you able to hear my discussion with company witness Spaulding?

A. I was, yes.

Q. And in your testimony -- well, in your -- in your direct testimony, your -- your initial testimony, you indicate that -- and I'm looking at Page 13, if you want to go there. But you indicate that you have a few questions about the company's deferral request regarding AFUDC equity and a final recommendation would be provided in supplemental testimony.

Is it -- did I -- did you-all provide a final recommendation and supplemental testimony or did you simply reach an agreement that was memorialized in the Stipulation?

A. So I think the settlement is just twofold. It's also -- it's supplement and the settlement. I think we had some -- I mean, it's a -- this is a confusing issue, and we had many, many calls with the Tax Department leading up from filing -- you know, before filing, after filing and to the settlement.

So I could probably try to explain it to you at a higher level, but in a more detailed level than what you've seen it in -- written so far from -- from our side, if you'd like.

Q. Yes. Please do that and -- and try to explain it in layman's terms.

A. Yes.

Q. Just remember I'm not a -- I'm not a -- I'm not an accountant and I'm not a tax attorney. But help us, you know, put this -- just explain the issue for us. Describe from the very beginning what -- what this is and -- and everything that you know about -- about the issue.

A. I think -- I think -- and I think these are terms that you're familiar with. So I tried to frame this in a way that -- that you guys would understand.

So AFUDC is the return that is being accrued on a construction work in progress project, before it goes into planned service. So during construction phase, they're allowed to earn a return on that budget cost while it's being constructed.

Okay. That return is usually the net of tax overall rate of return.

Okay. We've seen that in all of our filings, this kind of thing. So what we don't get into is the whole tax impact. And so for tax purposes, that AFUDC rate is -- is -- contains equity and debt. I mean, you know, you look at your capital structure. You look at all your returns. Everything is equity and debt.

Debt is tax -- you can -- you can deduct it for tax purposes. Equity, you cannot. So what happens with -- at least in PSNC's case is under the generally accepted accounting principles, which I know we don't want to go into too much, they were having to basically book a -- a deferred tax liability related to permanent differences related to not being able to deduct that for tax purposes.

Okay. So, in essence, because of this net of tax issue that they say their auditors were worried about is -- asking them to accrue this liability, which I believe is from the last rate case. I'm not sure if it's prior to that. I think this did sort of stem from the 2016 rate case, in answer to one of your earlier questions.

But what we're doing here is, you know, I think the company's allowed to -- to -- to get -- you know, recover a hundred percent of AFUDC. And what this is doing is when that deferred tax liability is -- reducing rate base was what it does.

Okay. In essence, up until this point, they've basically not been allowed to get a return on their entire AFUDC that's in rate base. By giving this regulatory asset, it offsets the liability that's already there, sort of makes it null. And so AFUDC that should have been there and then been depreciated in plant like all the other plant, it would make it a hundred percent recoverable and it would just be depreciated over the course of the plant's life.

Okay. Now, as far as revenue requirement impact, they made this adjustment in the test year, basically. They added the asset in -- the cost of service in the test period. So that's why you don't see a numerical adjustment here.

Okay. So, basically, the adjustment in question is around 13.33 million dollars. You multiply that by your tax fact -- your factors on -- I guess it's Exhibit B of the settlement, where we have the factors laid out. It's the rate base factors. It's point-oh-eight-something-something. Anyway, it's, like, around 1.1 million dollars.

But I think wohat this is doing, it's getting them to where they are whole now on the AFUDC, as far as we can tell. And I'm not sure how other -- how other utilities are doing. We just had to look at how PSNC had been doing it, but going forward this should be fixed.

Okay. With the language that we have in there adjusted for tax savings, you know, things of that nature -- much more technical terms than I really want to -- you know, than we -- any of us want to know about. And I can send you late-filed exhibits on journal entries which would bore you to death, but I think this gets them whole, gets them back right. And then going forward, I think the situation is resolved. Does that help?

Q. It does. And so, Ms. Perry, I asked the company to provide a late-filed exhibit, and I think you -- did you hear my request for that late-filed exhibit?

A. I'm not -- yeah. I think it was an explanation or was it a calculation?

Q. Well, it was -- it was mostly explanation, but I may go ahead and ask you to provide the journal entries just so our folks --

A. Certainly.

Q. -- can review and follow those.
A. Sure.
Q. So I would ask -- and I'm actually -- I'm -- I'm -- I'm adding that to my request to the company.
CHAIR MITCHELL: Ms. Grigg, I see you -- would you just add that to the request?
BY CHAIR MITCHELL:
Q. And then, Ms. Perry, if you would work with the company in preparing its response to this request. I won't ask y'all both -- I won't ask Public Staff to provide a competing response, but if y'all could just work together and get something to us, I would appreciate that.
A. Sure. Of course. It's a very complicated issue, so -- yeah.
CHAIR MITCHELL: Okay. All right. I have nothing further for Ms. Perry. Thank you very much.
COMMISSIONER BROWN-BLAND: All right. Other Commissioners have questions for this witness?
(No response.)
COMMISSIONER BROWN-BLAND: All right. Other questions from -- on the Commission's questions?
(No response.)
COMMISSIONER BROWN-BLAND: No? Ms. Grigg, no questions?

MS. GRIGG: No, ma'am.

COMMISSIONER BROWN-BLAND: All right. Back to you, Ms. Holt.

MS. HOLT: Thank you. Chair Brown-Bland, at this time, I'd like to move the admission of Ms. Perry's -- if I haven't already -- direct testimony, settlement testimony and her Exhibit 1 into evidence.

COMMISSIONER BROWN-BLAND: The testimony is already in and the exhibit is now received into evidence, identified as it was marked when prefiled, along with Appendix A.

(Perry Exhibit 1 was received into evidence.)

COMMISSIONER BROWN-BLAND: All right. Ms. Perry, you may be excused. Thank you very much.

I believe that is it for the live witnesses today. Am I correct?

MS. CRESS: Presiding Commissioner Brown-Bland, this is Christina Cress with Evergreen. My apologies. I do need to amend my earlier motion. I'm not sure if now would be the most appropriate time to do that, but my staff has alerted me that I was inadvertently referring to a not-final version of witness Collins' testimony and exhibits when I made my motion earlier.

COMMISSIONER BROWN-BLAND: All right. Let me -- let me come back to you just so that the record will keep Public Staff's evidence together in one place. But don't let me forget.

MS. CRESS: Yes, ma'am. Thank you.

COMMISSIONER BROWN-BLAND: All right. Ms. Holt?

MS. HOLT: Yes. At this time, I'd like to move the admission of the testimony and exhibits that were filed on September 23rd, 2021, for the following Public Staff witnesses.

I'd like to move the prefiled direct testimony of Mary Coleman, consisting of eight (8) pages, including cover and appendix. I move that they be copied into -- this testimony be copied into the record as if given orally from the stand and that her Exhibit 1 be identified as marked and entered into evidence.

COMMISSIONER BROWN-BLAND: All right. Without objection, that motion is allowed.

(Coleman Exhibit 1 was marked for identification and received into evidence.)

(Whereupon, the prefiled direct testimony and Appendix A of Mary Coleman were copied into the record as if given from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

DOCKET NO. G-5, SUB 632 In the Matter of Application of Public Service Company of North Carolina, Inc., for a General Increase in Rates and Charges DOCKET NO. G-5, SUB 634 In the Matter of Application for Approval to Modify Existing Conservation Programs and Implement New Conservation Programs	))))))))))))	TESTIMONY OF MARY A. COLEMAN PUBLIC STAFF-NORTH CAROLINA UTILITIES COMMISSION

PUBLIC SERVICE COMPANY OF NORTH CAROLINA, INC.

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

TESTIMONY OF MARY A. COLEMAN

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 23, 2021

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

A. My name is Mary A. Coleman. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Staff Accountant in the Accounting Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are set forth in Appendix A.

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

A. The purpose of my testimony is to present the results of my investigation into the application of Public Service Company of North Carolina, Inc. (PSNC or the Company), for a general rate increase in this proceeding.

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

A. My investigation included a review of the application, testimony, exhibits, and other data filed by PSNC. I also conducted extensive discovery in this matter, including the review of numerous responses from the Company to Public Staff data requests, and participation in telephone meetings with representatives of the Company to discuss unanswered questions and to receive clarification on the Company's responses to Public Staff data request questions related to executive compensation, board of directors expenses, aviation, and insurance expense.

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

A. I recommend adjustments in the following areas:

(1) Board of Directors Expenses
(2) Other Benefits
(3) Executive Compensation

<u>BOARD OF DIRECTORS (BOD) EXPENSES</u>

Q. PLEASE EXPLAIN YOUR PROPOSED ADJUSTMENT TO BOD EXPENSES.

A. I recommend an adjustment to remove 50% of the expenses associated with the BOD of Dominion Energy Corporation (Dominion

Energy) that have been allocated to PSNC, as reflected in Coleman Exhibit I, Schedule 1. Based on information received through the Company's data request responses, the Public Staff made an adjustment to remove expenses related to directors' and officers' liability insurance, because there were no expenses allocated to PSNC for the BOD compensation or other BOD miscellaneous expenses during the test period.

<u>OTHER BENEFITS</u>

Q. PLEASE EXPLAIN YOUR PROPOSED ADJUSTMENT TO OTHER BENEFITS.

A. The Company used the actual test year relationship of total SCANA payroll benefits to total SCANA payroll in computing the payroll benefits factor and applied it to the PSNC payroll adjustment in the current case. PSNC's payroll benefits include 401K, long-term disability, and short-term disability. The Public Staff updated the payroll benefits factor to reflect the actual ratio excluding the short-term disability since it was no longer considered part of benefits beginning in 2021. I then applied the revised benefits factor to the updated payroll adjustment to determine the updated adjustment for payroll-related benefits, as reflected on Johnson Exhibit I, Schedule 3-2.

EXECUTIVE COMPENSATION

Q. PLEASE EXPLAIN YOUR PROPOSED ADJUSTMENT TO EXECUTIVE COMPENSATION.

A. The Company did not propose an adjustment for the Dominion Energy executives who charged compensation expenses to PSNC.

As shown on Coleman Exhibit I, Schedule 2, the Public Staff made an adjustment to remove 50% of the compensation for the five executives who have charged the highest compensation to PSNC during the test period. This compensation is comprised of total annual salary, benefits, and short and long-term incentive payments.

Q. WHY DID YOU SELECT THE EXECUTIVES CHARGING THE HIGHEST COMPENSATION?

A. The Public Staff believes that basing executive compensation on the five executives who have charged the highest compensation to PSNC is appropriate, because these positions are more closely aligned with PSNC's efforts to minimize costs and maximize the reliability of the Company's service to customers.

This approach is consistent with the Public Staff's executive compensation adjustment in Piedmont Natural Gas Company, Inc.'s 2016 rate case in Docket No. G-9, Sub 743 and its 2021 rate case in G-9, Sub 781.

Q. IS YOUR RECOMMENDATION BASED ON THE PREMISE THAT THE COMPENSATION OF THE EXECUTIVES YOU HAVE SELECTED ARE EXCESSIVE OR SHOULD BE REDUCED?

A. No. This recommendation is based on the Public Staff's belief that it is appropriate and reasonable for the shareholders of the very large natural gas and electric utilities to bear some of the cost of compensating those individuals who are most closely linked to furthering shareholder interests, which are not always the same as those of ratepayers.

Q. WHAT IS THE PREMISE FOR REMOVING 50% OF THE TOP EXECUTIVES' COMPENSATION?

A. Officers have fiduciary duties of care and loyalty to shareholders, but not to customers. Consequently, the Company's executive officers are obligated to direct their efforts not only to minimizing the costs and maximizing the reliability of PSNC's service to customers, but also to maximizing the Company's earnings and the value of its shares. It is reasonable to expect that management will serve the shareholders as well as the ratepayers; therefore, a portion of management's compensation and pensions should be borne by the shareholders.

Adjusting the compensation of the some of the top executives is consistent with the positions taken by the Public Staff in past general rate cases involving investor-owned utilities serving North Carolina retail customers. Some of these cases include Duke Energy Carolina's (DEC) 2018 General Rate Case (Docket No. E-7, Sub 1146), Public Service Company of North Carolina's (PSNC) 2016 General Rate Case (Docket No. G-9, Sub 565), and Piedmont's 2013 General Rate Case (Docket No. G-9, Sub 631). DEC, DEP, and Dominion Energy North Carolina have all made executive compensation adjustments in their respective general rate cases to remove a portion of their top executives' total compensation. The Public Staff has consistently updated each utility's adjustments to reflect a 50% reduction of the top executives' total compensation in each of the general rate case proceedings.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

Mary A. Coleman

I am a graduate of North Carolina State University with a Bachelor of Accountancy degree and a Bachelor of Arts degree in Business Management.

Prior to joining the Public Staff, I was a Financial Consultant focusing mainly on non-profit organizations from 2013 until 2017. I was employed as a Consultant in places such as University of North Carolina-Chapel Hill, North Carolina State University, City of Raleigh-Community Development Office, Neuro Community Care, and the Carolina Center for Medical Excellence. Before I became a Consultant, I was the Chief Financial Officer for several organizations, including the North Carolina Justice Center where I worked for ten years.

I joined the Public Staff as a Staff Accountant in December 2017. Since joining the Public Staff I have assisted on natural gas, electric, and water proceedings.

MS. HOLT: I move that the prefiled testimony of Lynn Feasel, consisting of eight (8) pages, including cover and appendix, be copied into the record as if given orally from the stand and that her one exhibit be identified as marked when filed and entered into evidence.

COMMISSIONER BROWN-BLAND: And without objection, that motion is also allowed.

(Feasel Exhibit 1 was marked for identification and received into evidence.)

(Whereupon, the prefiled direct testimony and Appendix A of Lynn Feasel were copied into the record as if given from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

DOCKET NO. G-5, SUB 632

In the Matter of
Application of Public Service Company of North Carolina, Inc., for an Adjustment of Natural Gas Rates and Charges in North Carolina

DOCKET NO. G-5, SUB 634

In the Matter of
Application for Approval to Modify Existing Conservation Programs and Implement New Conservation Programs

TESTIMONY OF
LYNN FEASEL
PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

TESTIMONY OF LYNN FEASEL

ON BEHALF OF THE PUBLIC STAFF –
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 23, 2021

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

A. My name is Lynn Feasel. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Staff Accountant with the Accounting Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

A. My qualifications and duties are set forth in Appendix A.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the results of my investigation into the application of Public Service Company of North Carolina, Inc. (PSNC or the Company), for a general rate increase in this proceeding.

Q. BRIEFLY EXPLAIN THE SCOPE OF YOUR INVESTIGATION REGARDING THIS RATE INCREASE APPLICATION.

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

Q. PLEASE DESCRIBE THE ADJUSTMENTS YOU RECOMMEND.

A. I have recommended the following adjustments, which impact rate base and operating expenses, to Public Staff witness Johnson to incorporate into her exhibits:

(1) Other Working Capital Updates;
(2) Deferred Transmission Pipeline Integrity Costs;
(3) Deferred Distribution Pipeline Integrity Costs; and
(4) Lead Lag Study.

<u>OTHER WORKING CAPITAL UPDATES</u>

Q. PLEASE EXPLAIN YOUR ADJUSTMENTS FOR OTHER WORKING CAPITAL UPDATES.

A. Except for the postretirement benefits and pension accrual, I have updated the other working capital items, using a 13-month average as of June 30, 2021, the Public Staff's cutoff date for post-test year plant additions in this filing. For postretirement benefits and pension accrual, I updated the Company's filed balance as of December 31, 2020 to the balance as of June 30, 2021.

DEFERRED TRANSMISSION PIPELINE INTEGRITY COSTS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEFERRED TRANSMISSION PIPELINE INTEGRITY COSTS.

A. The Company's adjustment for deferred Transmission Integrity Management Program (TIMP) costs is composed of the amounts paid to outside vendors in connection with the TIMP program between July 1, 2016, and December 31, 2020, as revised through June 30, 2021 in the Company's filed June update. The Public Staff has reviewed these charges, as well as the updated deferred TIMP charges through June 30, 2021, and made adjustments to remove expenses without invoice support and other non-eligible expenses. The Public Staff has also reflected the existing amortization from the Sub 565 rate case through December 31, 2021, the estimated effective date of rates in the current rate case. The Public Staff recommends that the balance of the deferred TIMP costs, net of prior amortizations, be amortized over a five-year period consistent with the Company's proposed amortization period in the Company's original filing. My adjustment for the TIMP amortization is shown on Feasel Exhibit I, Schedule 1.

DEFERRED DISTRIBUTION PIPELINE INTEGRITY COSTS

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO DEFERRED DISTRIBUTION PIPELINE INTEGRITY COSTS.

A. The Company's adjustment for Distribution Integrity Management Program (DIMP) costs is composed of the amounts paid to outside vendors in connection with the DIMP program between July 1, 2016, and December 31, 2020, as revised through June 30, 2021 in the Company's filed June update. The Public Staff has reviewed these charges, as well as the updated deferred DIMP costs from January 1, 2021 through June 30, 2021, and made adjustments to remove expenses without invoice support and other non-eligible expenses. The Public Staff has also reflected the existing amortizations from the Sub 565 rate case through December 31, 2021, the estimated effective date of rates in the current rate case. The Public Staff recommends that the balance of the deferred DIMP costs be amortized over a five-year period consistent with the Company's proposed amortization period in the Company's original filing. My adjustment to the DIMP amortization is shown on Feasel Exhibit I, Schedule 2.

LEAD LAG STUDY

Q. PLEASE EXPLAIN YOUR ADJUSTMENT TO THE LEAD LAG STUDY.

A. The Lead Lag study reflects the lag days between when the Company bills customers for payment for service rendered and when those payments are actually collected by the Company. The Company needs funds during this time period to maintain routine daily operations. The purpose of a lead lag study is to calculate the amount of funding that the Company requires for this period of time. PSNC's G-1, Item 26 - Lead Lag Study – 2021 shows the supporting details for the Company's calculation of the test period and the proforma lead lag cash working capital for this proceeding.

The Company's approach to calculating the lead lag cash working capital is as follows: First, the Company calculated total revenue lag days by adding the service period lag, billing lag, and collection lag together. Second, the Company calculated expense lag days by selecting a sufficient amount of samples, calculating the dollar days for each expense, adding up the total dollar days and total amounts, and calculating the overall expense lag days. Third, the Company calculated net (lead) lag days by deducting expense (lead) lag days from revenue lag days. Fourth, the Company divided net (lead) lag days by 365 days to calculate the net interval percentage. Lastly, the

Company multiplied each cost of service, interest on long-term and short-term debts, and income available for common equity by a net interval percentage to calculate the total cash working capital required.

The Public Staff agrees with the methodology the Company used to calculate net cash working capital in the lead lag study using lead lag days calculated from the Company's 2019 revenue and expense data. The Public Staff applied the same methodology to calculate net cash working capital in its lead lag study, as adjusted for the revenue and expense adjustments proposed by the Public Staff in this case. The Public Staff discovered a formula error in the Company's calculation of other O&M expense lag days. The Public Staff has corrected the formula, which resulted in a change of other O&M expense lag days from 6.18 lag days to 6.36 lag days; therefore, the overall O&M expense lag days was changed from 16.26 to 16.33. The Public Staff discovered another formula error when calculating income available for common equity. The Company did not deduct interest on short-term debt from total operating income for return. The Public Staff corrected this error which reduced the income available for common equity.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

LYNN FEASEL

I am a graduate of Baldwin Wallace University with a Master of Business Administration degree in Accounting. I am a Certified Public Accountant licensed in the State of North Carolina. Prior to joining the Public Staff, I was employed by Franklin International in Columbus, Ohio, from June 2011 through June 2013. Additionally, I worked for ABB Inc. from September 2013 through October 2016.

I joined the Public Staff as a Staff Accountant in November 2016. Since joining the Public Staff, I have worked on rate cases involving water and sewer utilities and natural gas utilities, filed testimony and affidavits in various general rate cases, calculated quarterly earnings for Carolina Water Service, Inc. of North Carolina and Aqua North Carolina, Inc., calculated quarterly earnings for various natural gas utilities, calculated refunds to consumers from AH4R and Progress Residential, and reviewed franchise and contiguous filings for multiple water and sewer utilities.

MS. HOLT: I move that the prefiled direct testimony of Jack Floyd, consisting of 19 pages, including cover and appendix, be copied into the record as if given orally from the stand.

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

(Whereupon, the prefiled direct testimony and Appendix A of Jack Floyd were copied into the record as if given from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

DOCKET NO. G-5, SUB 632 In the Matter of Application of Public Service Company of North Carolina, Inc., for a General Increase in Rates and Charges DOCKET NO. G-5, SUB 634 In the Matter of Application for Approval to Modify Existing Conservation Programs and Implement New Conservation Programs	))))))))))))	TESTIMONY OF JACK FLOYD PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

TESTIMONY OF JACK L. FLOYD

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 23, 2021

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

A. My name is Jack L. Floyd. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am an Engineer and Manager of Rates and Energy Services – Electric Section of the Energy Division of the Public Staff – North Carolina Utilities Commission.

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the Public Staff's analysis and recommendations concerning issues related to apportioning the base margin revenue changes that will result from this case among the various customer classes of Public Service Company of North Carolina, Inc. (PSNC or the Company). In my analysis, I considered class rates of return (ROR) on rate base under present rates, and principles the Public Staff has historically considered in evaluating proposed revenues in setting base rates. I also discuss issues of affordability that are affecting natural gas utility customers.

Q. WHAT DID YOU REVIEW IN DEVELOPING THE PUBLIC STAFF'S RECOMMENDATIONS?

A. The Public Staff's recommendations are based on a review of the Company's application, the testimony and exhibits of Company witnesses John Taylor and Byron Hinson, and, in particular, the Company's updated cost of service study (COSS) filed with Company witness Taylor's supplemental testimony as Exhibit 1. I also reviewed the Company's responses to pertinent Public Staff data requests.

Calculation of Class RORs and Assignment of Revenues

Q. HOW ARE RORS USED IN DETERMINING REVENUE ASSIGNMENT?

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

Q. PLEASE DISCUSS THE PUBLIC STAFF'S GOALS IN ASSIGNING CHANGES IN REVENUES.

A. The Public Staff believes that the assignment of a proposed revenue change, whether it is an increase or a decrease, should be governed by four fundamental principles. Using the ROR as determined by the COSS, and incorporating all adjustments and allocation factors associated with the proposed revenue change, the Public Staff seeks to:

1. Limit any revenue increase assigned to any customer class such that each class is assigned an increase that is no more than two percentage points

greater than the overall jurisdictional revenue percentage increase, thus avoiding rate shock;

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

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

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

Q. HAS THE PUBLIC STAFF APPLIED SIMILAR PRINCIPLES TO NATURAL GAS UTILITIES IN PREVIOUS RATE CASES?

A. No. These revenue assignment principles have not been applied to natural gas utilities in past general rate case proceedings. I reviewed the Company's last two general rate cases (Subs 495 and 565), including the final order and stipulations for each. Neither the stipulations nor the final orders addressed the issue of revenue assignment and RORs in a prominent way. I also did not observe any testimony filed by Intervenors representing industrial customers in those cases. My review of these documents did not indicate any material consideration of these principles in the stipulations or final orders. Similar disparities exist in this case.

