

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
MARK KEMPIC
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

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1 **I. INTRODUCTION**

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

3 A. Mark Kempic, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

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

5 A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the
6 "Company") as its President and Chief Operating Officer.

7 **Q. What are your responsibilities as Columbia's President and Chief**
8 **Operating Officer?**

9 A. I am the corporate officer primarily responsible for the overall performance of
10 Columbia Gas of Pennsylvania, Inc.

11 **Q. What is your educational and professional background?**

12 A. I hold an Associate Engineering Degree in Solar Heating and Cooling Technology
13 from the Pennsylvania State University, a Bachelor of Science Degree in Computer
14 Science from the University of Pittsburgh and a Juris Doctor from the Capital
15 University Law School in Columbus, Ohio. I held various positions within Columbia
16 and its parent company from 1979 through 1992 including emergency service
17 dispatcher, engineering technician, information systems analyst, gas supply and
18 corporate planning analyst. From 1992 through 1994, I worked at a law firm where
19 I represented the interests of industrial customers in utility regulatory proceedings
20 before the Public Utilities Commission of Ohio, and from 1994 until my return to

1 Columbia, I worked as in-house state regulatory counsel for an electric company in
2 Cleveland, Ohio. After rejoining Columbia in 1998, I served as an attorney and was
3 subsequently promoted to senior attorney and then assistant general counsel. In
4 October of 2009, I was named Director of Rates and Regulatory Policy for
5 Columbia. I served as President from 2012 until 2017, at which time I accepted a
6 position as the Chief Transformation Officer for NiSource Inc. ("NiSource"). In the
7 fall of 2018, I relocated to Massachusetts at first in a temporary capacity, and then I
8 was named President and Chief Operating Officer of Columbia Gas of
9 Massachusetts, a position I held until August of 2020. I resumed my role as
10 President of Columbia Gas of Pennsylvania in September of 2020.

11 **Q. Have you ever testified before a regulatory Commission?**

12 A. Yes, I have testified before both the Pennsylvania Public Utility Commission
13 ("Commission") as well as the Maryland Public Service Commission. Previously, I
14 testified in Columbia's numerous base rate cases before the Commission at Docket
15 Nos. R-2009-2149262, R-2010-2215623, R-2012-2321748, R-2014-2406274, R-
16 2015-2468056, R-2016-2529660, R-2021-3024296, R-2022-3031211, and R-2024-
17 3046519.

18 **Q. Please describe the scope of your testimony in this proceeding.**

19 A. Through my testimony, I will provide the Commission with an overview of this base
20 rate filing, and discuss the objectives that Columbia seeks to accomplish in this
21 proceeding. I will also introduce Columbia's other witnesses who provide detailed

1 testimony and supporting documentation for all revenues, expenses and rate base
2 elements included in the Fully Projected Future Test Year ("FPFTY") in this base
3 rate filing.

4 **Q. Please describe briefly the corporate history of Columbia and its**
5 **relationship with its parent company, NiSource.**

6 A. Columbia was incorporated on June 23, 1960 as a wholly-owned subsidiary of the
7 Columbia Gas System, Inc., under the Act of May 29, 1885, P.L. 29 of the
8 Commonwealth of Pennsylvania and commenced service as Columbia Gas of
9 Pennsylvania, Inc., on January 1, 1962, when it acquired the Pennsylvania retail
10 business of The Manufacturers Light and Heat Company, which was at that time
11 another wholly-owned subsidiary of The Columbia Gas System, Inc. In 1998, the
12 Columbia Gas System, Inc. became the Columbia Energy Group ("CEG"). In turn,
13 CEG merged with NiSource in 2000, at which time Columbia became one of ten
14 (10) natural gas distribution companies in the NiSource corporate family as it
15 existed at that time. Columbia is engaged in the business of delivering natural gas
16 service to approximately 446,000 residential, commercial, and industrial customers
17 pursuant to certificates of public convenience and necessity issued by the
18 Commission. Columbia has its principal office in Canonsburg, Pennsylvania, and
19 provides natural gas distribution service in portions of 26 counties in Pennsylvania,
20 primarily in the western half of the state, as well as parts of Northwest, Southern
21 and Central Pennsylvania.

NiSource, headquartered in Merrillville, Indiana, is an energy holding company whose subsidiaries provide natural gas and electricity distribution services to approximately 3.8 million customers. NiSource is the successor to an Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource Inc. on April 14, 1999. In connection with the acquisition of CEG on November 1, 2000, NiSource became a Delaware corporation registered under the Public Utility Holding Company Act of 1935, which has since been replaced by the Public Utility Holding Company Act of 2005.