Electric utility revenues and natural gas utility revenues are derived in different ways. “Sales” revenues are derived from customers who rely on the Company to secure the natural gas commodity and provide the facilities to distribute that natural gas to all customers at rates and pressures necessary to maintain an adequate level of service. “Transportation” revenues are derived from customers who secure the natural gas commodity on their own and use the Company’s transmission and distribution facilities to distribute the customer’s natural gas commodity to their respective points of delivery. Whether customers receive firm or interruptible service, or have special contracts that dictate their cost causation, each class of customers is responsible for its share of the costs to provide utility service. Those cost causation principles are typically determined through the cost functionalization, classification, and allocation processes that are associated with the Company’s COSS. This makes a COSS inextricably linked to the rate designs. Cost causation should be the first consideration when approving rates and rate designs. Once cost causation is established, then the Commission can apply its public policy objectives. While this process may result in a deviation from the Public Staff’s revenue assignment principles, both steps nevertheless conclude with a just and reasonable portfolio of rates.

Q. HOW DO THE RORS FOR THESE PAST GENERAL RATE CASES COMPARE TO THE PRESENT CASE?

A. Table 1 below summarizes the "per books" RORs from each case for each customer class that was part of that case. I used the "per books" values for the respective test year periods. This snapshot provides the best representation of the actual activities taking place in the test year.

Table No. 1 Comparison of Returns on Rate Base (%s)

Customer Classes	Sub 495	Sub 565	Sub 632
Residential	6.06	7.62	5.98
Small General Service	12.24	10.72	6.41
Medium General Service	Not included	Not included	10.35
Large General Service	17.79	5.89	1.96
Large General Service - Interruptible	11.07	5.74	0.33
Total Company	7.84	7.84	5.37

Source: See Paton Exhibit 5 for the Sub 495 and Sub 565 data. Taylor Supplemental Exhibit 1, page 7 of 226 in the present case. This exhibit is interpreted to represent the "per books" version of the cost of service study.

Q. IS THE PUBLIC STAFF MAKING A RECOMMENDATION ON THE ASSIGNMENT OF THE REVENUE REQUIREMENT TO THE NORTH CAROLINA CUSTOMER CLASSES?

A. The Public Staff intends to update its recommended jurisdictional revenue requirement and file supplemental testimony to provide its final recommended revenue change. I will provide the Public Staff's assignment of our proposed revenue change at that time.

Q. IF THE COMMISSION ORDERS A BASE REVENUE DECREASE IN THIS PROCEEDING, WHAT RECOMMENDATIONS DOES THE PUBLIC STAFF HAVE REGARDING THE ASSIGNMENT OF THE REVENUE DECREASE TO THE CUSTOMER CLASSES?

A. In the event of a base revenue decrease, I believe it is appropriate to focus on addressing any disparities in the class RORs. In addressing disparities in RORs, any revenue decreases assigned to individual customer classes should be limited so that no other customer class sees an increase in its assigned revenue requirement simply to address a disparity in RORs. In other words, in the event of a revenue requirement decrease, no customer class should see an increase simply to bring the class ROR within 10% of the jurisdictional ROR.

Whether there is an increase or decrease in base margin revenues, PSNC's customer classes exhibit significant differences in class

RORs. Because the process of bringing customer classes more in alignment may not be possible without creating significant rate shock to certain customer classes, strict adherence to the principles I outlined above may not be possible in this proceeding. Nevertheless, the process must begin at some level.

Rate Design

Q. PLEASE DISCUSS THE RELATIONSHIP BETWEEN A COSS AND RATE DESIGN.

A. Rate design should follow the same cost causation approach underlying the COSS, such that each customer class or customer is responsible for an appropriate share of the costs that are planned for and incurred in order to serve them, including both fixed and variable costs. However, strict adherence to this cost causation principle may not always be possible if doing so would result in “rate shock” for certain customers or customer classes. In addition, and depending on the COSS methodology utilized, cost responsibility results can vary significantly due to unusual events that occur in the test year. The COSS functionalizes costs, thus providing a basis from which to start rate design, but does not necessarily dictate the final rate design. Other considerations and objectives such as undue impacts on low-usage customers must also be considered when developing rate design.

The Company's revenue apportionment as proposed in its initial filing performs well in addressing the Public Staff's revenue apportionment principles except for the Large General Service classes. PSNC has proposed a 17% increase to respond to the low RORs for these classes. This level of increase far exceeds the Public Staff's definition of "rate shock" which limits any increase in rates assigned to any class by no more than two percentage points greater than the overall increase for the Company.

Q. DOES THE PUBLIC STAFF HAVE ANY ISSUES WITH THE COMPANY'S COSS IN THIS PROCEEDING?

A. Not for purposes of this proceeding. Due to constraints on time and resources, I was unable to complete a thorough review of the Company's COSS in this proceeding. Given the disparities in class RORs, the need to more fully understand the Company's calculations and applications of some of the allocation factors, and the degree to which interruptible customers and contract-related customers share in the recovery of fixed costs, I believe it is appropriate to conduct a deeper investigation into the COSS. I simply am not able to complete that study to my satisfaction in this case. Therefore, I do not oppose the use of the filed COSS in this proceeding. However, the Public Staff intends to work with the Company to achieve a fuller understanding of the COSS prior to the Company's next general rate case filing.

Q. WHAT SHOULD BE CONSIDERED WHEN ASSESSING THE DISPARITIES IN RATES OF RETURN FOR NATURAL GAS UTILITIES?

A. I believe there is a need to revisit the application of cost of service studies in rate design. The Commission's *Order on Remand* issued August 18, 1999, in Docket No. G-3, Sub 186,[1] has some bearing on this matter. The Commission cited four points about the application of a COSS to the setting of natural gas utility rates. First, cost of service studies are highly subjective in nature notwithstanding their appearance of mathematical certainty. Different studies typically produce different results. Thus, the Commission did not believe it was appropriate to adopt a specific study when setting rates. Second, the Commission has historically allowed higher RORs on industrial and commercial customer classes. The *Order on Remand* seems to suggest these higher returns on industrial and commercial customers is justified because the percentage of revenue being derived from non-residential customers is very small. Third, the Commission did not believe that rates should be based on cost alone. Other factors such as the ability to switch fuels (gas to electric), and the ability of some large customers to acquire their own natural gas and become "transportation" customers should be

---

[1] https://starw1.ncuc.net/NCUC/ViewFile.aspx?Id=ebae180f-b78b-4cb5-b67b-5f8e180497b6

considered. Fourth, the COSS methodology selected could affect the assignment of fixed gas costs to the classes. While there are similarities in the cost of service methods and calculations between electric and natural gas utilities, there may also be sufficient differences that continue to justify a different approach for each. Therefore, the Public Staff recommends that the Commission require the Company to address each of these revenue assignment principles in its next general rate case filing. The Commission should also require the Company to explain why any class ROR under proposed rates that falls outside of a band of reasonableness should be allowed going forward.

Q. ARE THERE ANY OTHER ISSUES RELATED TO THE COSS?

A. Yes. In reviewing the Company's COSS, it was difficult to discern the impacts in cost causation associated with contract customers, and large general service customers who are "sales" and "transportation" customers. First, the Company incorporates the revenue impacts associated with special contracts in its COSS by allocating those contract revenues to all other customer classes using an internal "total revenue requirement" allocation factor. This process has the overall effect of tempering the impact to the non-contract classes that would result from this rate increase. However, it also obfuscates the impacts related to the contracts as a class. In other words, the

Company's method of incorporating the impacts of special contracts in the COSS does not allow the Commission and other parties to see the individual impacts to expenses and rate base, and it does not allow a clear understanding of the ROR for the special contracts class. I recommend that future cost of service studies separate the special contracts into a separate class, and clearly identify the revenues, expenses, and rate base that would be associated with special contracts.

My second recommendation addresses the consolidation of the large general service "sales" and "transportation" customers into one class. As I observed in the recent Piedmont Natural Gas Company, Inc. general rate case (Docket No. G-9, Sub 781), large disparities can exist between sales and transportation customers, as well as firm and interruptible customers, when compared to other customer classes. In order to properly evaluate how each sub class (sales and transportation) is performing in relation to each other for both firm and interruptible large general service customers, I recommend that future cost of service studies distinguish between sales and transportation customers for each of the large general service customer classes.

<u>Affordability</u>

Q. PLEASE DISCUSS THE ISSUE OF AFFORDABILITY.

A. The issue of affordability was of substantial interest to the Commission and other parties in the Electric Dockets. The Commission issued final orders in the Electric Dockets[2] that required Duke Energy Carolinas, LLC, and Duke Energy Progress, LLC, (collectively the Duke Utilities) to convene a stakeholder process regarding affordability issues. The Commission directed that the collaborative should, as part of its work:

(1) Prepare an assessment of current affordability challenges facing residential customers. The assessment should:

a. Provide an analysis of demographics of residential customers, including number of members per household, types of households (single family or multi-family), the age and racial makeup of households, household income data, and other data that would describe the types of residential customers the Company now serves. To the extent demographics vary significantly across the Company's service area, provide additional analysis of these demographic clusters.

b. Estimate the number of customers who live in households with incomes at or less than 150% of the federal poverty guidelines (FPG), and those whose incomes are at or less than 200% of the FPG.

c. For the different demographic groups identified as part of a. and b., provide an analysis of patterns and trends concerning energy usage, disconnections for nonpayment, payment delinquency histories, and account write-offs due to uncollectibility.

[2] Dockets No. E-7, Subs 1213, 1214, and 1187, *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer Notice,* March 31, 2021 (DEC Rate Case Order); and Dockets No. E-2, Subs 1219 and 1193, *Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Customer* Notice, April 16, 2021 (DEP Rate Case Order).

(2) Develop suggested metrics or definitions for "affordability" in the context of the Company's provision of service in its North Carolina service territory and explore trends in affordability. Questions to be answered include but should not be limited to:

a. How is "affordability" defined and applied in other jurisdictions, particularly for those with similar legal and regulatory frameworks, i.e., vertically integrated investor-owned utilities?

b. What criteria (both qualitative and quantitative) should the Commission consider when determining who would be eligible for different types of affordability programs?

(3) Investigate the strengths and weaknesses of existing rates, rate design, billing practices, customer assistance programs and energy efficiency programs in addressing affordability. Questions that should be addressed include:

a. What defines a "successful program" and what metrics should be monitored and presented that show the impact of programs on addressing or mitigating affordability challenges?

b. What percentage of residential customers are eligible for each existing program and what percentage of eligible customers enroll in and/or take advantage of these programs?

c. What is the impact of existing programs on the energy burden for enrolled customers?

d. Should existing programs be maintained, replaced, or terminated? If maintained, should any changes be made to improve results? If programs are replaced, what would replace them?

e. Are the following programs, in addition to any others agreed upon by the collaborative, appropriate for implementation in North Carolina and, if so, what statutory or regulatory changes are necessary to permit implementation: (1) minimum bill concepts as a substitute for fixed monthly charges; (2) income-based rate plans, such as Ohio's percentage of income payment plan; (3) segmentation of the existing residential rate class to take into account different levels of usage; (4) expanding eligibility for DEC's current SSI-based program to include additional groups of ratepayers; and (5) the inclusion of a specific component in rates to be used to fund supplemental support programs. Priority should be given to identifying affordability programs that comply with the current statutory framework, however the collaborative may describe high potential programs that have been successful in other jurisdictions but which would require statutory changes for implementation in North Carolina.

f. How do specific programs addressing affordability affect cost- causation and allowance of costs among classes?

g. How does cost-of-service allocation affect rate design and affordability of rates?

h. What, if any, practices and regulatory provisions related to disconnections for nonpayment should be modified or revised?

i. What existing utility and external funding sources are available to address affordability? Estimate the level of resources that would be required to serve additional customers

j. What are the opportunities (and challenges) of the utilities working with other agencies and organizations to collaborate and coordinate delivery of programs that affect affordability concerns?

(DEC Rate Case Order at 176-78; DEP Rate Case Order at 186.)

While not an exhaustive list, the stakeholders were given wide latitude to develop their own objectives for addressing affordability. Periodic reports were required to inform the Commission of the progress being made with a goal of making final recommendations within 12 months.

Q. DOES THE SAME ISSUE OF AFFORDABILITY EXIST IN REGARDS TO NATURAL GAS UTILITY SERVICE?

A. Yes. The Public Staff does not see a distinctive difference in natural gas utility service and electric utility service when it comes to affordability matters. Energy burden encompasses both. The Public Staff believes that if consensus can be achieved among the electric utility stakeholders delving into affordability matters, there is a high likelihood that similar consensus can be achieved among natural gas utility stakeholders. Therefore, the Public Staff recommends that either a similar stakeholder process be convened for natural gas utilities or the Company be allowed to join the Duke Utilities' affordability stakeholder process. The initial meeting was held on July 29, 2021. This is a good time for the Company to become engaged in this process.

Q. DOES THE COMPANY'S APPLICATION FOR A GENERAL RATE CASE AND DIRECT TESTIMONY ADDRESS ANY OF THE AFFORDABILITY ISSUES YOU RAISED?

A. No. Unlike the two Duke electric cases, the Commission has not requested that this issue be addressed.

Q. WHAT IS YOUR RECOMMENDATION CONCERNING AFFORDABILITY?

A. The Public Staff recommends that the Commission consider many of the same issues of affordability for low-income residential customers it considered in the Electric Dockets, and issue an order either convening a stakeholder process separate from that involving the Duke Utilities, or alternatively, bring the Company into the same stakeholder process that is already underway.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

APPENDIX A

JACK L. FLOYD

I am a graduate of North Carolina State University with a Bachelor of Science Degree in Chemical Engineering. I am licensed in North Carolina as a Professional Engineer. I have more than 17 years of experience in the water and wastewater treatment field, nine of which were with the Public Staff's Water Division. In addition, I have been with the Energy Division for almost 18 years.

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

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

Currently, my duties with the Public Staff include evaluating the operation of regulated electric utilities, including rate design, cost-of-service, and demand side management and energy efficiency resources. My duties also include assisting in the preparation of reports to the North Carolina Utilities Commission; preparing testimony regarding my investigation activities; reviewing Integrated Resource Plans; and making recommendations to the Commission concerning the level of service for electric utilities.

MS. HOLT: I move that the prefiled testimony of John R. Hinton, consisting of 60 pages, including cover page and two appendices, be copied into the record as if given orally from the stand and that his 13 exhibits be identified as marked and entered into evidence.

COMMISSIONER BROWN-BLAND: All right. And you included his appendices?

MS. HOLT: Yes.

COMMISSIONER BROWN-BLAND: All right. Without objection, that motion is -- is allowed.

(Hinton Exhibits 1 through 13 were marked for identification and received into evidence.)

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

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

In the Matter of Application of Public Service Company of North Carolina, Inc., for a General Increase in Rates and Charges In the Matter of Application for Approval to Modify Existing Conservation Programs and Implement New Conservation Programs	))))))))))	TESTIMONY OF JOHN R. HINTON ON BEHALF OF THE PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

TESTIMONY OF JOHN R. HINTON

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 24, 2021

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

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

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

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

▼

practices for residential and commercial customers that involve customer contribution in aid of construction (CIAC) costs.

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

A. In the last PSNC general rate case (Docket No. G-5, Sub 565), the Commission approved an overall cost of capital of 7.53%, comprised of a capital structure ratio of 44.62% long-term debt at a cost rate of 5.52%, 3.38% short-term debt at a cost rate of 0.77%, and 52.00% common equity at a cost rate of 9.70%.

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

A. PSNC witness Spaulding's supplemental testimony updated the Company's requested overall cost of capital or rate of return to 7.59%. This rate of return is based on a capital structure consisting of 43.79% long-term debt at a cost rate of 4.48%, 1.33% short-term debt at a cost rate of 0.25%, and 54.88% common equity at a cost rate of 10.25% as noted in the testimony of Company witness Nelson.

Q. HOW DOES PSNC WITNESS NELSON DEVELOP HER RECOMMENDED 10.25% COST OF EQUITY?

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

Model (CAPM); and (3) the Risk Premium method. She applies these three methodologies to a proxy group of seven publicly traded natural gas distribution companies. Her first method relies on the Constant Growth DCF Model t and Quarterly Growth DCF model. The Constant Growth DCF model produces a range of estimates based on the average of the mean and median from 9.47% to 10.98% and the Quarterly Growth DCF produces a range of estimates from 9.63% to 11.14% as shown on Nelson Direct Exhibits 2 and 3. Ms. Nelson includes results from both a general form of the CAPM and an Empirical CAPM (ECAPM). The results of the general form CAPM range from 12.48% to 13.01% and the results of the ECAPM range from 12.95% to 13.34%. Witness Nelson's Risk Premium Model relies on a regression equation using approved returns on equity (ROE) with 30-year treasury yields to arrive at two cost of equity estimates of 9.75% and 9.86%. She also recommends that the cost of equity include an adder of 45 basis points to account for PSNC's small size. Based on the results of her cost of equity models and today's economic and financial environment, witness Nelson recommends a cost of equity range of 9.60% to 10.75%, with an ultimate recommendation of 10.25% cost rate for common equity.

▼

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

A. The Public Staff recommends an overall rate of return of 6.95%. This is based on a capital structure consisting of 47.71% long-term debt at a cost rate of 4.45%%, 1.39% short-term debt at a cost rate of 0.25%, and 50.90% common equity at a cost rate of 9.48%.

Q. HOW IS THE REMAINDER OF YOUR TESTIMONY STRUCTURED?

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

I. Legal and Economic Guidelines for Fair Rate of Return

II. Current Financial Market Conditions

III. Appropriate Capital Structure and Cost of Debt

IV. Cost of Common Equity Capital

V. Review of Nelson Testimony

VI. Summary and Recommendations for the Cost of Capital

VII. Revisions to the Gas Extension Feasibility Model

I. LEGAL AND ECONOMIC GUIDELINES FOR FAIR RATE OF RETURN

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

A. Public utilities possess certain characteristics of natural monopolies. For instance, it is more efficient for a single firm to provide a service such as natural gas utility service than for two or more firms to offer

▼

the same service in the same area. Therefore, regulatory bodies have assigned franchised territories to public utilities to provide services more efficiently and at a lower cost to consumers.

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

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

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

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

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties, but it has no constitutional right to profits such as are realized or anticipated in highly profitable enterprises or speculative ventures. The return should be reasonably

> sufficient to assure confidence in the financial soundness of the utility, and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally.

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

It is widely recognized that a public utility should be allowed a rate of return on capital that will allow the utility, under prudent management, to attract capital under the criteria or standards referenced by the

▼

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

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

> to produce a fair return for its shareholders, considering changing economic conditions and other factors . . . to maintain its facilities and services in accordance with the reasonable requirements of its customers in the territory covered by its franchise, and

▼

> to compete in the market for capital funds on terms that are reasonable and are fair to its customers and to its existing investors.

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

In considering this new element, the Commission is guided by ratemaking principles laid down by statute and interpreted by a body of North Carolina case law developed over many years. According to these principles, the test of a fair rate of return is an ROE that will provide a utility, under sound management, the opportunity to: (1) produce a fair profit for its shareholders in view of current economic

▼

conditions, (2) maintain its facilities and service, and (3) compete in the marketplace for capital. *State ex rel. Utils. Comm'n v. General Tel. Co.*, 281 N.C. 318, 370, 189 S.E.2d 705, 738 (1972). Rates should be set as low as reasonably possible consistent with constitutional constraints. *State ex rel. Utils. Comm'n v. Pub. Staff-North Carolina Utilities Com.*, 323 N.C. 481, 490, 374 S.E.2d 361, 366 (1988). The exercise of subjective judgment is a necessary part of setting an appropriate ROE. *Id*. Thus, in a particular case, the Commission must strike a balance that: (1) avoids setting a return so low that it impairs the utility's ability to attract capital, (2) avoids setting a return any higher than needed to raise capital on reasonable terms, and (3) considers the impact of changing economic conditions on consumers.

Q. WHAT IS A FAIR RATE OF RETURN?

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

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

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

II. <u>CURRENT FINANCIAL MARKET CONDITIONS</u>

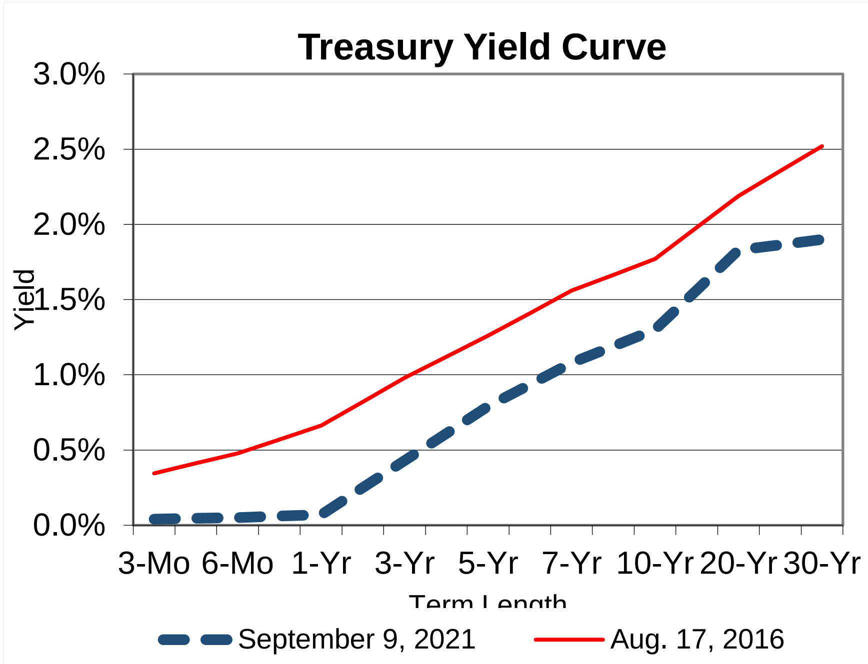
Q. CAN YOU BRIEFLY DESCRIBE CURRENT FINANCIAL MARKET CONDITIONS?

A. Yes. The cost of financing is much lower today than in the more inflationary period of the 1990s and the cost of debt capital has fallen since PSNC's last rate case in 2016. According to Mergent's <u>Bond Survey</u>, the yield on long-term "A" rated public utility bonds, as of August 2021 is 2.95% as compared to 3.77% observed for month-ending October 2016 (when the Public Staff was in settlement discussions with PSNC in Docket No. G-5, Sub 565). This suggests that the cost of debt capital is lower than it was at the time of PSNC's last general rate proceeding.

More recently, observed annual inflation rates have increased; the overall PCE Index (Personal Consumption Expenditure Index) jumped to 4.0% in June 2021 from 1.6 in February 2021. There have been similar increases in the CPI-U (Consumer Price Index – Urban). A key question today is whether these recent increases in inflation are predictors of future inflationary trends or temporary price changes caused by pent-up consumer demand and bottlenecks in the supply chain.[1] At this time, contemporaneous increases have yet to transpire in the utility bond market, as the increases in yields have been relatively minor as illustrated in Hinton Exhibit I. A-rated utility bond yields have fallen by 49 basis points from their high of 3.44% in March 2021 to 2.95% in August 2021. Since the Company's last general rate case in 2016, there have been declines in the long-end and short-ends of the yield curve shown below. [2]

[1] Alan S. Binder, "Don't Worry Too Much About the Inflation Surge," Wall Street Journal, July 7, 2021.

[2] Federal Reserve, H15 Selected Interest Rates, https://www.federalreserve.gov/releases/h15/



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

A. No. While I believe forecasts of earnings and dividends influence investor behavior, I generally do not believe interest rate forecasts are reliable in determining the cost of equity. Rather, I believe that current interest rates, especially in relation to yields on long-term bonds, are more appropriate for ratemaking. This is because it is reasonable to expect that as investors are pricing bonds, they are basing their expected inflation-adjusted return on current interest rates and future inflationary expectations among other factors. To suggest the current bond yields do not reflect expectations of future interest rate levels suggests that investors do not utilize projections of future interest rates in their decision-making or that the bond market is not efficient. I do not think either position is true.

While I am confident in the market's ability to reasonably weight forecasts of future interest rates, I am less confident in the appropriateness of using of interest rate forecasts for utility rate cases because I have seen numerous interest rate forecasts that do not materialize as expected. An example of this is the reliance, in part, of DEC's cost of capital witness Hevert in DEC's 2013 rate case, Docket No. E-7, Sub 1026, upon predicted 30-year treasury yields published by Blue Chip Financial Forecasts[3] for his CAPM and Risk Premium analyses. The December 1, 2012, Blue Chip Financial Forecasts predicted that the average 30-year treasury yields would rise to 5.5% by 2018. However, this long-term forecast was over 200 basis points higher than the actual average 30-year treasury yields observed for 2018. In DEC's 2017 rate case, Docket No. E-7, Sub 1146, witness Hevert used projected 30-year treasuries with a yield of 3.40%.[4] However, while the forecast errors associated with these projected 30-year treasury securities were smaller, this predicted yield for 2019 was

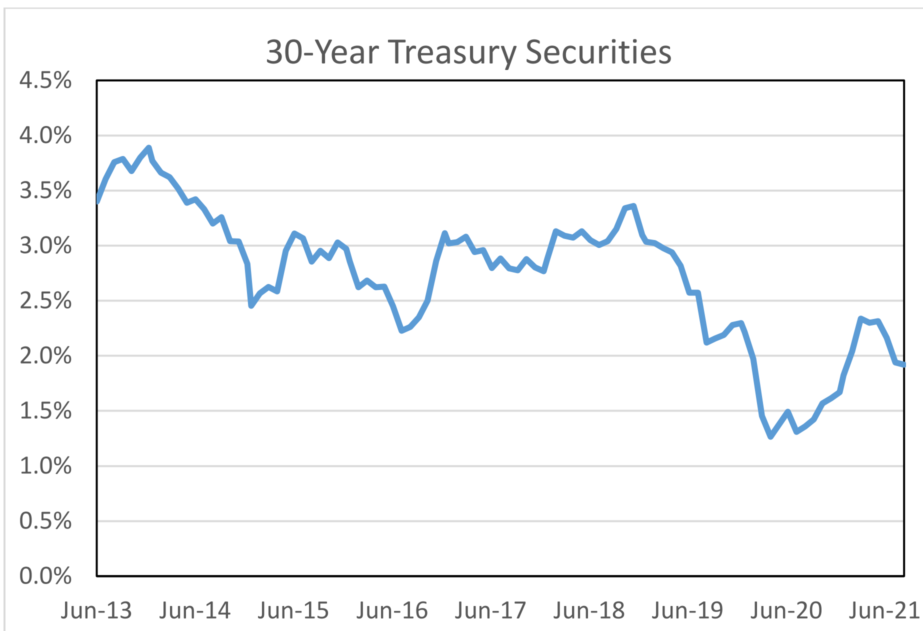
[3] The source of the forecast is noted, T vol. 2, 85-86, Docket No. E-7, Sub 1026.

[4] *See* Order Accepting Stipulation, Deciding Contested Issues, and Requiring Revenue Reduction, *Application of Duke Energy Carolinas, LLC, for Adjustment of Rates and Charges Applicable to Electric Utility Service in North Carolina*, Docket No. E-7, Sub 1146, at 39, (N.C.U.C. June 22, 2018), reversed on other grounds, *State ex rel. Utils. Comm'n v. Stein*, 375 N.C. 870, 851 S.E.2d 237 (2020).

▼

still over 140 basis points larger than the actual yields observed in 2019.

Another example is the interest rate prediction of Aqua North Carolina, Inc.'s (Aqua) rate of return witness Pauline Ahern in Aqua's 2013 rate case, Docket No. W-218, Sub 363.[5] Ms. Ahearn testified to several forecasts of 30-year Treasury bond yields that were predicted to rise to 4.3% in 2015, 4.7% in 2016, 5.2% in 2017, and 5.5% for 2020-2024.[6] As illustrated in the graph below, these forecasts significantly over-estimated the actual interest rates for 30-year Treasury bonds.



In addition, the tendency of economists to make overstated interest rate predictions in the last ten years was addressed in a December

[5] In 2013, Ms. Ahern was a Principal with AUS Consultants. She is currently Executive Advisor at ScottMadden, Inc.
[6] T vol. 2, 13-14, Docket No. W-218, Sub 363.

14, 2019, Wall Street Journal article entitled, "Economists Got the Decade All Wrong. They're Trying to Figure Out Why", and attached as Hinton Exhibit 2. The foregoing examples illustrate why I tend to place more weight on current market interest rates that are inherently forward-looking, as they reflect investor expectations of both current and future returns on bonds, and to an extent, future rates of inflation.

III. APPROPRIATE CAPITAL STRUCTURE AND COST OF DEBT

Q. FOR RATEMAKING, HOW DOES A COMPANY'S CAPITAL STRUCTURE IMPACT THE COST OF PROVIDING UTILITY SERVICES?

A. Typically, a local distribution company (LDC) obtains external capital from investors by borrowing debt and issuing common equity. However, PSNC obtains its equity capital from its parent company Dominion Energy Inc., (Dominion). The capital structure is simply a representation of how a utility's assets are financed. It is the relative proportions or ratios of debt and common equity to the total of these forms of capital.

Debt and equity capital have different costs. Common equity is far more expensive than debt for ratemaking purposes for two reasons. First, as mentioned earlier, there are income tax considerations. Interest on debt is deductible for purposes of calculating income taxes. The cost of common equity, on the other hand, must be "grossed up" to allow the utility sufficient revenue to pay income taxes and to earn its cost of common equity on a net or after-tax basis. Therefore, the amount of revenue the utility must collect from ratepayers to meet income tax obligations is directly related to both the common equity ratio in the capital structure and cost of common equity. A second reason for this cost difference is that the cost of common equity must be set at a marginal or current cost rate. Conversely, the cost of long-term debt is set at an embedded rate because the utility is incurring costs that were previously established in contracts with security holders.

Because the Commission has the duty to promote economical utility service, it must decide whether a utility's requested capital structure is appropriate for ratemaking purposes. An example of the cost difference between debt and equity can be seen in the Company's filing. Based upon the Company's requested capital cost rates, each dollar of its common equity and each dollar of its long-term debt that support the retail rate base have the following approximate annual costs (including income tax and regulatory fee expense) to ratepayers: each dollar of common equity costs ratepayers approximately 12 cents; and each dollar of long-term debt costs ratepayers approximately four cents.

▼

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

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

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

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

A. Company witnesses Phibbs and Nelson propose the use of a capital structure of 43.79% long-term debt, 1.33% short-term debt, and 54.88% common equity as shown on Spaulding Direct Exhibit 6 of the Company's Application. This proposal is derived by estimating the actual balances of long-term debt and common equity as of June 30, 2021, using a 13-month average balance of gas inventory as a proxy for short-term debt.

Q. DO YOU SUPPORT THE CAPITAL STRUCTURE PROPOSED BY THE COMPANY?

A. No. I have concerns with the use of a 54.88% common equity ratio in the proposed capital structure, which would provide an excessive percentage of equity that is not necessary to maintain the Company's credit ratings, and is not reflective of PSNC's historical capitalization ratio and its currently approved common equity ratio of 52.00%.

As of March 31, 2021, Moody's Investors Service, Inc.'s (Moody's) creditworthiness metric, Cash Flow from Operations (pre-working capital) divided by PSNC's debt yielded a 21.6 times, which is in alignment with Moody's expectations. Shown below are Moody's calculations of the Cash Flow metric and the Debt to Book

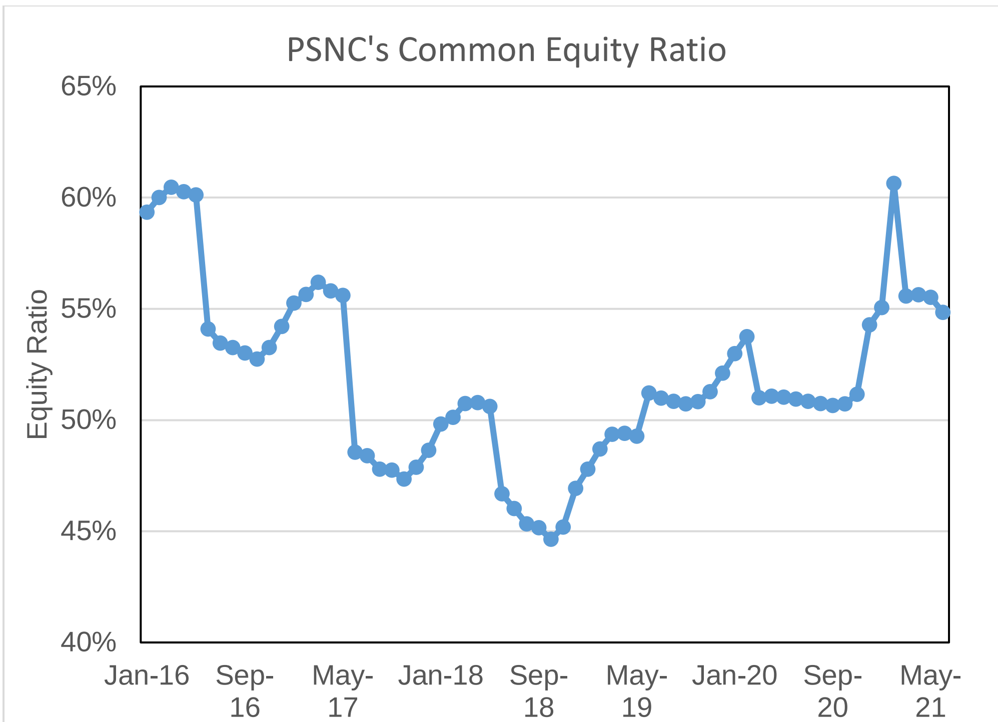
▼

Capitalization metric for PSNC, both of which include the Company's long-term and short-term debt balances.

Moody's Financial Scorecard	Cash Flow Pre-WC from Operations / Debt	Debt / Book Capitalization
Mar. 31, 2021	21.6%	39.9%
Dec. 31, 2020	14.3%	41.0%
Dec. 31, 2019	12.6%	43.1%
Dec. 31, 2018	12.1%	47.2%
Dec. 31, 2017	20.4%	44.0%

The fact that PSNC's Cash Flow metric has been both above and below 15%, a benchmark for Moody's, suggests that PSNC does not require a ratemaking structure with a 54.88% equity ratio; rather the approved 52.00% common equity ratio has adequately contributed to its ability to maintain its "Baa1" credit rating with a "Stable" outlook as reported in the Moody's Investors Service report in Hinton Exhibit 3.

Shown below is a graph of PSNC's common equity ratio since January 2016, which includes the period that SCANA Corp., which was the parent company of PSNC, merged with Dominion in January 2019. The graph illustrates that the Company's average balance of equity has hovered around 51.15%, and has averaged 51.97% since the 2019 merger. The spike in the equity ratio in February 2021 was due to paying off a current debt of $150 million, and financing the shortfall with over $200 million in notes payable (the largest amount recorded to date) in February, and then issuing a $150 million, 30-year bond at 3.10% the following month.



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

A. I typically recommend a capital structure for ratemaking purposes based on a 13-month historical average of long-term debt, short-term debt, and common equity; as of June 30, 2021, the Company's average capital structure contains 53.65% common equity as shown on Hinton Exhibit 4. Company witness Nelson argues that the

Company's request of a 54.88% common equity ratio is consistent with those reported to the Securities and Exchange Commission (SEC) by her group of comparable companies with a mean equity ratio of 52.90% and a median equity ratio of 55.26%, as shown in Nelson Direct Exhibit 8.

I recommend the use of a hypothetical capital structure containing 50.90% common equity based on the average capital structures approved in general rate cases for LDCs in 2020 and 2021[7] as reported by Standard and Poor's (S&P) Capital IQ[8] and shown on Hinton Exhibit 5. In my opinion, the use of an SEC-based reported capital structure can be misleading for regulatory applications as companies often have non-regulated operations and other concerns that are not necessarily appropriate for regulated utilities. As such, I maintain that the Company’s requested equity ratio is excessive, is inconsistent with current industry practices, and will lead to a higher cost of capital than is necessary for PSNC to maintain its credit rating and attract capital.

[7] General LDC rate cases from January 1, 2020, through September 8, 2021.

[8] S&P Capital IQ, Research, Past Rate Cases. Approved equity ratios do not include decisions from Arkansas, Florida, Indiana, and Michigan, which include non-capital balances. Data downloaded on September 11, 2021.

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

A. I recommend that the following capital structure be employed for ratemaking purposes in this proceeding based on a 50.90% common equity ratio, a 1.39% ratio of short-term debt that is based on the Public Staff's recommended balance of gas inventory, and a resulting 47.71% ratio of long-term debt.

PSNC Capital Structure

Thirteen-Month Average as of June 30, 2021

Capital Item	Amount	Ratios
Long-Term Debt	$ 836,814,487	47.71%
Short-Term Debt	24,429,174	1.39%
Common Equity	892,765,822	50.90%
Total Capital	$ 1,753,960,358	100.00%

Q. WHAT IS YOUR RECOMMENDED COST RATE OF SHORT-TERM DEBT?

A. For short-term debt, I accept the Company's proposed cost rate of 0.25%, as reasonable for this proceeding.

Q. WHAT IS YOUR RECOMMENDED COST RATE OF LONG-TERM DEBT?

A. With respect to long-term debt, the Company's June 30, 2021, embedded cost rate is 4.48%. However, I do not recommend that cost rate for this proceeding. On January 31, 2020, Moody's downgraded PSNC's long-term debt to Baa1 from A3 noting that one of its credit considerations was the impact of the rate freeze through November 2021 that was a condition of this Commission's approval of the merger of PSNC's parent company, SCANA, with Dominion.[9]

Another condition imposed by the Commission in its approval of the merger of SCANA and Dominion was that a replacement cost of debt would be imposed if the Company's debt were downgraded due to the merger.[10] The Company maintains that its 10-year, $200 million bond issued on March 30, 2020, was unaffected by the January 30, 2020 long-term debt rating downgrade by Moody's, despite the fact that the Moody's report noted that one of its considerations for downgrading PSNC was that the Company's financial profile was hurt by the merger conditions that involved a rate freeze through November 2021 and customer credits of $1.3 million provided annually in January of 2019, 2020, and 2021. PSNC's data responses on the impact of the downgrade stated that the private placement of this debt and the limited trading does not provide market data to show any real time impact of the downgrade. The Company noted that the National Association of Insurance Companies, S&P, and Fitch Ratings did not downgrade its debt rating. Furthermore, the Company noted that the emergence of

[9] *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, Docket No. E-22, Sub 551, Docket No. G-5, Sub 585, at 39 (November 19, 2018).

[10] *Order Approving Merger Subject to Regulatory Conditions and Code of Conduct*, Docket No. E-22, Sub 551, Docket No. G-5, Sub 585, Regulatory Condition No. 8.2 (November 19, 2018).

▼

COVID caused disruptions in the bond market that make the increase in the yield associated with the March 30, 2020 issuance not indicative of a stable market. Given the history of arguments made by utilities on the need for strong credit ratings that lead to lower costs of debt, I find PSNC's argument that the downgrade by Moody's had no impact on the prices offered by bond investors unpersuasive. Rather, I believe that bond investors attribute significant weight to Moody's reporting of credit risk and it is reasonable to believe that the that the downgrade impacted the prices offered by investors for the 10-year $200 million bond on March 20, 2020, and for the 30-year $150 million bond that was priced on February 11, 2021.

While I accept that there is difficulty in ascertaining the precise dollar impact in investors' pricing of the bonds and the subsequent increase in the yields, I believe that the increase in the yields with the post downgrade issues amounts to a ten basis point (bp) impact. I base the 10 bp estimate on the Company's response that indicated a possible five bp impact, a review of the 11 bp average spread between Mergent's[11] A-rated and Baa-rated yields from March 2020 through August 2021 shown below, as well as my previous investigations on the yield impacts of a one-notch downgrade by

[11] Mergent Bond Record, Mergent, Inc., September 2021.

Moody's for DEC and Duke Energy Progress, LLC.[12] As such, I recommend reducing the cost rate of each of the two subsequent debt issues by ten bp as a reasonable adjustment that is consistent with Regulatory Condition 8.2 that requires that PSNC's customers be held harmless from the impacts of a debt downgrade. The impact of the recommended ten bp reduction on the two debt issues of $200 million and $150 million issues reduces the embedded cost of debt from 4.48% to 4.45%.

Mergent Bond Record
Public Utility Bonds

	A-rated	Baa rated	Three-notch Spread	One-notch Spread
Mar-20	3.50%	3.96%	0.46%	0.15%
Apr-20	3.19%	3.82%	0.63%	0.21%
May-20	3.14%	3.63%	0.49%	0.16%
Jun-20	3.07%	3.44%	0.37%	0.12%
Jul-20	2.74%	3.09%	0.35%	0.12%
Aug-20	2.73%	3.06%	0.33%	0.11%
Sep-20	2.84%	3.17%	0.33%	0.11%
Oct-20	2.95%	3.27%	0.32%	0.11%
Nov-20	2.85%	3.17%	0.32%	0.11%
Dec-20	2.77%	3.05%	0.28%	0.09%
Jan-21	2.91%	3.18%	0.27%	0.09%
Feb-21	3.09%	3.37%	0.28%	0.09%
Mar-21	3.44%	3.72%	0.28%	0.09%
Apr-21	3.30%	3.57%	0.27%	0.09%
May-21	3.33%	3.58%	0.25%	0.08%
Jun-21	3.16%	3.41%	0.25%	0.08%
Jul-21	2.95%	3.20%	0.25%	0.08%
Aug-21	2.95%	3.19%	0.24%	0.08%
			Average	0.11%

[12] Docket Nos. E-7, Sub 1214, and E-2 Sub 1219.

IV. COST OF COMMON EQUITY CAPITAL

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

A. The cost of equity capital for a firm is the expected rate of return on common equity that investors require in order to induce them to purchase shares of the firm's common stock. The return is expected or forward-looking because the investor buys a share of the firm's common stock and does not know with certainty what his returns will be in the future. Furthermore, the cost of capital reflects opportunity costs in that the investor foregoes the opportunity to invest in other comparable risk investments.

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

A. I used the DCF model and a regression analysis of approved returns for LDCs and diversified gas companies with local distribution utilities to determine the cost of equity. As a check method, I performed a Comparable Earnings Analysis on my group of comparable companies.

A. DCF METHOD

Q. PLEASE DESCRIBE YOUR DCF ANALYSIS.

▼

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

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

g = expected growth rate of dividends;

k = cost of equity capital; and

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

Then,

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

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

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

Solving for k yields the DCF equation:

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

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

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

A. Since PSNC is a wholly owned subsidiary of Dominion, the Company does not have any publicly traded stock. Therefore, there is no explicit market information to show what investors would pay for the stock. For this reason, I could not apply the DCF method directly to PSNC. However, the cost of equity capital is not unique to any particular firm. Rather, it is a cost shared by firms whose equity shares are considered by investors to be risk-comparable investments. In order to estimate the required rate of return, I have identified a group of comparable companies whose market information indicates the required investor return for PSNC.

▼

Q. HOW DID YOU IDENTIFY COMPANIES COMPARABLE IN RISK TO PSNC?

A. I began my analysis by reviewing ten companies that are identified by the Value Line Investment Survey Standard Edition (Value Line) as the Natural Gas Company industry group. From this group of companies, I eliminated Nisource, Inc., due to a dividend cut in 2015. I then reviewed the diversified natural gas companies followed by Value Line and found two companies that were identified as having distribution operations.

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

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

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

I also reviewed the S&P and Moody's bond ratings, which are assessments of the creditworthiness of a company. Credit rating agencies focus on the creditworthiness of the particular bond issuer, and conduct a detailed and thorough review of the potential areas of business risk and financial risk of the company. These and other risk measures I reviewed are shown in Hinton Exhibit 6 and are further explained in Appendix B to my testimony.

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

A. I calculated the dividend yield by using the Value Line estimate of dividends to be declared over the next 12 months, divided by the price of the stock as reported in the Value Line Summary and Index for each week of the 13-week period from June 18, 2021, through September 10, 2021. A 13-week averaging period tends to smooth out short-term variations in the stock prices. This process resulted in an average dividend yield of 3.3% for the comparable group of LDCs.

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

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

Finally, I incorporated the consensus of various analysts' forecasts of five-year EPS growth rate projections as reported in Yahoo Finance and three-year projected growth rate EPS forecast by CFRA. The dividend yields and growth rates for each of the companies and for the average for the comparable group are shown in Hinton Exhibit 7.

▼

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

A. Based on my DCF analysis, I determined that a reasonable expected dividend yield is 3.3%, with an expected growth rate of 5.9% to 6.5%. As such, the analysis produces a cost of common equity range for the comparable group of LDCs of 9.15% to 9.84%.