NiSource is subject to the jurisdiction of the Securities and Exchange Commission and is traded on the New York Stock Exchange with the symbol "NI". The NiSource gas distribution companies are: Northern Indiana Public Service Company ("NIPSCO"), Columbia Gas of Kentucky, Columbia Gas of Maryland, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, and Columbia Gas of Virginia.

II. CASE OBJECTIVES

Q. Please summarize Columbia's major objectives in this proceeding.

A. Consistent with prior cases, the primary driver for this filing is Columbia's ongoing significant investment to modernize its distribution system through the replacement of pipe and related appurtenances that are reaching the end of their useful lives. Columbia seeks Commission approval to increase its base rates to recover the revenue requirement associated with the capital Columbia has invested,

1 and will continue to invest, in its facilities as part of its continued focus to prioritize
2 spend to address identified risks on our system, including our accelerated pipeline
3 replacement program, as well as Columbia's ongoing operations and maintenance
4 expenditures. Approval of the Company's request is necessary for Columbia to
5 continue to provide safe and reliable natural gas service at the lowest reasonable
6 price to its customers, while providing the Company with a reasonable opportunity
7 to recover its costs and to earn a fair rate of return. Further, approval of this
8 request will demonstrate to the investment community that the Commission
9 continues to support the need for intensified focus on pipeline safety matters as well
10 as the need for reasonable and predictable earnings. My testimony will outline, at a
11 high level, the objectives of Columbia's filing. Details and documentation
12 supporting each of the objectives will be provided by Company witnesses that I will
13 introduce later in my testimony.

14 **a. Proposed Rate Increase**

15 **Q. Will you please explain Columbia's main objective by filing this case?**

16 A. Columbia seeks recovery of, and an opportunity to earn a return on, the capital
17 investments being made in its distribution system which are necessary to provide
18 safe and reliable natural gas distribution service to its customers. In light of the
19 substantial capital investment Columbia has made and the large capital investments
20 that will be made through the end of 2026, Columbia is filing this base rate case
21 using the FPFTY as authorized under 66 Pa. C.S. § 315 in order to provide itself with

1 a reasonable opportunity to recover its investment in its distribution system and its
2 operation and maintenance (“O&M”) expenditures.

3 **Q. Why is Columbia filing a base rate case when the Distribution System**
4 **Improvement Charge (“DSIC”) is available?**

5 A. Columbia’s revenue deficiency is driven by the large capital investment that it
6 continues to make in modernizing its distribution system. Columbia’s last rate case
7 was filed in March of 2024, and since then, Columbia made \$437 million in actual
8 plant additions, and retired \$53 million, resulting in net addition of \$384 million.
9 With this net addition of \$384 million of actual plant, Columbia exceeded the level
10 of investments that it had forecasted and included in the last rate case by \$13
11 million. While Columbia continually assesses whether and when it should file a
12 DSIC, due to the scale of Columbia’s investments in replacement pipe, a DSIC alone
13 is not enough to address the revenue deficiency as Columbia’s requested overall
14 distribution (i.e., exclusive of gas costs) revenue increase in this proceeding exceeds
15 the current 5% cap for a DSIC surcharge. I would note that in 2016, Columbia
16 requested Commission approval to increase the cap on DSIC surcharges to 10%, but
17 the requested waiver was denied.

18 **Q. What is Columbia’s proposed rate increase in the case and what are**
19 **some of the primary drivers for the increase?**

20 A. Based on the rates established in Columbia’s last base rate case and Columbia’s
21 existing and planned capital and O&M programs, Columbia will experience a

1 revenue deficiency of approximately \$110.5 million, as detailed and supported in
2 testimony of Company witness Vassalotti (Columbia Statement No. 4). This revenue
3 deficiency is driven primarily by substantial capital investments Columbia has
4 made, and continues to make, in its system. As detailed in Company witness
5 Brumley's testimony (Columbia Statement No. 7), since Columbia started its
6 accelerated pipeline replacement program in 2007, Columbia has replaced
7 7,871,526 feet (over 1,491 miles) of cast iron and bare steel. During that time,
8 Columbia has also replaced 1,559,722 feet (over 295 miles) of pre-1971 ineffectively
9 coated steel pipe and 820,882 feet (over 155 miles) of pre-1982 plastic.