B. <u>REGRESSION ANALYSIS METHOD</u>

Q. PLEASE DESCRIBE YOUR REGRESSION ANALYSIS METHOD.

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

A strength of this approach is that authorized returns on equity are generally arrived at through lengthy investigations by various parties with opposing views on the rate of return required by investors. Thus, it is reasonable to conclude that the approved returns are good estimates for the cost of equity. The next step is to incorporate a contemporaneous cost of debt. I then use an ordinary least-squares regression model[13] that can be performed with spreadsheets that have basic statistical functionality.

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

A. The method I used relies on approved returns on common equity for natural gas utility companies from various public utility commissions that are published by the Regulatory Research Associates, Inc. (RRA), with S&P Global Market Intelligence and Moody's "A" rated Utility Bond Yields as shown on Page 1 of Hinton Exhibit 8. The results from the regression analysis in this study and in other studies indicate that there is a high correlation between the cost of equity and utility bond yields.[14]

Q. WHAT ARE THE RESULTS OF YOUR REGRESSION ANALYSIS?

A. The results of the regression analysis indicate that the predicted cost of equity is 9.49% as shown on Page 2 of Hinton Exhibit 8. As noted, a statistical regression was performed in order to quantify the

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

[14] *See* Brigham, E., Shome, D., and Vinson, S., 1985. "The Risk Premium Approach to Measuring a Utility's Cost of Equity." Financial Management, Spring 14: 33-45.

relationship of allowed equity returns and bond costs. The results of the regression analysis indicate a significant statistical relationship between the approved equity returns and bond costs such that a reduction of 10 bp in yields corresponds to a decrease of three bp in ROE.[15] Therefore, the regression analysis allows the historical relationship of approved returns on equity and bond yields from 2007 through 2021 to be quantified and combined with six months of recent yields to derive a predicted 9.49% cost rate for common equity.

C. COMPARABLE EARNINGS METHOD

Q. PLEASE DESCRIBE YOUR COMPARABLE EARNINGS ANALYSIS THAT YOU USE AS A CHECK.

A. My comparable earnings method analysis involves reviewing earned returns on equity for my comparable group of natural gas utilities. This approach is based on the decision in the *Hope* case cited earlier in my testimony, which maintains that an investor should be able to earn a return comparable to the returns available on alternative investments with similar risks.

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

[15] The regression equation ROE = 0.0867872 + 0..25424504*3.19%, indicates a significant statistical relationship between Moody's utility bond yields and approved ROEs with an adjusted R^2 = 0.8593500.

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

Q. HOW DID YOU APPLY THE COMPARABLE EARNINGS METHOD?

A. I examined the historical earned returns and near-term predicted returns of my comparable group of LDCs as reported in Value Line, as shown in Hinton Exhibit 9.

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

A. Based on the earned rates of return, I conclude that the cost of equity calculated using the Comparable Earnings analysis provides a reasonable check on my DCF and Regression Analysis results. Under the Comparable Earnings method, I calculated an average historical earned return of 10.0% and a median earned return of 9.5%. In my opinion, the median calculation is a better measure of central tendency due to inclusion in the mean calculation of the 20.2% earned return of National Fuel Gas and other excessively high-earned returns. As such, I believe the median earned return of 9.5% is more reflective of investors' expected required ROEs.

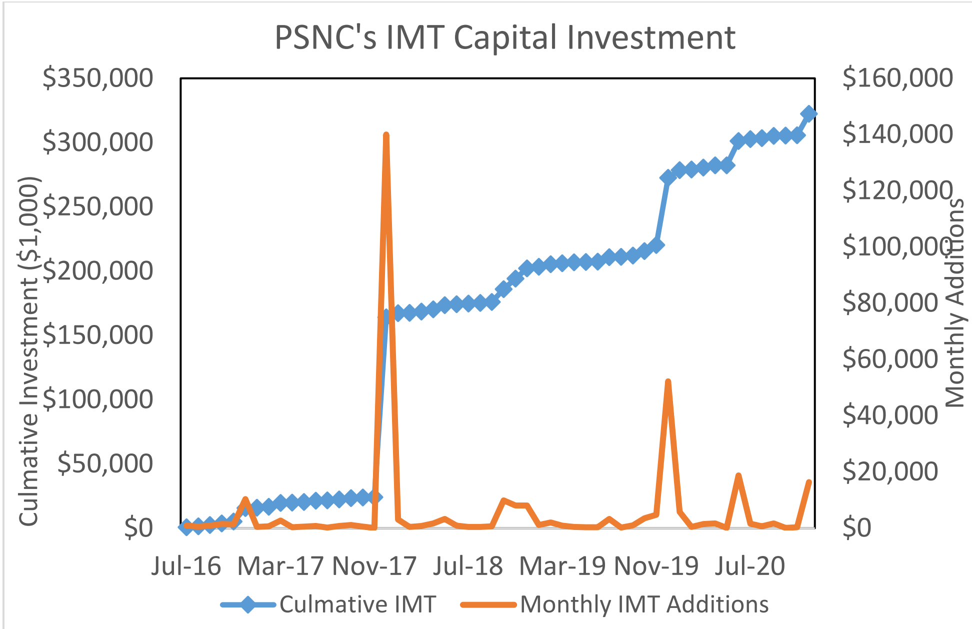
Q. WHAT IS YOUR RECOMMENDED COST OF EQUITY FOR THE COMPANY BASED ON YOUR OVERALL STUDY?

A. I recommend a 9.48% cost rate for common equity, as shown in Hinton Exhibit 10, where I average the four results of my two methods. The results of my DCF model produce a cost of equity of 9.20% using historical growth rates. If I assume that investors equally weigh historical growth and forecasts, the DCF model produces a 9.44% cost rate of equity. If I assume investors use only predicted growth rates of earnings, dividends, and book value, the DCF model produces a 9.84% cost rate. I combined these three DCF results with my Regression Analysis result of 9.49% to yield an average cost of equity of 9.48%, which is my recommended cost of common equity for the Company.

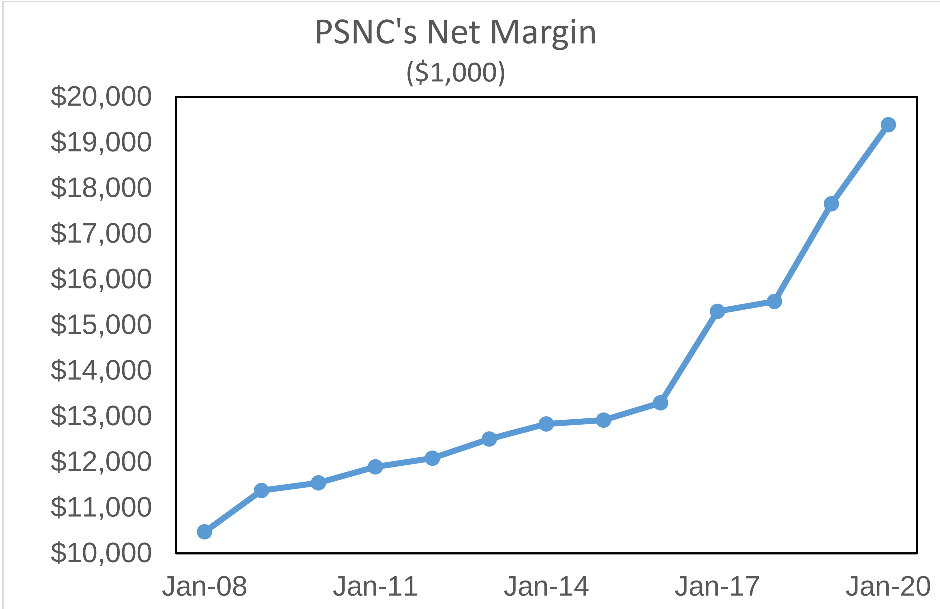
Q. WHAT OTHER EVIDENCE DID YOU CONSIDER IN YOUR ASSESMENT OF THE REASONABLENESS OF YOUR RECOMMENDED RETURN?

A. In assessing the reasonableness of my recommendation, I considered the pre-tax interest coverage ratio produced by my cost of capital recommendation. Based on the recommended capital structure, cost of debt, and cost of equity, the pre-tax interest coverage ratio is approximately 3.9, as shown on Hinton Exhibit 13. This indicator of credit quality suggests that PSNC has an adequate opportunity to continue to qualify for a "Baa1" bond rating.

My reasonableness assessment also factors in the role that the Integrity Management Tracker (IMT) has in reducing regulatory lag, which is seen as a supportive regulatory policy by investors. The graph below shows the additional monthly plant additions associated with the Company's IMT mechanism, which as of December, 2020, amounted to approximately $322 million of additional capital investment since the tracker was implemented in July 2016.



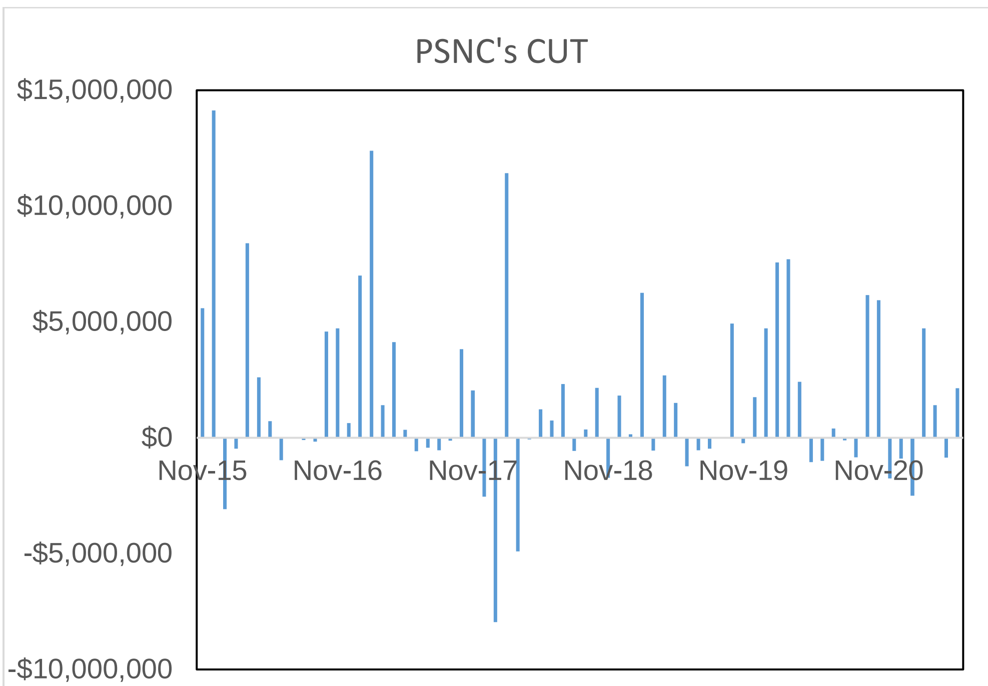
As noted, the IMT has alleviated some of the concerns about regulatory lag by allowing the Company to periodically increase its rate base without filing for a general rate case. Monthly financial data from the Company's G.S.-1 reveal that the annual compound growth rate of the Company's annual margins has significantly increased under the IMT. From 2016 to 2020, net margins have increased at an annual rate of 9.9% as compared to a 2.4% annual growth rate from 2012 to 2016. The graph below reflects the Company's net margin calculated by deducting the cost of gas and its O&M expense from its operating revenues.



In addition, I also considered the stabilizing impact on residential and small commercial customers' revenue and on the Company's earnings under the Customer Utilization Tracker (CUT) that was approved by the Commission in 2008 in Docket No. G-5, Sub 495.[16,] In large part, the tracker was approved in light of declining customer usage and as a way to eliminate the Company's disincentive to promote conservation and better align the interests of the Company and its customers. The Commission's Order noted that the CUT protects customers from an overcollection of margin revenues to the same degree that it protects the Company from an undercollection of margin revenues. The Commission stated that the CUT would stabilize the Company's margin recovery and reduce the risk to

[16] Order Approving Partial Rate Increase and Requiring Conservation Program Filing and Reporting, *In the Matter of Application of PSNC, Inc., for a General Increase in its Rates and Charges*, Docket No. G-5, Sub 495 (N.C.U.C. Oct. 28, 2008) (Sub 495 Order).

PSNC and its customers arising from potential variations in usage patterns.[17] The graph below shows the historical impact of the revenue adjustments associated with the CUT. The IMT leads to less regulatory lag, which lessens PSNC's financial risk, while the CUT significantly reduces PSNC's business risks. For the 12 months ending June 30, 2021, the CUT resulted in residential rate schedules 101 and 102 owing the Company an additional $10.5 million and small general service rate schedules 125,127, and 140 owing the Company $2.8 million.



[17] *See* Sub 495 Order, Finding of Fact No. 24, at 22-23. The CUT affects rate schedules 101, 102, 125, and 127.

Q. TO WHAT EXTENT DOES YOUR RECOMMENDED ROE TAKE INTO CONSIDERATION THE IMPACT OF CHANGING ECONOMIC CONDITIONS ON PSNC'S CUSTOMERS?

A. I am aware of no clear numerical basis for quantifying the impact of changing economic conditions on customers in determining an appropriate ROE in setting rates for a public utility. Rather, the impact of changing economic conditions nationwide is inherent in the methods and data used in my study to determine the cost of equity for utilities that are comparable to PSNC. I have reviewed certain information on the economic conditions in the areas served by PSNC, specifically data on the per capita personal income from the Bureau of Economic Analysis (BEA) and the Development Tier Designations published by the North Carolina Department of Commerce for PSNC's service territory. The BEA data indicate that from 2017 to 2019, per capita total personal income grew at an annual growth rate of 3.5%, which is slightly lower than the 3.7% growth rate for the whole state. While more current income data by county is not available, the statewide total personal income grew at an 18% annual growth rate as of the first quarter of 2021.[18] In addition, North Carolina's unemployment rate has fallen for the eleventh consecutive month to 4.3%[19] in August 2021.

[18] BEA, Table 1, Personal Income by State and Region, 2019: Q4-2021:Q1.

[19] https://www.nccommerce.com/news/press-releases/north-carolina%E2%80%99s-august-employment-figures-released-1

The North Carolina Department of Commerce annually ranks the State's 100 counties based on economic well-being and assigns each a Tier designation. The most distressed counties are rated a "1," and the most prosperous counties are rated a "3." The rankings examine several economic measures such as household income, poverty rates, unemployment rates, population growth, and per capita property tax base. For 2021, the average Tier ranking for North Carolina counties in PSNC's service territory was 2.0, which is above the statewide Tier average of 1.8.[20.]

As discussed previously, the Commission's duty is to set rates as low as reasonably possible consistent with constitutional constraints. This duty exists regardless of the customers' ability to pay. Moreover, the rate of return on common equity is only one component of the rates established by the Commission. General Statute § 62-133 sets out an intricate formula for the Commission to follow in determining a utility's overall revenue requirement. It is the combination of rate base, expenses, capital structure, and cost rates for debt and equity capital, that determines how much customers pay for utility service and investors receive in return for their investment. The Commission must exercise its best judgment in balancing the interests of both groups. My analysis of the income data and the tier rankings

[20] NC Department of Commerce, 2021 North Carolina Development Tier Designations, November 2020.

indicates that economic conditions are not unduly burdensome for PSNC's customers. As shown in the income and unemployment data, overall economic conditions have significantly improved from the height of the pandemic. While this is applicable to most of the State and PSNC's customers, it is true that the economic wellbeing of certain customers and related businesses will take years to recover from the COVID-19 pandemic. Nonetheless, I maintain that my recommended ROE will allow the Company to properly maintain its facilities, provide adequate service to its customers, attract capital on terms that are fair and reasonable to its customers and investors, and result in rates that are just and reasonable.

V. REVIEW OF NELSON TESTIMONY

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

A. Yes. My review indicates that her analyses include several inputs with which I take issue, and which I believe lead to a higher than appropriate recommended rate of return. In particular, I disagree with her exclusive use of forecasted EPS in the DCF model, her estimate of the expected market return, and the market premium used in her CAPM.

Q. WHY DO YOU DISAGREE WITH COMPANY WITNESS NELSON'S EXCLUSIVE USE OF FORECASTED EPS IN HER DCF ANALYSIS?

A. Company witness Nelson has focused entirely on five-year EPS forecasted growth rates in estimating the long-term expected growth rate in DPS for purposes of her DCF model. She has not given any weight to either historical EPS growth rates or historical and forecasted DPS and BPS growth rates. While I have given primary weight to forecasted growth rates of EPS, DPS, and BPS, I have also accorded some weight to actual historical performance in my recommendation. Consideration of DPS and BPS, along with EPS, provides a variety of indicative growth measures, as opposed to Ms. Nelson's reliance on only one measure. Given that at least one study has found that analysts' long-term earnings growth forecasts are no more accurate at forecasting future earnings than "random walk" forecasts of future earnings,[21] and that other studies have found that analyst's earnings forecasts tend to have an upward bias in their projections, I find the premise that investors limit their investment decisions to forecasted growth rates in EPS to be quite questionable. Company witness Nelson's DCF analysis is flawed because investors do not simply ignore the historical performance of stocks.

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

While forecasts are generally based, in part, on a company's historical performance, it is quite a different argument to state that investors rely solely on forecasts of EPS and ignore past performance of dividends and book value.

In prior orders, this Commission has not been persuaded by rate of return witnesses who relied exclusively on forecasted growth rates in their use of the DCF model. In its Order in Docket No. E-22, Sub 532, the Commission said, "as stated in previous Commission general rate case orders, [the Commission] does not approve of witness Hevert's sole use of analysts' predicted earnings per share to determine the DCF growth rate".[22] Similarly, in its Order issued on December 30, 2003, in Docket No. P-100, Sub 133d, the Commission said, "The Commission is persuaded that investors consider a company's historical performance along with its forecasts when assessing its long-run growth potential."[23] In that proceeding, BellSouth's witness Billingsley gave exclusive weight to security analysts' EPS forecasts compiled by Zacks Investment Research and the Institutional Brokers Estimate System, which is comparable to witness Nelson's

[22] *In the Matter of Application of Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina,* Order Accepting Public Staff Stipulation in Part, Accepting CIGFUR Stipulation, Deciding Contested Issues, and Granting Partial Rate Increase, (N.C.U.C. February 24, 2020) (*appeal filed on other grounds*) at 40.

[23] *In the Matter of General Proceeding to Determine Permanent Pricing for Unbundled Network Elements,* Order Adopting Permanent Unbundled Network Element Rates for Bellsouth Telecommunications, Inc., Docket No. P-100, Sub 133d (N.C.U.C. Dec. 30, 2003) at 73.

▼

use of earnings forecasts. This reliance on only forecasted growth is incorporated into her DCF model and her CAPM's use of a market risk premium that relies on results from her DCF model applied to the companies in the S&P 500.

Q. WHY DO YOU DISAGREE WITH COMPANY WITNESS NELSON'S USE OF THE QUARTERLY DCF MODEL?

A. I do not support the use of the quarterly DCF model given that it reflects a cost of capital that is above the required rate of return by investors. In that, this Commission has established that it is unnecessary for ratepayers to provide for that added or incremental return associated with the quarterly payment of dividends they receive. In several previous electric and telephone cases, the Commission has rejected the quarterly DCF model.[24.]

Q. PLEASE EXPLAIN YOUR CONCERNS WITH COMPANY WITNESS NELSON'S ESTIMATE OF THE EXPECTED MARKET

[24] *See In the Matter of Application by Carolina Power & Light Company for Authority to Adjust and Increase Its Rates and Charges,* Order Granting Partial Increase in Rates and Charges, Docket No. E-2, Sub 537 at 187-91, (N.C.U.C. August 5, 1988), (*affirmed in part, reversed in part, and remanded for future consideration on other grounds*); *In the Matter of Application of Citizens--Telephone Company for Authority to Adjust its Rates and Charges for Intrastate Telephone Service*, Order Granting Partial Rate Increase at 662, Docket No. P-12, Sub 89 (N.C.U.C. February 26, 1991); *In the Matter of General Proceeding to Determine Permanent Pricing for Unbundled Network Elements*, Order Adopting Permanent Network Element Rates for BellSouth Telecommunications, Inc., Docket No. P-100, Sub 133d at 70-71, (N.C.U.C. December 30, 2003); *In the Matter of General Proceeding to Determine Permanent Pricing for Unbundled Network Elements*, Order on Impact of TRO on Cost of Capital and Depreciation Rate Inputs for the UNE Rates of BellSouth, Carolina, Central, and Verizon, (N.C.U.C. July 9, 2004).

RISK RETURN AND MARKET PREMIUM INCORPORATED IN HER CAPM.

A. Company witness Nelson's CAPM model based on her Total Market Approach assumes that investors are currently requiring expected risk premiums of 12.37% and 11.62% that are based on an investor expected return of 14.34% as shown on page 7 of Nelson Direct Exhibit 4.

In my opinion, Company witness Nelson's estimate of the expected returns on the S&P 500 of 14.34% using Value Line's growth rates, much less the estimate of 16.35% using Bloomberg's growth rates, are unrealistic for investors over the long run. These returns inflate her market premium and her CAPM and ECAPM cost of equity estimates. It is highly unlikely that over the long run the growth of the S&P 500 would exceed the growth of the general economy. As such, I maintain that Ms. Nelson's expected growth rates for the S&P 500 are unsustainable and not appropriate for utility ratemaking.

Q. WHAT DO WELL KNOWN INVESTMENT ADVISORS BELIEVE THE FUTURE RATES OF RETURNS WILL BE FOR THE S&P 500?

A. As shown in Hinton Exhibit 11, Christine Benz of Morningstar has collected forecasts of long-term rate of returns on stocks and bonds by BlackRock Investment Institute, as well as investment professionals John Bogle with Vanguard and J.P. Morgan. In general, they expect a departure from history with lower future market returns on equity of 5% to 8%. In a recent article attached as Hinton Exhibit 12, Veeru Perianan, Director, Multi-Asset Research, Charles Schwab Investment Advisory, Inc., predicts that the annualized returns on large capitalized stocks over the next ten years will be 6.6% as compared to the 10.8% historical return experienced since 1970.

VI. <u>SUMMARY AND RECOMENDATIONS FOR THE COST OF CAPITAL</u>

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

A. Based on the results of my analysis and study, I recommend that the appropriate overall cost of capital in this case be set at 6.95% as shown on Hinton Exhibit 13. This recommendation is derived based on a capital structure consisting of 47.71% long-term debt with a cost rate of 4.45%, 1.39% short-term debt with a cost rate of 0.25%, and 50.90% common equity, with a recommended cost rate of 9.48%.

VII. <u>REVISIONS TO THE GAS EXTENSION FEASIBILTY MODEL</u>

Q. PLEASE DISCUSS THE COMPANY'S MODEL USED TO CALCULATE THE FEASIBILITY OF EXTENDING NATURAL GAS SERVICE TO ITS RESIDENTIAL AND COMMERCIAL CUSTOMERS.

A, The Company calculates the economic feasibility of providing new gas service to existing structures by estimating the costs for the connection beyond the allowed 100 feet of main line and 100 feet of service line offset by the cash flows generated by the expected gas margins associated with the customer's expected gas usage. The feasibility study follows capital budgeting practices. The model involves the projection of the after tax cash flows over the next 20 years to derive at a net present value (NPV) and an internal rate of return (IRR). If the project has a positive present value, then the customer does not have to make a contribution in aid of construction (CIAC); however, where the costs to connect are greater than the NPV, there is a CIAC requirement. Pursuant to Commission Rule 7-16 (b)(1), the Company provides 100 feet of main line and 100 feet of service line to new customers with existing structures; however, PSNC does not provided a similar cost allowance to new customers with new housing structures, such as with a proposed new residential subdivision. PSNC maintains that extending service to new subdivisions may require additional capital expenditures beyond the expected revenues generated that may not be representative of the cost of service.

Q. PLEASE ADDRESS YOUR CONCERNS WITH THE COMPANY'S MODEL.

A. My first three concerns are based on the Company's the Commission's NPV Guidelines approved on August 4, 1999, in Docket No. G-100, Sub 75. These Guidelines were applied to projects to extend natural gas service to various unserved counties such as McDowell County in Docket No. G-5, Sub 337, Alexander County in Docket No. G-5, Sub 391, and Onslow County in Docket G-21, Sub 330. Under the Guidelines, the appropriate investment horizon is 40 years. Thus in this case, I recommend the use of 40 years or an appropriate length of time that matches the book lives of the gas plant. Second, the Guidelines directed the use of the approved net of tax discount rate employed for the NPV analysis. Third, the Guidelines required that all future cash flows be adjusted by a forecasted long-term inflation rate. The Company's current feasibility model assumes that the margins remain static over the 20-year investment horizon. As such, I recommend that the gas margins associated with the customer's gas usage be adjusted for expected inflation. At this time, I recommend the use of a 2.0% long-term inflation rate for all gas flows that generally include gas margins and operating and maintenance (O&M) expense.

My fourth concern is with the Company's 100-foot allowance for main extensions and 100-foot allowance of service extension for new customers in new structures or subdivisions. The Public Staff does not believe that there is justification for discriminating between existing and new housing structures. The Public Staff shares the Company's concern with cost; however, in cases that involve substantial additional capital, the Company could file for an exception to the rule as opposed to having Company-wide policy that presumes that all new customers in new subdivisions generate unreasonable costs to connect even when located within the 100-foot allowances.

Q. WHAT IS THE BASIS FOR A 2% LONG-TERM INFLATION RATE?

A. While the rate is slightly below the long-term inflation rates that have been employed in recent nuclear decommissioning and electric utility integrated resource planning proceedings, I believe it is a reasonable rate for this application where future O&M expenses and margins are inflated over the next 40 years. Furthermore, it is my understanding that a similar inflation rate has been applied to O&M expenses for the provision of gas service to DEC's combustion turbine in Lincoln County, North Carolina and other gas expansion analyses reviewed by the Public Staff.[25]

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[25] Docket Nos. G-9, Sub 750 and G-9, Sub 720.

▼

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

JOHN ROBERT HINTON

I received a Bachelor of Science degree in Economics from the University of North Carolina at Wilmington in 1980 and a Master of Economics degree from North Carolina State University in 1983. I joined the Public Staff in May of 1985. I filed testimony on the long-range electrical forecast in Docket No. E-100, Sub 50. In 1986, 1989, and 1992, I developed the long-range forecasts of peak demand for electricity in North Carolina. I filed testimony on electricity weather normalization in Docket Nos. E-7, Sub 620, E-2, Sub 833, and E-7, Sub 989. I filed testimony on customer growth and the level of funding for nuclear decommissioning costs in Docket No. E-2, Sub 1023, Docket No. E-2, Sub 1219, and similar proceedings on the level of funding for nuclear decommissioning costs in Docket Nos. E-7, Sub 1026, and E-7, Sub 1146. I have filed testimony on the Integrated Resource Plans (IRPs) filed in Docket No. E-100, Subs 114 and 125, and I have reviewed numerous peak demand and energy sales forecasts and resource expansion plans filed in electric utilities' IRPs

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

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

I have filed testimony on the issue of fair rate of return for electric utilities in Docket Nos. E-22, Sub 333; E-22, Sub 412; and E-22, Sub 532. I have filed testimony on credit metrics and the risk of a downgrade in Docket No. E-7, Sub 1146. I have filed testimony on the rate of return for telephone utilities in P-26, Sub 93; P-12, Sub 89; P-31, Sub 125; P-100, Sub 133b; and P-100, Sub 133d (1997 and 2002); the rate of return for natural gas utilities in G-21, Sub 293; G-21, Sub 442; G-5, Sub 327; G-5, Sub 386; G-9, Sub 351; G-9, Sub 743; G-9, Sub 781; and the rate of return for water utilities in W-778, Sub 31; W-218, Sub 319; W-218, Sub 497; W-218, Sub 526; W-354, Sub 360, W-354, Sub 364, and in several smaller water utility rate cases.

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

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

RISK MEASURES

SAFETY RANK[1]

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

BETA[1] (ß)

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

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

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

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

$$\text{Adjusted } ß_i = 0.35 + 0.67ß$$

FINANCIAL STRENGTH RATING[1]

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

PRICE STABILITY INDEX[1]

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

EARNINGS PREDICTABILITY INDEX[1]

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

S&P BETA[2] (ß)

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

S&P BOND RATING[2]

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

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

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

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

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

S&P STOCK RANKING[2]

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

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

Moody's Bond Rating[3]

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

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

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

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

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

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

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

Sources:
1. Value Line Investment Analyzer, Version 3.7.0.15, New York, NY.
2. S&P Net Advantage and S&P Global Market Intelligence, July, 2019
3. Moody's Investor Service, Rating Symbols and Definitions, February, 2019

MS. HOLT: I move that the prefiled testimony of Roxie McCullar, consisting of 25 pages, be copied into the record as if given orally from the stand and that her six (6) exhibits be identified as marked and entered into evidence.

COMMISSIONER BROWN-BLAND: All right. Hearing no objection, motion is allowed.

(McCullar Exhibits 1 through 6 were marked for identification and received into evidence.)

(Whereupon, the prefiled direct testimony of Roxie McCullar was copied into the record as if given from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

DOCKET NO. G-5, SUB 632 In the Matter of Application of Public Service Company of North Carolina, Inc., for a General Increase in Rates and Charges DOCKET NO. G-5, SUB 634 In the Matter of Application for Approval to Modify Existing Conservation Programs and Implement New Conservation Programs	)	TESTIMONY OF ROXIE MCCULLAR PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

Table of Contents

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

TESTIMONY OF ROXIE MCCULLAR

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 23, 2021

I. Introduction

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Roxie McCullar. My business address is 8625 Farmington Cemetery Road, Pleasant Plains, Illinois 62677.

Q. WHAT IS YOUR PRESENT OCCUPATION?

A. Since 1997, I have been employed as a consultant with the firm of William Dunkel and Associates and have regularly provided consulting services in regulatory proceedings throughout the country.

Q. PLEASE DESCRIBE YOUR EDUCATIONAL AND PROFESSIONAL BACKGROUND.

A. I have 20 years of experience consulting in regulatory rate cases and have addressed depreciation rate issues in numerous jurisdictions nationwide. I am a Certified Public Accountant licensed in the state of Illinois. I am a Certified Depreciation Professional through the Society of Depreciation Professionals. I received my Master of Arts degree in Accounting from the University of Illinois in Springfield. I received my Bachelor of Science degree in Mathematics from Illinois State University in Normal.

Q. HAVE YOU PREPARED AN EXHIBIT THAT DESCRIBES YOUR QUALIFICATIONS?

A. Yes. My qualifications and previous experiences are shown on the attached Exhibit RMM-1.

Q. ON WHOSE BEHALF ARE YOU TESTIFYING?

A. I am testifying on behalf of the Public Staff of the North Carolina Utilities Commission ("Public Staff").

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to address certain depreciation-related issues presented in the testimony and filings of Public Service Company of North Carolina, Inc., d/b/a Dominion Energy North Carolina ("PSNC" or "Company") in this proceeding.

II. <u>Summary</u>

Q. CAN YOU SUMMARIZE YOUR RECOMMENDATIONS?

A. As discussed, and supported in this testimony, a reasonable adjustment to the depreciation parameters proposed in the PSNC

2020 Depreciation Study is the use of a -20% estimated future net salvage percent for Account 476.00, Distribution Mains, instead of -40% recommended by PSNC.

My recommended changes to PSNC's proposed depreciation parameters are based on my review of the 2020 Depreciation Study filed as Spanos Direct Exhibit 2 in this proceeding, my review of Witness Spanos's testimony regarding depreciation related issues filed in this proceeding, my review of the supporting information and workpapers provided in response to discovery, my review of previous Commission orders addressing PSNC's depreciation rates in North Carolina, and my previous experience in depreciation rate proceedings. I also reviewed Witness Spaulding's testimony regarding the impact of PSNC's proposed depreciation rates,[1] and Witness Harris's testimony regarding PSNC's recent projects.[2]

Q. DID YOU PARTICIPATE IN A FIELD VISIT OF PSNC'S FACILITIES IN NORTH CAROLINA?

A. Yes. On July 13-14, 2021, I participated in a field visit to several different PSNC facilities or project locations.[3] At each location,

[1] Direct Testimony of James A. Spaulding page 4, lines 3-14.
[2] Direct Testimony of D. Russel Harris page 5, line 16 through page 9, line 22.
[3] I visited the Stem Compressor Station, a regulator station, a city gate station, a take-off station, and two sites where active retirement projects were underway.

Company personnel and/or outside contractors discussed the facilities and ongoing projects with me.

Q. PLEASE COMPARE THE PUBLIC STAFF'S PROPOSED DEPRECIATION RATES WITH PSNC PROPOSED DEPRECIATION RATES.

A. PSNC's 2020 Depreciation Study results in a $3.8 million decrease in depreciation expense based on December 31, 2020 investments.

The annualized accrual based on the PSNC December 31, 2020 investments using the Public Staff's proposed depreciation rates compared to PSNC's proposed depreciation rates from the 2020 Depreciation Study, Spanos Direct Exhibit 2, are summarized in Table 1 below:

Table 1: Comparison of Annual Depreciation Accrual Amount Using Projected December 31, 2020 Investments

			PSNC Proposed		Public Staff Proposed		
Function	**12/31/20 Plant in Service**	**Current Approved Accrual Amount**	**Accrual Amount**	**Difference from Current**	**Accrual Amount**	**Difference from Current**	**Difference from Company Proposed**
Other Storage Plant	28,441,559	539,516	931,003	391,487	931,003	391,487	0
Transmission	830,623,953	18,591,750	17,682,820	(908,930)	17,682,820	(908,930)	0
Distribution	1,813,095,816	48,245,290	51,416,319	3,171,029	47,374,413	(870,877)	(4,041,906)
General	86,374,671	10,998,459	5,147,568	(5,850,891)	5,147,568	(5,850,891)	0
General Plant Amortization of Reserve	0	0	(603,278)	(603,278)	(603,278)	(603,278)	0
Total	**2,758,535,999**	**78,375,016**	**74,574,432**	**(3,800,584)**	**70,532,526**	**(7,842,490)**	**(4,041,906)**

The Public Staff's proposed remaining life depreciation rates compared to PSNC's proposed depreciation rates from the 2020 Depreciation Study, Spanos Direct Exhibit 2, are summarized in Table 2 below:

Table 2: Comparison of Proposed Annual Depreciation Rate

			PSNC Proposed		Public Staff Proposed		
Function	**12/31/20 Plant in Service**	**Current Approved Accrual Amount**	**Accrual Amount**	**Difference from Current**	**Accrual Amount**	Difference from Current	Difference from Company Proposed
Other Storage Plant	28,441,559	1.90%	3.27%	1.38%	3.27%	1.38%	0.00%
Transmission	830,623,953	2.24%	2.13%	-0.11%	2.13%	-0.11%	0.00%
Distribution	1,813,095,816	2.66%	2.84%	0.17%	2.61%	-0.05%	-0.22%
General	86,374,671	12.73%	5.96%	-6.77%	5.96%	-6.77%	0.00%
General Plant Amortization of Reserve	0						
Total	**2,758,535,999**	**2.84%**	**2.70%**	**-0.14%**	**2.56%**	**-0.28%**	**-0.15%**

Exhibit RMM-2 supports Tables 1 and 2 above.

Q. PLEASE DESCRIBE YOUR EXHIBIT RMM-2.

A. Exhibit RMM-2 contains the calculations of the Public Staff's remaining life proposed depreciation rates for PSNC Natural Gas Plant in North Carolina.

III. Definition of Depreciation

Q. COULD YOU PLEASE PROVIDE THE DEFINITION OF DEPRECIATION?

A. Yes. The Federal Energy Regulatory Commission ("FERC") definitions contained in the FERC Uniform System of Accounts (18 CFR 201 ("FERC USOA") state:

> 12.B. *Depreciation,* as applied to depreciable gas plant, means the loss in service value not restored by current maintenance, incurred in connection with the consumption or prospective retirement of gas plant in the course of service from causes which are known to be in current operation and against which the utility is not protected by insurance. Among the causes to be given consideration are wear and tear, decay, action of the elements, inadequacy, obsolescence, changes in the art, changes in demand and requirements of public authorities, and, in the case of natural gas companies, the exhaustion of natural resources.[4]

The FERC USOA definition of "depreciation" specifically states depreciation is a "loss in service value." FERC defines service value as "the difference between original cost and net salvage value of gas plant."[5]

Since this is a utility regulation proceeding, I rely on the FERC USOA definition of "depreciation" which focuses on the "loss of service value." Determining reasonable depreciation rates is necessary for

[4] FERC Uniform System of Accounts Prescribed for Natural Gas Companies Subject to the Provisions of the Natural Gas Act. (18 CFR 201).
[5] FERC USOA (18 CFR 201) Definition 37.

establishing the loss in service value of utility cost-based plant-in-service and incorporating it into ratemaking revenue requirement to allow for recovery of that cost.

A. <u>Overview of Depreciation Expense Impact on Revenue Requirement</u>

Q. PLEASE PROVIDE AN OVERVIEW OF THE IMPACT OF DEPRECIATION RATES ON THE REVENUE REQUIREMENT.

A. The depreciation rates approved by the Commission are multiplied by the test year investments to produce a calculated annual depreciation expense. The calculated depreciation expense is included in the revenue requirement that is to be recovered from ratepayers.

As pointed out by the National Association of Regulatory Utility Commissioners' ("NARUC") text *Public Utility Depreciation Practices*:

> It is essential to remember that depreciation is intended only for the purpose of recording the periodic allocation of cost in a manner properly related to the useful life of the plant. It is not intended, for example, to achieve a desired financial objective or to fund modernization programs.[6]

[6] Page 23, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

Q. WHAT IMPACT DO THE DEPRECIATION RATES SET IN THIS PROCEEDING HAVE ON FUTURE PROCEEDINGS?

A. The depreciation rates, or any other adjustment to the accumulated depreciation reserve, decided in this proceeding will impact the level of the accumulated depreciation reserve in a future rate case.

The depreciation expense amounts, based on the approved depreciation rates, are added to the accumulated depreciation reserve, while the accumulated depreciation reserve is decreased at the time of a retirement for the book cost of the plant retired and the cost of removal, less any salvage value.[7]

Adjustments to the accumulated depreciation reserve amount impact the allowed return on net rate base in a future rate case.

In a rate case, the calculated net rate base is multiplied by a rate of return (ROR) to calculate the shareholders' and other investors' "return on" their investment. The calculation of the allowed return on rate based included in customer rates expressed in a simplified way:[8]

allowed return = (investment – reserve) * ROR

[7] 18 CFR 201, Account 108.

[8] Other items such as cash working capital, materials and supplies, deferred income taxes, regulatory liabilities, regulatory assets, etc. are included in the net rate base calculation.

The accumulated depreciation reserve is the significant amount in the "reserve" part of the formula shown above.

B. <u>Calculation of Depreciation Rates</u>

Q. PLEASE PROVIDE A BRIEF DISCUSSION ABOUT THE REMAINING LIFE TECHNIQUES FOR CALCULATING DEPRECIATION RATES.

A. In the calculation of depreciation rates, the remaining life technique formula is:

$$\text{Depreciation Rate} = \frac{(100\% - \text{Book Reserve \%} - \text{Future Net Salvage \%})}{\text{Average Remaining Life}}$$

In the formula above, the book reserve percent is the actual accumulated depreciation reserve on the Company's books divided by the actual plant-in-service investment on the Company's books at the time of the Depreciation Study.

The Depreciation Study estimates the projected average service life of the assets, the retirement pattern of those assets, and the cost of removing or retiring those assets less any expected salvage from the sale, scrap, insurance, reimbursements, etc. of those assets. These estimates are referred to as depreciation parameters.

The projected average service life and retirement pattern (survivor curve) are the two parameters from the Depreciation Study that calculate the average remaining life.

The estimated future net salvage parameter from the Depreciation Study estimates the future cost of removing or retiring less any estimated future salvage.

Q. WHAT ARE SOME CONSIDERATIONS USED WHEN ESTIMATING THE DEPRECIATION PARAMETERS USED IN THE DEPRECIATION RATE FORMULA?

A. When estimating a depreciation parameter for an account, an initial step is to analyze that utility's actual historic life and net salvage experience data for that account. In addition to considering the lives and net salvage indicated by the utility's experience data, the expectations of the management, any changes to the current industry practices, and informed judgement are part of the estimation process.

Informed judgement as explained in NARUC's *Public Utility Depreciation Practices* states:

> *Informed judgment* is a term used to define the subjective portion of the depreciation study process. It is based on a combination of general experience, knowledge of the properties and a physical inspection, information gathered throughout the industry, and

> other factors which assist the analyst in making a knowledgeable estimate.
>
> The use of informed judgment can be a major factor in forecasting. A logical process of examining and prioritizing the usefulness of information must be employed, since there are many sources of data that must be considered and weighed by importance.[9]

IV. <u>Mass Property Future Net Salvage</u>

Q. PLEASE EXPLAIN WHAT IS MEANT BY NET SALVAGE.

A. NARUC's *Public Utility Depreciation Practices* defines net salvage as "the gross salvage for the property retired less its cost of removal."[10] Gross salvage is defined as "the amount recorded for the property retired due to the sale, reimbursement, or reuse of the property."[11] Cost of removal is defined as "the costs incurred in connection with the retirement from service and the disposition of depreciable plant. Cost of removal may be incurred for plant that is retired in place."[12]

NARUC also explains that careful consideration should be given to the net salvage estimate stating:

> Cost of retirement, however, must be given careful thought and attention, since for certain types of plant,

[9] Page 128, *Public Utility Depreciation Practices* published by the National Association of Regulatory Utility Commissioners (NARUC), 1996.
[10] Page 322, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.
[11] Page 320, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.
[12] Page 317, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

> it can be the most critical component of the depreciation rate.[13]

NARUC's *Public Utility Depreciation Practices* later points out that:

> Determining a reasonably accurate estimate of the average or future net salvage is not an easy task; estimates can be the subject of considerable discussion and controversy between regulators and utility personnel.[14]

Q. WHAT IMPACT DOES THE ESTIMATED FUTURE NET SALVAGE PERCENT HAVE ON DEPRECIATION RATES?

A. Positive net salvage results in a lower depreciation rate, all other things being equal. Negative net salvage results in a higher depreciation rate, all other things being equal.

As stated in NARUC's *Public Utility Depreciation Practices*:

> Positive net salvage occurs when gross salvage exceeds cost of retirement, and negative net salvage occurs when cost of retirement exceeds gross salvage.[15]

The estimated future net salvage is part of the annual depreciation accrual, which is credited to the depreciation reserve to cover the estimated future net salvage costs the company may incur in the future associated with plant asset retirements.

[13] Page 19, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.
[14] Page 157, *Public Utility Depreciation Practices* published by the National Association of Regulatory Utility Commissioners (NARUC), 1996.
[15] Page 18, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

Q. DID THE 2020 DEPRECIATION STUDY PROVIDE HISTORICAL NET SALVAGE DATA?

A. Yes. The PSNC depreciation study included the historic data of the actual incurred and recorded net salvage and related retirements. Regarding historic net salvage, PSNC's depreciation study states:

> The estimates of net salvage by account were based in part on historical data compiled for the years 1987 through 2020. Cost of removal and gross salvage were expressed as percents of the original cost of plant retired, both on annual and three-year moving average bases. The most recent five-year average also was calculated for consideration. The net salvage estimates by account are expressed as a percent of the original cost of plant retired.[16]

Q. WHAT IS A CONCERN REGARDING THE HISTORIC NET SALVAGE RATIOS CALCULATED IN THE DEPRECIATION STUDY?

A. As pointed out in Wolf and Fitch's *Depreciation Systems*:

> Salvage ratios are a function of inflation.[17]

Additionally, Wolf and Fitch's *Depreciation Systems*, points out that a historic net salvage ratio that includes inflated dollars in the numerator and historic dollars in the denominator is a ratio using different units, stating:

[16] Spanos Direct Exhibit 2 at 40.
[17] Page 267, Wolf, Frank K. and W. Chester Fitch, *Depreciation Systems* Iowa State University Press, 1994.

> One inherent characteristic of the salvage ratio is that the numerator and denominator are measured in different units; the numerator is measured in dollars at the time of retirement, while the denominator is measured in dollars at the time of installation. Inflation is an economic fact of life and although both numerator and denominator are measured in dollars, the timing of the cash flows reflects different price levels.[18]

The calculation of the historic net salvage ratio includes the impact of historic inflation rates, since the net salvage amount in the numerator is in current dollars and the cost of the plant (which may have been installed decades before) in the denominator is in historic dollars. In other words, due to inflation the amounts in numerator and denominator of the net salvage ratio are at different price levels.

Q. IS THE FACT THAT HISTORIC INFLATION IS INCLUDED IN THE NET SALVAGE RATIO RECOGNIZED IN ANOTHER AUTHORITATIVE DEPRECIATION TEXT?

A. Yes. NARUC's *Public Utility Depreciation Practices*, regarding inflation states:

> The sensitivity of salvage and cost of retirement to the age of the property retired is also troublesome. Due to inflation and other factors, there is a tendency for costs of retirement, typically labor, to increase more rapidly than material prices.[19]

[18] Page 53, Wolf, Frank K. and W. Chester Fitch, *Depreciation Systems* Iowa State University Press, 1994.
[19] Page 19, *Public Utility Depreciation Practices*, published by National Association of Regulatory Commissioners (NARUC), 1996.

Q. WHY SHOULD THE IMPACT INFLATION HAS ON THE HISTORIC NET SALVAGE RATIOS BE CONSIDERED WHEN ESTIMATING THE FUTURE NET SALVAGE AMOUNTS TO BE COLLECTED FROM TODAY'S RATEPAYERS?