10 **Q. Has Columbia considered the impact of a rate increase on customers?**

11 A. The Company realizes that rate increases will always have an impact on customers;
12 however, considering the large, ongoing and growing capital program, which is
13 necessary to retire and replace aging infrastructure, a rate increase is unavoidable.
14 Columbia estimates that the total bill of an average residential customer using 70
15 therms per month will increase by \$15.77 per month. Even after this increase, the
16 average customer's total bill (including gas costs) will only be about 2% higher than
17 the average customer's total bill was *20 years ago* after you adjust for inflation.
18 This is made possible by the lower gas supply costs since 2008, which provide a rare
19 opportunity to make these safety and reliability investments in replacing pipe
20 without taking a larger share of the customer's wallet. While you cannot put a price
21 on the improvements in safety and reliability which we have brought about by our

1 investments over the last 18 years, it is good to know that we have made those
2 improvements and kept the customer's total cost reasonable and generally in line
3 with inflation. In addition to the safety and reliability benefits provided by the
4 Company's large scale pipeline replacement program, the Company believes that
5 maintaining and growing its infrastructure modernization program provides the
6 ancillary benefit of energizing the local economies through the wages paid to the
7 skilled labor necessary to complete the work. This economic boost is especially
8 important in many of the rural and economically disadvantaged communities in
9 which Columbia provides service. In addition, through these efforts, we are
10 reducing methane emissions from our main and service lines.

11 **Q. How does Columbia meet the needs of its low income customer base?**

12 A. The Company offers a number of programs to support our most vulnerable
13 customers. With its current investment level and array of programs, Columbia Gas
14 is the leader among Pennsylvania's natural gas utilities in serving and caring for our
15 most vulnerable customers. Company witness Paloney discusses our programs and
16 the number of customers that benefit from these programs in Columbia Statement
17 No. 9.

18 **b. Other Objectives**

19 **Q. Does Columbia have other objectives in this case?**

20 A. Yes. Additional objectives in this proceeding are as follows:

Establishment of a Revenue Normalization Adjustment (“RNA”)

Mechanism: Columbia proposes to implement an RNA to be used in conjunction with its Weather Normalization Adjustment (“WNA”). Through this proceeding, the Company proposes to establish a benchmark revenue level, regardless of changes in customers’ actual usage levels. Excess collections above the benchmark revenue level would be refunded to customers and amounts below the benchmark level would be recouped by the Company. Company witness Taylor will discuss the proposed RNA further in Columbia Statement No. 17.

Establish a Permanent WNA: The current WNA is a pilot program, with a 3% deadband. As part of the Company’s 2024 Rate Case at Docket R-2024-3046519, the pilot is ending one year early, and the Company is seeking a permanent WNA with a 3% deadband to be utilized in conjunction with the RNA as described above. The goal of the WNA continues to be to improve predictability and stability of the customers’ bills and to provide revenue stability. Company witness Taylor will discuss the proposed WNA further in Columbia Statement No. 17.

Renew Residential Energy Efficiency Program and Establish a New Commercial Energy Efficiency Program: The Company’s Pilot Residential Energy Efficiency Program is set to expire at the end of 2025. The Company is seeking to continue the current program while adding additional residential measures and a commercial component to the overall program for a period of

1 three years. Company witness Nunley will discuss these programs further at
2 Columbia Statement No. 13.

3 **Introduction of the Economic Development Distribution Service**

4 **(“EDDS”) Rate:** In conjunction with Governor Shapiro’s desire to bring
5 economic development to Pennsylvania, the Company is seeking to implement this
6 new tariff provision to allow the flexibility to bring on new large load customers that
7 may have near -term natural gas needs in a manner that provides for accelerated
8 cost recovery while protecting the interests of the existing Columbia customer base.

9 This rate schedule will treat these customers as non-jurisdictional customers and
10 provide the opportunity for Columbia to enter into individual contracts with
11 customers taking service under this rate schedule. Company witness Paloney will
12 discuss this further in Columbia Statement No. 9.

13 **Inclusion of Energy Assistance Team (“EAT”) Program Labor Cost In**
14 **the Universal Services Plan (“Rider USP”):** The Company is proposing the

15 costs associated with the Company’s Energy Assistance Team, which handles all
16 energy assistance activities, to be recovered through the Rider USP. Currently, EAT
17 labor is recovered in base rates, however, the team’s sole responsibility is to provide
18 support for the Company’s assistance programs. Company witness Davis will
19 discuss this further in Columbia Statement No. 16.

20 **Customer Assistance Plan (“CAP”) Arrearage Pilot Program:** The
21 Company is seeking to implement a \$100,000 grant program to help CAP

1 customers who were removed from the program for non-payment return to the
2 program. Costs for this program will be recovered through the Rider USP.
3 Company witness Davis will discuss this further in Columbia Statement No. 16.

4 **Speech Analytic Pilot Program:** In conjunction with the provisions in the
5 settlement in Docket R-2024-3046519, the Company is seeking to implement a
6 pilot using technology to review customer calls to identify customers that may be
7 eligible for CAP and were not referred to the program during the call. The long-
8 term goal is to improve customer service representative (CSR) recognition of
9 potential low-income customers to more quickly target them for CAP. Company
10 witness Davis will discuss this further in Columbia Statement No. 16.