A. The estimated future net salvage accruals included in the revenue requirement in this proceeding are to be collected from the ratepayers in today's more valuable current dollars. Therefore, I not only reviewed the historic net salvage data as presented in the depreciation study and the underlying data provided in response to discovery, I also evaluated the impact of collecting the more valuable current dollars from the ratepayers to pay for estimated future costs.

Q, PLEASE EXPLAIN WHAT YOU MEAN BY MORE VALUABLE CURRENT DOLLARS.

A. Due to inflation, today's dollar has more purchasing power than a future dollar.

Q. HAVE YOU REVIEWED THE RECOVERY OF ESTIMATED FUTURE NET SALVAGE COSTS INCLUDED IN PSNC'S PROPOSED DEPRECIATION ACCRUAL AND THE ACTUAL NET SALVAGE COSTS PSNC HAS INCURRED IN TODAY'S DOLLARS IN THE LAST FEW YEARS?

A. Yes. A depreciation recommendation requires judgement. Relevant information in addition to what has been presented in PSNC's

Depreciation Study can properly be considered. The interests of the Company should be considered, but the interests of the ratepayers should also be considered.

As a reasonableness check on the estimated future net salvage accrual amount to be included in the revenue requirement, which is collected from the ratepayer in today's dollars, I have compared the estimated future net salvage costs included in PSNC's proposed depreciation accrual to the actual net salvage costs incurred by PSNC on average over the recent five-year period. This comparison is shown in Exhibit RMM-3.

Q. COULD THE AMOUNT INCLUDED FOR FUTURE NET SALVAGE IN THE ANNUAL DEPRECIATION ACCRUAL SHOWN IN EXHIBIT RMM-3 CHANGE IN THE FUTURE?

A. Yes. The annual amount for net salvage is calculated on the investment as of December 31, 2020. In the future, as the plant-in-service investment in the account increases, the amount for estimate future net salvage would increase in proportion to the increase in investment.

Q. ARE YOUR PROPOSED ESTIMATED FUTURE NET SALVAGE PERCENTS BASED ONLY ON THE COMPARISON SHOWN IN EXHIBIT RMM-3?

A. No. This is evidenced by the fact that my proposed estimated future net salvage accrual amounts are not equal to the average annual historical amount as shown in Exhibit RMM-3.

As discussed above, estimating the depreciation parameters includes informed judgement. My analysis included the review of the historic net salvage data provided in the depreciation study and the relevant information provided in response to discovery. My proposed estimated future net salvage accrual amounts are in current dollars that consider PSNC's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and my previous experience.

Exhibit RMM-3 is a reasonableness check on the estimated future net salvage accrual amount to be included in the revenue requirement.

Q. WHY IS THE ESTIMATED FUTURE NET SALVAGE PARAMETER SHOWN AS A PERCENT?

A. The future net salvage parameter is an estimate of the future cost that may be incurred related to future plant retirements. Since the depreciation study produces a depreciation rate, the estimated future net salvage is included in the depreciation rate formula as a percent of the investment as of December 31, 2020. The depreciation rates resulting from the depreciation study are then applied to the investment amounts as of the date of the test year in the rate proceeding.

Q. BASED ON YOUR REVIEW DO YOU RECOMMEND A DIFFERENT ESTIMATED FUTURE NET SALVAGE PERCENT FOR ANY MASS PROPERTY ACCOUNTS?

A. Yes. For Account 476.00, Distribution Mains I recommend an estimated future net salvage percent of -20% compared to PSNC's proposed -40%.

Q. PLEASE EXPLAIN HOW YOUR RECOMMENDED ESTIMATED FUTURE NET SALVAGE OF -20% FOR ACCOUNT 476.00, DISTRIBUTION MAINS IS MORE REASONABLE THAN PSNC'S PROPOSAL.

A. As shown in Exhibit RMM-3, for Account 476.00, Distribution Mains, over the recent five-year period, PSNC actually incurred $494,127 on average per year.[20]

PSNC's proposed estimated future net salvage of -40% collects $6,096,807 in annual accrual from ratepayers, which is 12.3 times the average annual amount PSNC has actually incurred for net salvage.

In my judgement, PSNC collecting annually from ratepayers for net salvage over 12 times as much as the annual costs PSNC incurs for net salvage is excessive and should be adjusted.

I recommend an estimated future net salvage of -20% for Account 476.00, Distribution Mains. My recommendation results in an annual accrual of $2,876,073, which is 5.8 times the average annual amount PSNC has actually incurred for net salvage.[21]

[20] Spanos Direct Exhibit 2 at 194.

[21] I am not recommending or implying a change from the "accrual" basis to the "cash" basis for the recovery of future net salvage costs. In other words, I am not recommending or implying that the depreciation accrual no longer be credited to the Accumulated Provision for Depreciation or that the net salvage costs be "expensed."

My proposed net salvage accrual is a good balance between the depreciation expense charged to current customers and the building of the book reserve to cover any PSNC future net salvage costs associated with the retirement of an asset.

Q. WHAT SUPPORT DID PSNC PROVIDE THAT SUPPORTS ITS PROPOSED ESTIMATED FUTURE NET SALVAGE OF -40% FOR ACCOUNT 476.00, DISTRIBUTION MAINS BUT AN ESTIMATED FUTURE NET SALVAGE OF -15% FOR ACCOUNT 467.00, TRANSMISSION MAINS.

A. In response to discovery, the Company provided two differences between the retirement of Transmission Mains and Distribution Mains.

The first reason given by the Company is related to the average length of the main being retired. The Company's response states:

> Most transmission main retirement projects are fairly long lengths of pipe being retired and, therefore, only two holes are needed to properly retire the large asset value. For distribution mains, there are much smaller lengths of pipe being retired for each project and in many cases a project may only be a valve being retired.[22]

[22] PSNC Response to Public Staff Data Request No. 55-4, attached as Exhibit RMM-4.

The length of the pipe being retired does not change the cost incurred to retire that section of pipe, since both Transmission Mains and Distribution Mains are "typically retired in place."[23]

The second reason given by the Company is due to Distribution Mains more often being placed in streets, which can result in an increase in the restoration cost. The Company's response states in pertinent part:

> Additionally, more distribution mains are laid in the streets, which requires more costly site restoration.[24]

The PSNC average historic net salvage actually incurred, shown on Exhibit RMM-3 and used in the comparison, does include the "more costly site restoration" for Distribution Mains, since those cost differences would be reflected in the historic net salvage data.

In my judgement the "more costly site restoration" does not support collecting an annual accrual from ratepayers that is 12.3 times the average annual amount PSNC has actually incurred for Distribution Mains net salvage.

By comparison, as shown on Exhibit RMM-3, PSNC's proposed estimated future net salvage of -15% for Account 467.00,

[23] PSNC Response to Public Staff Data Request No. 23-14, attached as Exhibit RMM-5 and PSNC Response to Public Staff Data Request No. 23-15, attached as Exhibit RMM-6.

[24] PSNC Response to Public Staff Data Request No. 55-4, attached as Exhibit RMM-4.

Transmission Mains results in an annual accrual for estimated future net salvage that is 6.1 times the average annual amount PSNC has actually incurred for Transmission Mains net salvage.

My recommended estimated future net salvage of -20% for Account 476.00, Distribution Mains is 5.8 times the average annual amount PSNC has actually incurred for net salvage, which is similar to the 6.1 times for Account 467.00, Transmission Mains and more reasonable than PSNC's proposed 12.3 times for Account 476.00, Distribution Mains.

Q. DOES YOUR PROPOSED -20% ESTIMATED FUTURE NET SALVAGE PERCENT RESULT IN AN UNDER-RECOVERY OF THE ESTIMATED FUTURE COSTS?

A. No. As stated above, my recommendation results in an annual accrual that is 5.8 times the average annual amount PSNC has actually incurred for net salvage; therefore, my recommendation provides recovery of the estimated cost of removal expected to be incurred in the near future and builds the reserve for estimated future cost of removal associated with future retirements.

V. Conclusion

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. For the reasons stated above, I recommend that the Public Staff's proposed depreciation rates shown on Exhibit RMM-2 be approved for PSNC in North Carolina.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

MS. HOLT: I move that the prefiled testimony of Neha Patel, consisting of 28 pages, be copied into the record as if given orally from the stand and that her three (3) exhibits be identified as marked when filed and entered into evidence.

COMMISSIONER BROWN-BLAND: All right. That motion also is allowed.

(Patel Exhibits I through III were marked for identification and received into evidence.)

(Whereupon, the prefiled direct testimony of Neha Patel was copied into the record as if given from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632

<table>
<tr><td>DOCKET NO. G-5, SUB 632

In the Matter of
Application of Public Service Company of North Carolina, Inc., for an Adjustment of Natural Gas Rates and Charges in North Carolina

DOCKET NO. G-5, SUB 634

In the Matter of
Application for Approval to Modify Existing Conservation Programs and Implement New Conservation Programs</td><td>)
)
)
)
)
)
)
)
)
)
)
)
)
)
)
)
)</td><td>TESTIMONY OF
NEHA PATEL
PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION</td></tr>
</table>

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

TESTIMONY OF NEHA PATEL

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 23, 2021

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

A. My name is Neha Patel. My business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am the Manager of the Natural Gas Section of the Energy Division of the Public Staff – North Carolina Utilities Commission (Public Staff).

Q. BRIEFLY STATE YOUR QUALIFICATIONS AND DUTIES.

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

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to present the results of my investigation into the application of Public Service Company of North Carolina, Inc. (PSNC or the Company), for a general rate increase in this proceeding.

Q. WHAT WERE YOUR AREAS OF INVESTIGATIVE RESPONSIBILITY IN THIS CASE?

A. My areas of investigation in this case were: (1) determining the appropriate sales and transportation volumes and customer levels, (2) evaluating the proposed weather normalization adjustment for the test period, (3) calculating the customer growth factors, (4) calculating the appropriate end-of-period level of revenues, (5) fixed gas costs and lost and unaccounted for (LUAF) adjustments, (6) calculating the appropriate level of other operating revenues, (7) calculating the updated computational factors used in the Customer Utilization Tracker (CUT) mechanism, (8) general capital additions to plant, (9) reviewing proposed revisions to the Company's tariff, which consists of its various rate schedules and service regulations, (10) evaluating PSNC's request to continue its Commission-approved Integrity Management Tracker (IMT) mechanism, (11) evaluating PSNC's programs to defer operating and maintenance (O&M) expenditures under both its Transmission Integrity Management Program (TIMP) and Distribution Integrity Management Program (DIMP), (12) Evaluating PSNC's proposed GREENTHERM™ program, (13) evaluating the Company's Research and Development proposal, and (14) evaluating PSNC's service quality.

WEATHER NORMALIZATION AND CUSTOMER GROWTH

Q. WHAT IS THE PURPOSE OF ADJUSTING FOR WEATHER NORMALIZATION AND CUSTOMER GROWTH?

A. Weather normalization attempts to analyze and adjust for the impact of actual weather conditions over a specified time period (generally, a test year) on energy consumption relative to expected "normal" weather conditions (as measured over some longer historical period of time).

The customer growth adjustment adjusts test period revenues by an amount that represents the growth in sales due to the change in the number of customers.

The Public Staff runs its own weather normalization and customer growth models and compares the results to those included in the Company's general rate case filing.

The Public Staff's linear regression model that computes the baseload (minimum usage level) and a Heat-Sensitive Factor (HSF) is similar to that of the Company. Using this linear regression model, the Public Staff obtained results similar to that of the Company for comparable customer class usage for the heat sensitive customers.

Q. PLEASE EXPLAIN HEATING DEGREE DAYS (HDDS) AND HOW THEY ARE UTILIZED IN YOUR LINEAR REGRESSION.

A. HDD is a measurement that quantifies the demand for energy needed for space heating. HDDs are calculated by subtracting the average daily temperature from a standard temperature of 65 degrees Fahrenheit.[1] For example, a low of 20 degrees and a high of 40 degrees would yield an average of 30 degrees and an HDD of 35 degrees (65 - ((20 + 40)/2)). The normal HDDs are determined based on a 30-year historical average.

To determine customer usage under normal weather conditions, the Public Staff completed a linear regression to compare the actual customer usage to the actual HDDs to derive the baseload and the heat sensitive factors for the test year period. My completed analysis results in similar regression results to that of the Company.

Q. PLEASE DISCUSS THE PUBLIC STAFF'S GROWTH ADJUSTMENTS TO CUSTOMER BILLS AND CONSUMPTION.

A. The Public Staff compares actual changes in the number of monthly customer bills between the test year and the year immediately prior. This comparison produces the average growth rate that the Public

[1] The use of 65 degrees Fahrenheit is based on an assumption that heating is not needed when the outside temperature is 65 degrees or more.

Staff applies to each rate class. Due the COVID-19 pandemic and the Commission's moratorium on disconnections for non-payment in effect during the test year, the Company did not disconnect service for non-payment of bills for a majority of the test period. As a result, the test period reflects a higher number of customer bills as compared to prior years. However, in consideration of the anticipated expiration of the disconnection moratorium, and with new customers being added to the system, the Public Staff applied a growth rate to the Residential and the High Efficiency Residential Service customer classes using the same methodology as the Company in applying the actual growth factors from customers billed from 2018 through 2019 (when there was no disconnection moratorium in place) to the above customer classes, as well as, making adjustments to certain large-volume customers with known and available information.

Q. WHAT TOTAL SALES AND TRANSPORTATION CUSTOMER BILLS AND VOLUME DID YOU USE TO CALCULATE END-OF-PERIOD REVENUES?

A. Based on my analysis, I determined that the appropriate level of end-of-period sales and transportation customer bills is 7,388,094 and total sales and transportation volume is 1,318,864,912 therms (ths), as shown in Patel Exhibit I.

Q. PLEASE PROVIDE AN EXPLANATION FOR YOUR ADJUSTMENTS SHOWN IN PATEL EXHIBIT I.

A. Patel Exhibit I, Columns (4) and (5) show the per books number of bills and the per books sales and transportation volumes segmented by rate schedule for the test year ended December 31, 2020. Weather normalized volumes, shown in Column (6), adjusts the volumes for the heat-sensitive customers (Rate Schedules 101, 102, 125, 127 and 140). The Public Staff and the Company agree on the weather normalization calculation methodology, although my adjustments differ slightly from that of the Company's pro forma bills and usage (ths) due to rounding.

END-OF-PERIOD REVENUE CALCULATIONS

Q. WHAT RATES DID YOU USE TO CALCULATE THE END-OF-PERIOD PRO FORMA REVENUE LEVEL?

A. To calculate the end-of-period pro forma revenue level, I used the rates approved by the Commission in Docket No. G-5, Sub 633[2] and the Company's updated IMT rates as approved by the Commission in Docket No. G-5, Sub 636[3]. These rates exclude any temporary

[2] Application for Bi-Annual Adjustment of Rates Under Rider C to its Tariff, Order Approving Rate Adjustments Effective April 1, 2020 (March 30, 2021).

[3] Application of Public Service Company of North Carolina, Inc. for Bi-Annual Adjustment of Rates Under Rider E to its Tariff, Order Approving Rate Adjustments Effective September 1, 2020 (August 31, 2020).

increments or decrements (temporaries) that were included in rates at that point in time. This calculation produces what is known as "clean rates."

Q. WHY ARE TEMPORARIES REMOVED FROM RATES FOR RATE CASE ANALYSIS?

A. Temporaries are usually associated with deferred account activities and are not related to revenue generation for the Company. The margins associated with various rate schedules are typically not affected by temporaries, except when the temporaries are associated with fixed gas costs. Temporaries are removed when calculating end-of-period rates and proposed rates to achieve consistency and for ease of understanding. After the Commission determines the proper rates in this case, the new billing rates will be adjusted for the temporaries currently in effect.

Q. WHAT IS YOUR END-OF-PERIOD REVENUE CALCULATION FOR THE COMPANY?

A. The Company is proposing total end-of-period revenues of $574,112,825, which is comprised of sales and transportation of gas revenues of $573,392,181 and other operating revenues of $720,644. I have calculated end-of-period revenues as shown in Patel Exhibit II and I have used a three-year average to determine the appropriate level of other operating revenues.

Q. HOW DID YOU CALCULATE THIS END-OF-PERIOD LEVEL OF REVENUE FOR THE COMPANY?

A. The product of the number of customer bills and facilities charge for each rate schedule is the facility charge revenue. Likewise, the volume for each rate schedule was multiplied by the end-of-period rates to arrive at the total energy revenues. The sum of the revenues for the total facilities charge for a particular rate schedule, the energy revenue for that rate schedule, corresponding IMT revenues for that rate schedule and any CUT adjustments equals the total end-of-period revenue level as shown on Patel Exhibit II.

GAS COSTS

Q. DO YOU AGREE WITH THE COMPANY'S ADJUSTMENT TO FIXED GAS COSTS?

A. No. While I do agree with the Company's end of period fixed gas costs, I have also reflected an on-going level of secondary market credits in the determination of total fixed gas costs in order to allow the customers to receive the benefits of the secondary markets revenues earned each year through reduced rates. I have included a three-year average for the secondary market credits in my fixed gas cost calculations as shown in Patel Exhibit III.

CUT MECHANISM

Q. PLEASE EXPLAIN ANY ADJUSTMENTS REGARDING THE MDT MECHANISM.

A. In this proceeding, the Company filed CUT adjustments to the Residential, High Efficiency Residential Service, Small General Service, High Efficiency Small General Service, and Medium General Service rate schedules. I calculated the normalized usage for heat sensitive customers on a monthly basis and determined the "R" factors. This calculation results in an adjustment in an increase to the Residential, High Efficiency Residential, and Medium General Service total pro forma revenues and a decrease to the Small General and High Efficiency Small General Service pro forma revenues. My results are similar to that of the Company but the Public Staff's CUT revenue adjustments differ slightly due to rounding.

GENERAL CAPITAL ADDITIONS TO PLANT IN SERVICE

Q. WHAT WERE YOUR AREAS OF INVESTIGATIVE RESPONSIBILITY IN THIS CASE?

A. While I participated in and contributed to a number of areas of the Public Staff's investigation, I specifically reviewed or supervised the review of the following areas:

- Multiple transmission pipeline projects, notably the T-1 and T-30 transmission projects
- General capital spend
- Company vehicles
- Materials and supplies

CHANGES TO PSNC'S TARIFF

Q. WHAT CHANGES IS PSNC PROPOSING TO ITS NORTH CAROLINA TARIFF?

A. As mentioned by Company witness Hinson, many of the proposed changes are administrative in nature for the sole purpose of making the language more comprehensible.

- Following the 2019 SCANA merger with Dominion Energy Inc., the Company proposes to refer to itself as 'Company' throughout the tariff instead of 'PSNC' in an attempt to avoid any confusion.

- To eliminate any probable confusion between the Commission's Rules and Regulations and the Company's 'Rules and Regulations', it has elected to replace it with, 'Service Regulations.'

- The Company's Service Regulations will now render definitions for, 'Emergency Service', 'Unauthorized Gas', 'Service Regulations' and 'Tariff'. 'Standard Service' being an undefined term in the prior Service Regulations when defining 'Excess Facilities' has been removed and the proposed revision clarifies that the facilities are to provide service at a pressure higher than that as specified in the tariff using a farm tap.

- The Company is also proposing similar administrative changes to Appendix A (form for Transportation Pooling Agreement) and Appendix B (Gas Quality standards for Renewable Gas).

- Witness Hinson has proposed changes to update the Special Contract Credit amounts, margin percentages by rate class, allocation factors, and the annual billing determinants, etc., for the IMT mechanism in Rider E as is necessary with each new general rate case proceeding. Public Staff witness Perry refers to these items in her testimony.

IMT MECHANISM

Q. PLEASE PROVIDE A BRIEF OVERVIEW OF FEDERAL GAS PIPELINE SAFETY REQUIREMENTS.

A. As discussed by Company witness Randall[4], pipeline operators are required to perform integrity measures on their transmission and distribution pipelines by following the regulatory requirements imposed by the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration (PHMSA) under its TIMP and DIMP.

The TIMP and DIMP activities are cyclical, are based on timing and intervals of prior assessments, and vary from year to year.

Effective July 1, 2020, PHMSA required all pipeline operators to comply with the new Gas Transmission "Mega Rule,"[5] which provides an expansion of the Integrity Management (IM) requirements for gas transmission pipelines and aims to further increase the level of safety associated with gas transmission pipelines. A significant portion of this rule outlines documentation requiring operators to: (1) Verify pipeline material properties and attributes: Operators must have information on the material strength

[4] Direct Testimony of Company witness Randall at 4.

[5] PHMSA - Pipeline Safety: Safety of Gas Transmission Pipelines

properties for all transmission pipe; (2) Reconfirm Maximum Allowable Operating Pressure (MAOP): This applies to those transmission pipelines where pressure test records are not traceable, verifiable and complete (TVC); and (3) Expand IM requirements outside HCAs: Periodic assessments of pipelines in populated areas not designated as HCAs to Moderate Consequence Areas (MCAs).[6]

Q. PLEASE PROVIDE SOME BACKGROUND ON THE COMPANY'S IMT MECHANISM.

A. N.C. Gen. Stat. § 62-133.7A authorizes the Commission to approve a rate adjustment mechanism to enable a natural gas local distribution company (LDC) to recover its prudently incurred capital investments and associated costs of complying with federal gas pipeline safety requirements. The Commission approved an IMT mechanism in PSNC's 2016 general rate case[7] and it is contained in Rider E to PSNC's Service Regulations. The IMT mechanism excludes recovery of certain costs (Excluded Costs) and includes bi-annual rate adjustments. The Excluded Costs percentages are

[6] Moderate Consequence Areas (MCAs) are defined as areas within a potential impact circle containing either five or more buildings intended for human occupancy or any portion of the paved surface, including shoulders, of a designated interstate, freeway, or expressway, or principal arterial roadway with four or more lanes, as defined by the Federal Highway Administration (as compared to 20 buildings which define an HCA).

[7] G-5, Sub 565Application for a General Rate Increase, Order Approving Rate Adjustments Effective March 1, 2017 (February 28, 2017)

intended to reduce the level of non-pipeline safety costs charged to customers through the IMT mechanism These costs are still eligible for recovery in rate base if prudent, in PSNC's next general rate case.

On October 4, 2018, an Agreement and Stipulation of Settlement between Dominion Energy, Inc., SCANA Corporation, Transcontinental Gas Pipe Line Company, LLC ("Transco"), and the Public Staff was filed, which included stipulated Regulatory Conditions and a Code of Conduct ("Merger Settlement")[8]. The Merger Settlement included a rate moratorium for PSNC from filing an application for a general rate case before April 1, 2021. On November 19, 2018, the Commission issued its Order Approving Merger Subject to Regulatory Conditions and Code of Conduct ("Merger Order") in Docket Nos. E-22, Sub 551, and G-5, Sub 585[9]. On June 26, 2020, PSNC filed a petition with the Commission for an extension of its IMT mechanism in Rider E (without any modification) until the earlier of two years or the Company's next general rate case. The Commission granted PSNC's request for an extension to its IMT mechanism until November 1, 2022 or its next general rate case on August 10, 2020[10].

[8] Joint Application of Dominion Energy Inc. and SCANA Corporation

[9] Order Approving Merger Subject to Regulatory Conditions and Code of Conduct

[10] Order Approving Extension of Integrity Management Tracker

PSNC has included, as part of this proceeding, a proposal to continue operation of this mechanism.

Since the Sub 565 rate case, PSNC has applied for and received Commission approval to implement 10 bi-annual rate changes to recover the Integrity Management Revenue Requirement (IMRR) on plant investment through the IMT.

The Public Staff reviews and audits PSNC's monthly IMT reports filed with the Commission through data requests and follow-up conference calls with Company personnel regarding project scope, project need, actual project costs incurred, and the nature of IMT-associated costs. In addition, the Public Staff files an Annual IMT Report with the Commission on May fifteenth of each year in order to discuss any issues from the monthly audits, or the IMRR calculations, summarize the completed IMT projects, and provide the budgeted IMT projects for the next three years.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION REGARDING PSNC'S REQUEST TO CONTINUE THE IMT MECHANISM.

A. Based on the importance of pipeline safety in complying with federal safety guidelines and with any additional amendments to PHMSA regulations, PSNC is required to perform integrity measures on its transmission and distribution system to protect its customers, employees, contractors and the general public. I recommend the IMT mechanism remain in place.

DEFERRED TIMP-RELATED O&M COSTS

The Commission has approved deferred accounting treatment for the Company's TIMP O&M costs incurred due to the pipeline safety regulations promulgated by PHMSA. Since the last general rate case, the Company has enacted significant measures to conform to the regulations promulgated by PHMSA. Under PHMSA, pipeline operators are mandated to identify High Consequence Areas (HCAs), or covered segments, in order to identify threats to their pipelines; identify and analyze the risk to help prioritize assessments; remediate conditions found during integrity assessments; maintain records; and implement preventative and mitigative measures. Based on PHMSA guidelines, operators must perform pipeline reassessments which drives up the costs added to the rate base while allowing the Company to mitigate threats and risks identified on these pipelines and ensure safely on their transmission lines. I recommend that PSNC be allowed to continue its deferral mechanism under TIMP until the resolution of the Company's next general rate case proceeding.

In order to have more transparency with the audits, I further recommend that the Company work with the Public Staff to segregate TIMP costs by pipeline pigging segments or sub-projects for better tracking purposes and to continue providing program updates to the Commission, including the project scope/description, in the monthly filings, as well as providing the budgeted and actual costs incurred in an annual filing to provide the TIMP costs and invoices from the prior 12-month period. While my area of investigation focused on the necessity of this mechanism, Public Staff accounting witness Feasel discusses the audit of these costs in the rate case.

<u>DEFERRED DIMP-RELATED O&M COSTS</u>

Q. PLEASE DISCUSS YOUR REVIEW OF THE COMPANY'S DEFERRED DIMP-RELATED O&M COMPLIANCE COSTS.

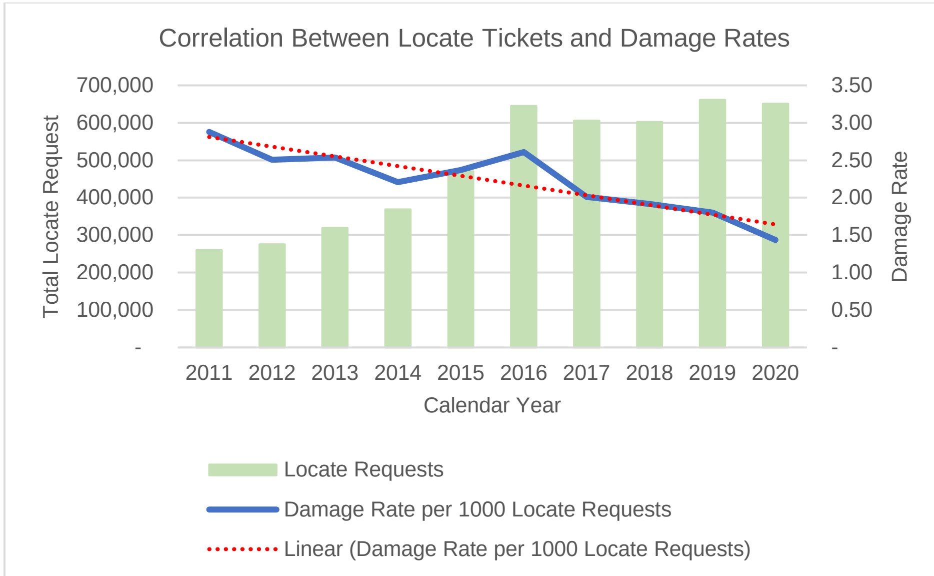
A. The Commission has approved deferred accounting treatment for PSNC's DIMP O&M costs associated with PHMSA regulatory compliance. Among other areas, the Company's DIMP primarily covers the following areas of pipeline safety:

1. Inspection/Practices: (a) Enhanced leak survey, (b) legacy cross bore, (c) Gold Shovel Standard certification[11], and (e) locatability investigations/repair untoneable assets;
2. Enhanced Cathodic Protection: (a) Anode replacement, Close internal surveys, AC mitigation;
3. Safety Communications/Public Awareness: Damage prevention, 811-verification; and
4. Records: mapping services in the GIS.

The Company noted that third party contractors are engaged to perform the work covered by these programs, however due to the COVID-19 pandemic; the Company has experienced a delay in the implementation of some of the DIMP programs.

As part of my investigation, I reviewed data request responses from the Company regarding the DIMP-related O&M project scope and associated costs. Under damage prevention program, I reviewed data from 2011 to 2020 from federal pipeline safety regulators related to the Company's annual damage rates and the relationship to the number of locate requests. Patel Figure 1 below shows the history of locate requests and the associated damage rates per 1000 locate tickets.

[11] Gold Shovel Standard



Patel Figure 1

From 2011 to 2014, the Company received approximately 300,000 locate requests in any given year, and the damage rate averaged 2.51 damage incidents annually. After 2014, the damage rate increased; reaching a high of about 2.75, before declining substantially over the last four years despite an increase in locate requests.

The Company implemented measures to reduce third party damages such as mailers to registered excavation companies within the Company's service territory and newspaper, billboard, US mail, signage and social media advertising. The Company has various public awareness programs in place to help reduce third party damage incidents. They are: (1) Risk Ranking "811" tickets, and Watch & Protect Program; (2) Untoneable Repair Program; and (3)

Geofencing. Such measures have had a positive impact on the damage ratio to its infrastructure; nevertheless, the Public Staff will continue to analyze this data to assess the impacts of the programs.

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S DEFERRED DIMP O&M EXPENSES?

A. The issue of pipeline safety, and specifically the testing of LDCs' systems, along with the implementation of safety programs, has come to the forefront in the past 10 to 15 years. The focus was initially on transmission systems and now includes distribution systems as well. The Company has incurred significant expenses to address pipeline safety and remain compliant with PHMSA regulations, which have been amended as recently as 2019 to expand obligations.[12]

The primary cost drivers affecting the Company's forecast include contracted labor to meet safety compliance and documentation per federal DIMP regulatory requirements. It is difficult to put a cost on pipeline safety and the prevention of property damage and personal injury or death that can occur from a natural gas incident.

[12] Direct Testimony of Company witness Randall at page 6.

I recommend that PSNC be allowed to continue its deferral mechanism until the resolution of the Company's next general rate case proceeding, and that the Company provide to the Commission annual program updates including project scope, and the budgeted and actual costs incurred in an annual filing to provide the DIMP costs and invoices from the prior 12-month period.. While my area of investigation of focused on the necessity of this mechanism, Public Staff accounting witness Feasel discusses the audit of these costs in the rate case.

GREENTHERM™ PROGRAM

Q. HAS THE PUBLIC STAFF REVIEWED THE COMPANY'S PROPOSAL TO OFFER A VOLUNTARY RENEWABLE ENERGY PROGRAM ALLOWING CUSTOMERS TO SUPPORT THE DEVELOPMENT OF RENEWABLE ENERGY BY PURCHASING "GREEN ATTRIBUTES" OF RENEWABLE NATURAL GAS?

A. Yes. The Company is proposing to offer a GreenTherm™ Program[13] modeled on a program offered by its affiliate Dominion Energy Utah. Customers would participate by paying a monthly surcharge to purchase a block of green attributes equal to five therms of renewable natural gas. PSNC plans to issue a Request for Proposals

[13] Testimony of Company witness Randall (GreenTherm™ program, pg. 17)

(RFP) if the Commission approves the program. Based on the results of the RFP, the Company will determine the appropriate rate for a five-therm block.

Q. WHAT IS THE PUBLIC STAFF'S RECOMMENDATION REGARDING THE PROPOSED GREENTHERM™ PROGRAM?

A. The Public Staff supports PSNC's development of a voluntary program allowing customers to support the development of renewable gas and recommends that the Commission order PSNC to proceed with the development of the program. However, the Public Staff does not believe that the program should receive final approval until the Company has received the results of the RFP, determined the cost of a block of five therms, and determined its sources for renewable gas. The Public Staff also believes the PSNC should ensure that its green attributes meet certain standards and are certified, such as the standards and certification offered by Green-e®.[14] The Company has also informed the Public Staff that it may also offer carbon offsets through this program or a separate program. Once the Company has fully developed the program, the Company should update its proposal and file it with the Commission.

[14] https://www.green-e.org/renewable-fuels

RESEARCH AND DEVELOPMENT

Q. WHAT IS YOUR RECOMMENDATION REGARDING THE COMPANY'S PROPOSED ADJUSTMENTS ON ITS R&D EFFORTS?

A. PSNC has proposed in this rate case a project that focuses on studying the effects of blending hydrogen with natural gas in determining its safety and viability in the testimony of Company witness Randall, and witness Spaulding has the proposed adjustment of $285,000 to fund this initiative. An affiliated gas utility in Utah has a similar pilot project underway, which is studying the feasibility of hydrogen blending, its availability, storage and pricing. Not having retained any contractors for this study, the program costs as reflected in witness Spaulding's exhibits are based on an estimate from the Utah pilot project. Company responses to Public Staff data requests have not provided any costs specific to this program for North Carolina. The Public Staff should be given the opportunity to examine such new projects and make recommendations to the Commission before its implementation. Therefore, the Public Staff does not agree the Company's proposal of approving this project and allowing the R&D costs to be recovered.

PSNC'S QUALITY OF SERVICE

Q. WHAT FACTORS DID YOU CONSIDER IN YOUR EVALUATION OF PSNC'S OVERALL QUALITY OF SERVICE PROVIDED TO ITS CUSTOMERS?

A. I reviewed the following information in my evaluation of PSNC's quality of service:

- Informal complaints and inquiries from PSNC customers received by the Public Staff's Consumer Services Division;
- Customer Call Center Monthly Reports filed in Docket No. G-100, Sub 96PSNC;
- Data on pipeline incident and damage rates (see Patel Figure 3); and
- Company initiatives that impact the level of service being provided to customers.

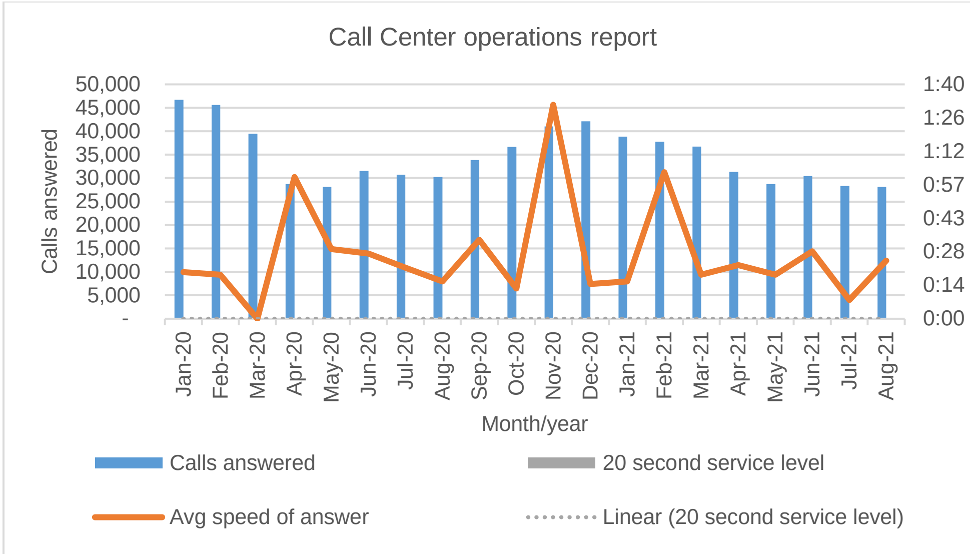
Q. WHAT TYPES OF CUSTOMER COMPLAINTS AND INQUIRIES HAVE BEEN RECEIVED BY THE PUBLIC STAFF'S CONSUMER SERVICES DIVISION?

A. For the period January 2016 through April 2021, the Public Staff's Consumer Services Division received approximately 499 contacts from PSNC customers. Of those contacts, 78% related to billing and payment issues including the establishment or modification of payment arrangements and questions about current customer bills. The remaining 22% involved rate, service, and meter-related issues.

Q. PLEASE DESCRIBE THE OTHER DATA USED IN YOUR REVIEW.

A. The other data used in my review were obtained through PSNC's Commission-required filings and responses to Public Staff data requests. I was able to analyze the Company's: (1) call center response times to customer inquiries, (2) response times to emergency response calls/events, and (3) the correlation between damage rates and the number of locate request tickets issued to the Company.

With regard to the Customer Call Center information filed in Docket No. G-100, Sub 96PSNC, from January 2020 to August 2021, the Company and its third party call centers answered 694,788 calls with an answer rate of 98%. In addition to the number of calls answered by customer service representatives, the Company's Interactive Voice Response (IVR) answering system handled an additional 472,484 calls during this same timeframe. Per G-100, Sub 96PSNC Reports, on average, the Company's performance on the "20 second service level" to customer calls has an overall high performance of answering calls within 20 seconds as can be seen from Patel Figure 2 below, while also focusing on improving call response time during the winter months.



Patel Figure 2

Q. HOW WOULD YOU RATE PSNC'S SERVICE QUALITY?

A. Based on my investigation, I believe the overall quality of service provided by PSNC to its North Carolina customers is adequate at this time.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

APPENDIX A

QUALIFICATIONS AND EXPERIENCE

NEHA PATEL

I graduated from the University Of Mumbai in 1995 with a Bachelor of Science degree in Electronic Engineering. I began working as a Utilities Engineer with the Natural Gas Division of the Public Staff in the spring of 2014. In 2020, I became Manager of the Natural Gas Section of the Energy Division.

I have worked on purchased gas cost adjustment procedures, tariff filings, customer utilization trackers, special contract review and analysis, weather normalization adjustments, customer complaint resolutions, integrity management riders, franchise exchange filings, compressed natural gas special contracts, peak day demand and capacity calculations, fuel and electric usage trackers, gas resellers, annual review of gas costs proceedings, renewable natural gas filings, cost of service studies, general rate case proceedings, and rate design.

MS. HOLT: I move that the joint testimony of James Singer and David Williamson, consisting of 25 pages, be copied into the record as if given orally from the stand and that -- that includes their two appendices.

COMMISSIONER BROWN-BLAND: All right. Hearing no objection, that joint testimony is -- is admitted into evidence and treated as if given orally from the witness stand.

(Whereupon, the prefiled direct joint testimony and Appendix A and B of James M. Singer and David M. Williamson were copied into the record as if given from the stand.)

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

DOCKET NO. G-5, SUB 632 In the Matter of Consolidated Natural Gas Construction and Redelivery Services Agreement Between Public Service Company of North Carolina, Inc., and Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina DOCKET NO. G-5, SUB 634 In the Matter of Modification of Existing Programs and Approval of New Conservation Programs Between Public Service Company of North Carolina, Inc., and Virginia Electric and Power Company, d/b/a Dominion Energy North Carolina	JOINT TESTIMONY OF JAMES M. SINGER AND DAVID M. WILLIAMSON PUBLIC STAFF – NORTH CAROLINA UTILITIES COMMISSION

BEFORE THE NORTH CAROLINA UTILITIES COMMISSION

DOCKET NO. G-5, SUB 632
DOCKET NO. G-5, SUB 634

JOINT TESTIMONY OF

JAMES M. SINGER AND DAVID M. WILLIAMSON

ON BEHALF OF THE PUBLIC STAFF
NORTH CAROLINA UTILITIES COMMISSION

SEPTEMBER 23, 2021

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

A. My name is James M. Singer and my business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Utilities Engineer with the Energy Division of the Public Staff - North Carolina Utilities Commission.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are attached as Appendix A to this testimony.

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

A. My name is David M. Williamson and my business address is 430 North Salisbury Street, Dobbs Building, Raleigh, North Carolina. I am a Utilities Engineer with the Energy Division of the Public Staff - North Carolina Utilities Commission.

Q. WOULD YOU BRIEFLY DISCUSS YOUR EDUCATION AND EXPERIENCE?

A. Yes. My education and experience are attached as Appendix B to this testimony.

Q. WHAT IS THE PURPOSE OF YOUR JOINT TESTIMONY?

A. The purpose of our testimony is to present to the Commission the Public Staff's recommendations regarding Public Service Company of North Carolina, Inc.'s (PSNC or the Company) proposed Energy Efficiency (EE) Portfolio. Our review includes an evaluation of the following topics:

- The Company's historical operation of its EE portfolio;
- The Company's proposed new and modified programs, and continuation of its Conservation Education Program without modification;
- The Company's cost effectiveness calculations including the inputs; and
- The Company's evaluation, measurement, and verification (EM&V) of its programs.

Q. WHAT GENERAL STATUTES, COMMISSION RULES, AND COMMISSION ORDERS HAVE YOU APPLIED IN YOUR REVIEW OF THE COMPANY'S APPLICATION FOR APPROVAL OF ITS PORTFOLIO OF EE PROGRAMS?

A. Since there is not a statute or Commission rule that specifically addresses natural gas EE, the Public Staff has reviewed the Company's application in a similar manner to how it would review the programs of an investor-owned electric utility (electric IOU) EE program. Commission Rule R6-95 contains guidelines for programs designed to incent the use of natural gas (both EE and non-EE related). This Commission Rule, along with N.C. Gen. Stat. § 62-133.9 and Commission Rules R8-68 and 69 were used to help guide our investigation and to create a framework by which to evaluate the Company's proposal.

The Public Staff also reviewed previous Commission orders involving natural gas EE programs, including Docket No. G-5, Sub 495A. Within the Sub 495A docket, we reviewed the Annual Conservation Program Reports for program years 2009 through 2020.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATIONS.

A. With respect to the Company's natural gas EE programs, the Public Staff recommends that the Commission:

1) Approve the proposed modifications to its Energy Efficient Equipment Rebate Program and High Efficiency Discount Rate Program.

2) Approve the proposed Residential New Construction Program, Home Energy Report Program, and Residential Low-Income Program.

3) Reject the Company's request to remove the costs of the High Efficiency Rate Discount program from base rates, and require that the costs of the program remain in base rates.

4) Approve the Company's proposal to remove the remaining costs of all of its other EE programs from base rates and allow PSNC to recover those costs through an annual rider.

5) Require the Company to split the Energy Efficient Equipment Rebate Program into separate Residential and Commercial programs for cost allocation purposes.

6) Approve the Company's portfolio of natural gas EE programs, including the currently existing Conservation Education Program, as pilot programs to collect operational data, perform EM&V, and assess cost-effectiveness.

7) Require the Company to conduct more rigorous EM&V during the pilot period, including both process and impact evaluations, and to determine and include appropriate Net-to-

Gross (NTG) assumptions for each program and inputs associated with avoided cost.

8) Approve these pilot programs for a period of three years, to commence within six months of the Commission's final order in this docket. At the end of the pilot period or sooner, if program performance dictates, the Company should for each program seek either approval as a full program (with appropriate modifications) or termination. Any petition for full approval or termination should include supporting testimony on the updated inputs for participation, savings, NTG ratio, avoided costs, program costs, and cost-effectiveness test results.

The Company's Historical Natural Gas EE Programs

Q. HAS THE COMPANY OFFERED NATURAL GAS EE PROGRAMS IN THE PAST?

A. Yes. The Company has previously offered to customers the Conservation Education Program, Energy Efficient Equipment Rebate Program[1], High Efficiency Discount Rate Program[2], and In-

[1] In its 2021 Sub 495A report, PSNC calls this program the Energy Efficient Equipment Rebate Program, while PSNC witness Herndon's Exhibit 2 calls the program the Energy Efficiency Rebate Program, and the proposed Rider F attached to PSNC witness Hinson's testimony refers to the program as the Energy Efficiency Equipment Rebate Program. The Public Staff will refer to the program as the Energy Efficient Equipment Rebate Program in this testimony.

[2] In its 2021 Sub 495A report, PSNC calls this program the High Efficiency Discount Rate Program, as does the proposed Rider F attached to PSNC witness Hinson's testimony. PSNC witness Herndon's Exhibit 2 calls the program the High Efficiency

Home Energy Audit Program. The Commission originally approved these programs in Docket No. G-5, Sub 495A, on March 20, 2009.[3] The Commission granted the Company's petition to discontinue the In-Home Energy Audit Program on February 9, 2016 due to poor cost-effectiveness results and declining participation.[4]

Q. PLEASE DESCRIBE THE COMPANY'S CURRENT PORTFOLIO OF PROGRAMS.

A. The Conservation Education Program provides conservation education to elementary school classes in PSNC's service territory through a third party provider, the National Theatre for Children.

The Energy Efficient Equipment Rebate Program provides rebates to PSNC's North Carolina residential and commercial customers who purchase and install qualifying high efficiency natural gas heating and water heating equipment to replace existing natural gas equipment.

The High Efficiency Discount Rate Program encourages construction of homes and commercial buildings that are substantially more

Discount Program. The Public Staff will refer to the program as the High Efficiency Discount Rate Program in this testimony.

[3] *In the Matter of Application of Public Service Company of North Carolina, Inc., for Approval of Conservation Programs*, Order Approving Conservation Programs, Docket No. G-5 Sub 495A, (N.C.U.C. March 20, 2009) (Approval Order).

[4] *In the Matter of Application of Public Service Company of North Carolina, Inc., for Approval of Conservation Programs*, Order Approving Conservation Program Modifications, Docket No. G-5 Sub 495A, (N.C.U.C. February 9, 2016) (Modification Order).

energy efficient than those built to building code standards, and in return, offers natural gas at a discounted rate to customers occupying those buildings.

Q. HOW HAS THE COMPANY RECOVERED THE COSTS FOR THESE PROGRAMS?

A. Since the programs' inception, the Company recovered its costs from customers through the Company's base rates. PSNC incurred $795,369 in 2020 for program development, marketing, rebates, and EM&V for these programs.

Q. HAS THE COMPANY FILED ANY REPORTS ON THESE PROGRAMS?

A. Yes. The Company files an annual report on the programs that covers a number of topics for each program such as the administration budget, total number of measures/rebates installed, satisfaction surveys, estimated annual therm reductions, and cost-effectiveness results. [5]

[5] The most recent PSNC annual report was filed in Docket No. G-5, Sub 495A, on March 31, 2021 (2021 Annual Report).

The Company's Proposal for Natural Gas EE Programs

Q. WHAT CHANGES DOES THE COMPANY PROPOSE IN DOCKET NO. G-5, SUB 632 FOR ITS PORTFOLIO OF EE PROGRAMS?

A. The Company has not proposed any changes to its Conservation Education program. The Company is proposing to expand the Energy Efficient Equipment Rebate Program and the High Efficiency Discount Rate Program and is also requesting approval for three new Natural Gas EE programs: Residential New Construction Program, Home Energy Report Program, and Residential Low Income Program.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED MODIFICATIONS TO ITS EXISTING PROGRAMS.

A. The Company plans to expand the <u>Energy Efficient Equipment Rebate Program</u> to include additional measures, including smart thermostats and high efficiency natural gas commercial food service equipment. The Energy Efficient Equipment Rebate program includes both Residential and Non-Residential measures.

The Company proposes to modify its current <u>High Efficiency Discount Rate Program</u> to include homes that meet the North Carolina High Efficiency Residential Option (HERO) Code, as well as Energy Star certified homes and Leadership in Energy and

Environmental Design (LEED) commercial buildings to which it currently applies.

Q. PLEASE DESCRIBE THE COMPANY'S PROPOSED NEW PROGRAM OFFERINGS.

A. The <u>Residential New Construction Program</u> provides financial incentives to participating builders who construct more energy efficient homes through the installation of eligible measures. Builders can participate in one of two paths: 1) a whole home path that requires homes to meet or exceed the HERO standards; or 2) an individual equipment path with incentives offered based on the installation of qualifying natural gas equipment in the home.

The <u>Home Energy Report Program</u> will encourage behavioral changes by providing customized reports on how participants' energy use compares with other customer homes in the area. The reports will also provide tips on how to best manage energy use, save on monthly gas bills, and participate in other PSNC EE programs.

The <u>Residential Low Income Program</u> will offer in-home site visits that include an assessment of energy efficiency improvements, and then the direct installation of natural gas saving measures, including both low cost, easily installed measures such as high efficiency showerheads, faucet aerators, and hot water pipe insulation, as well as higher-cost, more labor-intensive measures such as air sealing, duct sealing, and additional insulation.

Cost Effectiveness

Q. PLEASE EXPLAIN HOW COST EFFECTIVENESS IS DETERMINED.

A. The cost effectiveness of measures or programs is generally measured by comparing the ratio of the costs to the benefits using four different tests: the Utility Cost test (UC), Total Resource Cost test (TRC), Participant test, and Ratepayer Impact Measure (RIM) test. Each test focuses on a different perspective and may include different costs and benefits, and as a result, a program may have a cost effectiveness score above 1.0 on one or more tests (the benefits outweigh the costs), and below 1.0 on other tests (the costs outweigh the benefits). In its review of electric EE programs and measures, the Public Staff currently uses the UC test to screen for cost-effectiveness, but also considers the TRC test. The Public Staff has used this same approach in reviewing the natural gas EE programs.

The TRC test considers the net benefit or cost of an EE program as a resource option based on the total costs of the program, including both the participants' and the utility's costs, as well as the benefits of the program, typically measured using the utility's avoided costs. Likewise, the UC test measures benefits and costs, but on the cost side only takes into account the costs incurred by the utility. A UC test result greater than 1.0 indicates that the program is cost beneficial to the utility (the overall system benefits are greater than the utility's costs, including incentives paid to participants), thus lowering the aggregate cost (and revenue requirement) of providing utility service. The Participant test evaluates the benefits and costs specific to those ratepayers who participate in a program, looking at the impact of participants' bills. The RIM test assesses how the program affects ratepayers who do not participate.

Q. WHAT TEST DID THE COMPANY USE TO DETERMINE COST EFFECTIVENESS FOR ITS PORTFOLIO OF NATURAL GAS EE PROGRAMS?

A. The Company utilized the UC test as the primary test for its determination of program cost effectiveness of its new EE portfolio.

Q. HOW DID THE COMPANY ANALYZE THE COST EFFECTIVENESS OF ITS PROGRAMS?

A. The Company contracted the services of Nexant, Inc. (Nexant) to perform the cost effectiveness modeling for the Company's portfolio of Natural Gas EE programs.

Q. PLEASE DESCRIBE THE RESULTS OF THE COST EFFECTIVENESS ANALYSIS AS CONTAINED IN THE COMPANY'S APPLICATION.

A. The Company's cost effectiveness results are:

Portfolio Cost-Benefit Results								
Program	Total Resource Cost		Participant Cost Test		Utility Cost Test		Ratepayer Impact Measure	
	NPV	B/C	NPV	B/C	NPV	B/C	NPV	B/C
EE Rebates	-$509,688	1.0	$10,583,036	2.3	$3,814,144	1.6	-$15,296,147	0.3
Conservation Education	-$395,528	0.3	$337,643	99.9	-$395,528	0.3	-$739,442	0.1
Home Energy Reports	$6,424	1.0	$1,829,442	99.9	$6,424	1.0	-$1,857,456	0.3
Residential New Construction	-$1,135,784	0.8	$6,073,825	2.4	$51,723	1.0	-$8,501,866	0.3
High Efficiency Discount	$3,686,767	44.8	$6,424,415	99.9	$1,938,291	2.1	-$4,742,992	0.3
Residential Low Income	-$204,384	0.9	$1,946,324	2.8	-$204,384	0.9	-$2,824,509	0.2
Totals	**$1,447,808**	**1.1**	**$27,194,683**	**3.0**	**$5,210,671**	**1.3**	**-$33,962,412**	**0.3**

Based on the Company's analysis, the Energy Efficient Equipment Rebate Program, Home Energy Report Program, Residential New Construction Program, and High Efficiency Discount Program are cost-effective under the UC test, and the Home Energy Report Program and High Efficiency Discount Rate Program are cost-effective under the TRC test.

Q. BASED ON YOUR REVIEW OF THE COMPANY'S COST EFFECTIVENESS ANALYSIS, DO YOU HAVE ANY CONCERNS?

A. For purposes of this proceeding, the Public Staff believes that the Company's calculations and cost-effectiveness test results are sufficient for approval of the programs as part of a pilot; however, we do have concerns with some of the inputs that feed into the calculations, and the Public Staff will carefully review these inputs as part of the evaluation of the pilot.

Q. WHAT ARE YOUR CONCERNS WITH THE INPUTS TO THE COST EFFECTIVENESS ANALYSIS?

A. As stated above, the Company has been offering EE programs (Energy Efficient Equipment Rebate, High Efficiency Discount Rate Program, and Conservation Education Program) to its customers for over a decade. The Public Staff's review of the program evaluation information provided in the annual reports has revealed two major concerns with some of the inputs currently used.

Over ten years have elapsed since the Approval Order, and it appears that the Company has not performed any comprehensive EM&V or reviewed its original assumptions regarding the appropriate NTG ratio. The Company continues to use gross savings, instead of applying an NTG ratio for each program measure included in the proposed EE portfolio.

Through discovery, the Company indicated that it based measure savings upon estimates, and it has not performed any EM&V on its portfolio of programs to determine savings since program inception.

The Public Staff has significant reservations with the use of gross savings, which is essentially a universal NTG ratio of 1.0. Recent electric utility EM&V reports for EE programs that offer electric versions of similar measures to those offered by PSNC's programs report an NTG ratio of less than 1.0. Given these reservations, it is appropriate to utilize other EM&V data that could serve as a proxy for the Company conducting its own battery of NTG-related surveys. For example, EM&V of similar EE programs offered by the electric IOUs, or comparable natural gas utility programs, could provide an initial estimate of NTG until the Company conducts its own EM&V, or, alternatively, be incorporated into the Company's EM&V if the participant data is shown to be comparable. The Public Staff has agreed with the use by electric membership cooperatives of EE savings and inputs from the EM&V results of similar electric IOU EE programs to comply with N.C. Gen. Stat. § 62-133.8. Such proxy data suggest that overall program level NTG ratios may be in the range of 0.65-0.75.[6]

The second concern is with the application and determination of avoided cost benefits in the model. The Public Staff has significant experience with the establishment of the avoided cost benefits utilized in an EE program's cost benefit analysis. Over the last ten years, the electric IOUs have used avoided cost benefits in their cost effectiveness evaluations, based on their integrated resource

[6] *See* EM&V for the Residential and Non-Residential Smart Saver Programs, Docket No. E-7, Sub 1230, Evans Exhibit E. Nexant performed this EM&V report.

planning and PURPA-related[7] avoided cost proceedings. However, the natural gas utilities do not have a similar proceeding to establish avoided costs, including appropriate calculation methodologies.

For this proceeding, the Company developed avoided cost benefits to calculate the cost-effectiveness of the EE programs. The Public Staff continues to evaluate these inputs and the methodology associated with avoided cost benefits. However, with the exception of the High Efficiency Discount Rate program, for purposes of this proceeding and for considerations of program approval, the Public Staff does not object to the Company's inputs and calculations. In future proceedings involving cost effectiveness for natural gas EE programs, the Public Staff recommends that the Commission require the Company to file testimony that explains the reasonableness of all proposed avoided costs that are included in its analysis.

Q. ARE THERE OTHER CONCERNS WITH THE PORTFOLIO THAT YOU WOULD LIKE TO DISCUSS?

A. Yes. Our investigation of the existing and proposed portfolio of programs has raised concerns with the following:

1) The Company's proposal to offer measures to both Residential and Commercial customers in its Energy Efficient

[7] Public Utility Regulatory Policies Act (PURPA, Pub. L. 95–617, 92 Stat. 3117, enacted November 9, 1978).

Equipment Rebate Program, without addressing the appropriate level of cost recovery for each class;

2) The Company's High Efficiency Discount Rate Program and its potential for dual counting of benefits;

3) The interaction between the Company's High Efficiency Discount Rate program and the Residential New Construction Program.

Q. PLEASE EXPLAIN YOUR CONCERNS WITH THE ENERGY EFFICIENT EQUIPMENT REBATE PROGRAM.

A. The Public Staff does not have concerns with the Company offering a cost-effective Energy Efficient Equipment Rebate program to its customers. However, to ensure appropriate assignment of costs to rate classes, the Public Staff recommends that the Company split the Energy Efficient Equipment Rebate Program into two separate programs, a Residential and a Commercial program.

Q. PLEASE EXPLAIN YOUR CONCERNS REGARDING THE HIGH EFFICIENCY DISCOUNT RATE PROGRAM AND ITS INTERACTION WITH THE RESIDENTIAL NEW CONSTRUCTION PROGRAM.

A. The High Efficiency Discount Rate program originally offered discounted rates to residential and commercial customers whose dwellings or commercial buildings met qualifying standards and who provided proof of qualification. The qualifying standards of the program at the time were Energy Star or equivalent dwellings, and LEED or equivalent commercial buildings. The Modification Order allowed PSNC to remove the equivalency standards due to administrative difficulties. In this proceeding, the Company is proposing to expand the qualifications of this High Efficiency Discount Rate program to include dwellings built in accordance with the HERO code.

Additionally, the Company in this proceeding has proposed to begin offering a Residential New Construction program. This program, as described earlier in our testimony, focuses on building homes in accordance with the HERO code.

Due to the nature of the program's qualifications, homes constructed under the Residential New Construction Program will then be eligible for the High Efficiency Discount Rate Program.

Having two programs that rely on the same building code qualification and, thus, act concomitantly, will make it difficult to determine which program should be assigned credit for the achieved savings from measures installed, and could lead to one or both programs failing to achieve cost-effectiveness. In other words, the savings generated from the Residential New Construction program should not be counted in the cost benefit analysis of the Company's High Efficiency Discount Rate program.

Q. CAN THIS POTENTIAL FOR DOUBLE COUNTING OF THE BENEFITS OCCUR ELSEWHERE IN THE PORTFOLIO?

A. Yes, the same overlap can occur between the High Efficiency Discount Rate Program and the Energy Efficient Equipment Rebate Program. A home currently on the discount rate remains eligible to participate in the rebate program. Thus, for purposes of cost effectiveness evaluations, PSNC should not claim energy savings for the High Efficiency Discount Rate program resulting from equipment replaced via the Energy Efficient Equipment Rebate program.

Q. BASED ON YOUR CONCERNS OUTLINED ABOVE, WHAT IS YOUR RECOMMENDATION AS TO APPROVAL OF THE COMPANY'S PORTFOLIO OF PROGRAMS?

A. The Public Staff has promoted, and will continue to promote, cost effective EE offered to customers through utility-sponsored programs. However, the Public Staff must ensure that the inputs used to model cost effectiveness result from sound assumptions based on relevant and contemporaneous data applicable to the Company's service territory. Additionally, since avoided costs are the primary determinant of benefits for a program, the assumptions and inputs used to calculate the benefits are critical elements in the review of program cost effectiveness.

Based on our review, we conclude that the Company's approach to modeling the programs is sound, but the inputs need to be updated to reflect more accurate data. With the exception of the Company's High Efficiency Discount Rate program, the Public Staff recommends approval of the Company's portfolio of programs (those included in this filing as well as the Conservation Education Program), as pilot programs for a three-year period. Operating the programs as pilots will allow the Company time to conduct EM&V and use the information gathered to refine its inputs, assumptions, and calculations of cost effectiveness.

During this three-year period, the Company should work to evaluate and broaden its efforts to market and educate its customers about EE, increase participation in the programs, and evaluate the performance of the programs. The Public Staff also encourages the Company to seek Commission approval of the pilot as a full program before the end of the three-year period if participation and performance demonstrate satisfactory cost effectiveness. Conversely, with the exception of Residential Low-Income Program, if any pilot measure or program is underperforming and cannot be satisfactorily remediated, the Company should seek to terminate the measure or program before the end of the three-year period.

Additionally, the Public Staff strongly encourages the Company to pursue ways to address and enhance its delivery of EE measures to residential low income customers.

Q. PLEASE EXPLAIN YOUR RECOMMENDATION FOR THE COMPANY'S HIGH EFFICIENCY DISCOUNT RATE PROGRAM.

A. Since it may be difficult for the High Efficiency Discount Rate program to generate savings apart from savings resulting from the Residential New Construction program or other EE programs, the Public Staff recommends that this program remain in the Company's base rates at this time, rather than being included in the Company's EE portfolio as an EE program.

<u>Evaluation, Measurement, and Verification</u>

Q. PLEASE DESCRIBE THE COMPANY'S PAST EFFORTS IN THE AREAS OF EM&V.

A. As stated earlier, the Company currently files an annual report that provides a description of each program, summary of the measures involved along with the applicable measure efficiency standards, the number of participants for each measure, program expenditures, and therm savings. While these reports have met past Commission requirements, the Public Staff believes that as the Company expands its offerings and seeks annual recovery through a rider, the Company should increase the level of rigor in its examination of program performance.

Q. WHAT EM&V IS THE COMPANY PROPOSING FOR THESE NEW OR MODIFIED PROGRAMS?

A. In response to discovery, the Company stated:

> The Company has not yet developed EM&V plans for each program. The budgets for the proposed programs include EM&V allocation and anticipate that both impact and process evaluations will be conducted for each program over the initial 5-year program period included in the cost-benefit analysis. Impact evaluation activities are expected to focus on verifying savings in each program and may include billing analysis, engineering calculations, and primary data collection. Process evaluation activities are expected to focus on the operations of the program and customer attitudes and engagement.

Q. DOES THE PUBLIC STAFF AGREE WITH THE COMPANY'S APPROACH TO EM&V?

A. In the context of gas utility regulation, EM&V has not been emphasized to the same extent as it has for regulated electric utilities and unregulated utilities subject to N.C. Gen. Stat. § 62-133.8. The natural gas utilities do not receive a financial incentive as provided to the electric IOUs based on the savings achieved by their EE programs, as determined through EM&V.

The Approval Order discusses evaluation of EE programs in more detail:

> The Commission notes that PSNC did not provide a definition of the "Utility Cost Test," and did not state the Utility Cost Test's assumptions or offer details to support the Company's findings. The Commission is generally familiar with the concept of a Utility Cost Test and no party protested the lack of supporting information with PSNC's filings. The Public Staff noted that the cost-effectiveness of the proposed programs, as estimated by PSNC, are dependent upon several key untested variables and assumptions and therefore the actual cost-effectiveness of the programs could differ from PSNC's estimates. The Public Staff commented that it believes that PSNC's proposed programs, as revised, appear to be reasonable in that they offer customers tangible ways to conserve natural gas.[8]

The Public Staff supports the Company's path toward EM&V planning and is committed to working with the Company to refine the process to ensure that it is able to determine "net" program savings for each program. The fact that the Company has not fully developed its evaluation plans provides further support for the Public Staff's recommendation that the Commission approve the programs as pilots.

Q. DOES THIS CONCLUDE YOUR TESTIMONY?

A. Yes.

[8] *Order Approving Conservation Programs*, Docket G-5 Sub 495A (March 20, 2009).

APPENDIX A

JAMES M. SINGER

I am a graduate of Penn State University with a Bachelor of Science degree in Mechanical Engineering. Upon graduation, I worked as a Station Engineer at FirstEnergy Corp., responsible for maintaining, troubleshooting, and optimizing unit equipment and operations. I also held positions as a Project Engineer and as an Analyst in FirstEnergy's Commodity Operations group, where I performed benefit-cost analysis for projects throughout the company.

In 2008, I accepted a position with Progress Energy as a Boiler Engineer, responsible for operational and reliability issues for two top-tier boilers and performing boiler inspections across the Progress Energy fleet.

After Progress Energy's merger with Duke Energy, I transitioned to a Project Manager role, focusing on gas turbine overhaul and generator repair projects.

In 2020, I worked as Consulting Engineer with Novo Nordisk in Clayton, NC, on the DAPI-US project - the largest pharmaceutical manufacturing project in the world. I was responsible for reviewing turnover documentation from the general contractor and troubleshooting operating systems.

I joined the Public Staff Energy Division in March of 2021.

APPENDIX B

QUALIFICATIONS AND EXPERIENCE

DAVID M. WILLIAMSON

I am a 2014 graduate of North Carolina State University with a Bachelor of Science Degree in Electrical Engineering. I began my employment with the Public Staff's Electric Division in March of 2015. In August of 2020, the Electric Division merged with the Natural Gas Division to form the Energy Division, where I am a part of the Electric Section – Rates and Energy Services. My current responsibilities include reviewing applications, making recommendations for certificates of public convenience and necessity of small power producers, master meters, and resale of electric service, and interpreting and applying utility service rules and regulations. Additionally, I am currently serving as a co-chairman of the National Association of State Utility and Consumer Advocates' (NASUCA) DER and EE Committee.

My primary responsibility within the Public Staff is reviewing and making recommendations on DSM/EE filings for initial program approval, program modifications, EM&V evaluations, and ongoing program performance of DEC, DEP, and DENC's portfolio of programs. I have filed testimony in various DEC, DEP, and DENC DSM/EE rider proceedings, as well as recent general rate case proceedings.

MS. HOLT: Thank you.

COMMISSIONER BROWN-BLAND: All right. Does that bring us to the close? I believe all evidence is in and received.

(No response.)

COMMISSIONER BROWN-BLAND: All right. Anything else to come before the Commission before we deal with the procedural matters?

(No response.)

COMMISSIONER BROWN-BLAND: Hearing nothing --

MS. HOLT: No, ma'am.

COMMISSIONER BROWN-BLAND: All right. Thank you. Hearing nothing, the proposed orders and briefing, if you -- and briefs, if you choose to submit them, is it good with all parties that they be due 30 days after the filing of the transcript?

MS. HOLT: Yes.

MS. GRIGG: Yes, ma'am.

COMMISSIONER BROWN-BLAND: All right. Anyone identified --

MS. CRESS: I apologize.

COMMISSIONER BROWN-BLAND: Oh, I -- I'm glad you stepped up, because I asked you not to let me forget. Ms. Cress?

MS. CRESS: Yes. Thank you, Presiding Commissioner Brown-Bland, and my apologies for having to amend the earlier motion.

Would it -- would the Commission prefer that I simply amend the -- the two edits or would it be easier for clarity of record if -- if I just redo the motion?

COMMISSIONER BROWN-BLAND: Just restate what it is we're -- we have received and are admitting into evidence.

MS. CRESS: Absolutely. Thank you, Commissioner.

I would re-move that witness Collins' prefiled direct testimony filed in the docket on September 23rd, 2021, consisting of 21 pages, including a cover sheet and an appendix, be admitted and copied into the record as if given orally from the stand, and additionally move that witness Collins' direct exhibit marked as BCC 1 through BCC 8 be admitted and entered into the record. Thank you.

COMMISSIONER BROWN-BLAND: All right. That motion is allowed and clarified for the record. Thank you, Ms. Cress.

MS. CRESS: Thank you.

COMMISSIONER BROWN-BLAND: Now, I was just getting ready to say -- and it would have -- it would have picked up Ms. Cress anyway. Is anyone aware of anything else I'm forgetting? It's so easy to do with all this paper.

(No response.)

COMMISSIONER BROWN-BLAND: All right. I'm not hearing any. I think we've come to the close, and that being the case, we will stand adjourned. Thanks, everyone.

(The hearing was adjourned at 11:11 a.m.)

STATE OF NORTH CAROLINA

COUNTY OF FRANKLIN

CERTIFICATE

I, PATRICIA C. ELLIOTT, VERBATIM REPORTER AND NOTARY PUBLIC, DO HEREBY CERTIFY THAT THE FOREGOING IS A TRUE AND ACCURATE TRANSCRIPTION OF MY VOICE WRITER NOTES AND IS A TRUE RECORD OF THE PROCEEDINGS.

I FURTHER CERTIFY THAT I AM NOT EMPLOYED BY OR RELATED TO ANY PARTY TO THIS ACTION BY BLOOD OR MARRIAGE AND THAT I AM IN NO WAY INTERESTED IN THE OUTCOME OF THIS MATTER.

IN WITNESS WHEREOF, I HAVE HEREUNTO SET MY HAND THIS 23rd DAY OF OCTOBER, 2021.

PATRICIA C. ELLIOTT
VERBATIM REPORTER/NOTARY PUBLIC
NOTARY #19940480043