11 **Q. Does the Company have any other ongoing initiatives?**

12 A. Yes. The Company has accelerated its efforts to maximize efficiencies, improve
13 process discipline, reduce risk and reduce costs across the enterprise over the long-
14 term to gain sustainable capability enhancements and cost efficiency
15 improvements that reflect NiSource's commitment to safety, risk mitigation and
16 customer service.

17 Specifically, in 2023, NiSource bolstered its continuous improvement and cost
18 savings efforts by establishing a dedicated team, primarily consisting of field
19 employees, that was tasked with looking at our largest cost drivers as an
20 organization and working with subject matter experts and leadership to find
21 opportunities to improve efficiencies, lean out processes, and reduce cost. The

1 team found considerable opportunities across NiSource companies, including
2 Columbia. The team is still in existence, working continuously to improve
3 process to reduce costs.

4 In addition, over the next five years, NiSource plans to replace outdated
5 legacy IT systems with integrated, secure, and reliable systems that will benefit both
6 customers and employees. These investments are necessary to address outdated
7 systems that are at risk of failure with limited support options available to maintain
8 and protect against operational and cyber related events. Through technical reviews
9 of the current state systems, it was determined to place an initial emphasis on
10 systems that support field operations that directly support our customers. As a
11 result, the first step in this transformation is implementation of the Work and Asset
12 Management program to facilitate the planning, scheduling, dispatch, and
13 execution of the work on and management of utility assets, which will be completed
14 in 2025 and rolled out to employees. IT transformation will continue in 2026, with
15 a focus on Customer Information Systems consisting of integrating key billing
16 systems, billing updates, bill redesign and interactive self-service technologies.

17 **c. Future Infrastructure Replacement**

18 **Q. What are the Company's future plans for infrastructure replacement?**

19 A. The Company intends to continue replacement of prone to fail pipe at an
20 accelerated pace in order to retire its remaining aging infrastructures soon as
21 possible. As Columbia's infrastructure replacement program has been operating for

1 almost 18 years, substantial progress has been made on replacing bare steel and all
2 cast iron has been removed from the system. However, the Company has
3 expanded its investments beyond bare steel replacement, as warranted, due to other
4 risks identified on our system. The Company's focus on risk identification and
5 mitigation was validated with the Commission's April 20, 2023 approval of
6 Columbia's Third Long Term Infrastructure and Improvement Plan ("LTIIP") for
7 the years of 2023 to 2027. Specifically, in that proceeding the Commission
8 approved Columbia's plan to continue its focus on replacing remaining bare steel,
9 but to also expand its focus to include pre-1982 plastic (including "Adyl-A") and
10 pre-1971 ineffectively coated steel pipe as discussed in the LTIIP at Docket P-2022-
11 3037388. The prioritization of investments to address and mitigate those highest
12 identified risks is - and will continue to be - the Company's focus.

13 Columbia recognizes that gas distribution systems have been constructed
14 over many decades with a variety of material types and generations of pipes,
15 components, valves, fittings, etc., and that means Columbia will continue to endorse
16 and enhance its Safety Management System ("SMS") and its Distribution Integrity
17 Management Program ("DIMP") to identify emergent risks that need to be
18 considered and addressed. To that end, Columbia may identify additional risks that
19 warrant "priority" replacement as employees raise issues through Columbia's SMS
20 Corrective Action Program and through the detailed analyses of the distribution
21 system risks in its DIMP. While it is essential to address aging infrastructure and

respond appropriately to emergent risks, that work does not come without a cost. Figure 1 below is an excerpt from the Company's response to Standard Data Request GAS-ROR-014, showing the total net capital after retirements are netted out. I note that Columbia's ability to increase its capital investment and maintain these accelerated levels of investment is a direct result of Act 11's impact on reducing the regulatory lag that was formerly associated with utility ratemaking in Pennsylvania.

Figure 1

Capital Expenditures Net Reimbursements					
Class	2025	2026	2027	2028	2029
Growth	\$ 42,557	\$ 40,697	\$ 43,647	\$ 43,671	\$ 45,144
Betterment	\$ 14,249	\$ 26,679	\$ 25,576	\$ 7,034	\$ 5,135
Public Improvement	\$ 15,140	\$ 9,884	\$ 9,369	\$ 9,347	\$ 9,838
Replacement	\$ 312,281	\$ 335,994	\$ 366,549	\$ 396,530	\$ 425,064
Support Services	\$ 6,612	\$ 12,933	\$ 6,636	\$ 6,083	\$ 4,872
Total Net Capital	\$ 390,839	\$426,186	\$451,777	\$462,666	\$490,053

Q. What are the drivers for Columbia to continue investment in replacing aging infrastructure?

A. As shown in Figure 2 below, in terms of miles, Columbia's distribution system is the third largest in Pennsylvania as of the end of calendar year 2023 (the most current calendar year for which complete data is available at the time of the compilation of this rate case filing).

Figure 2

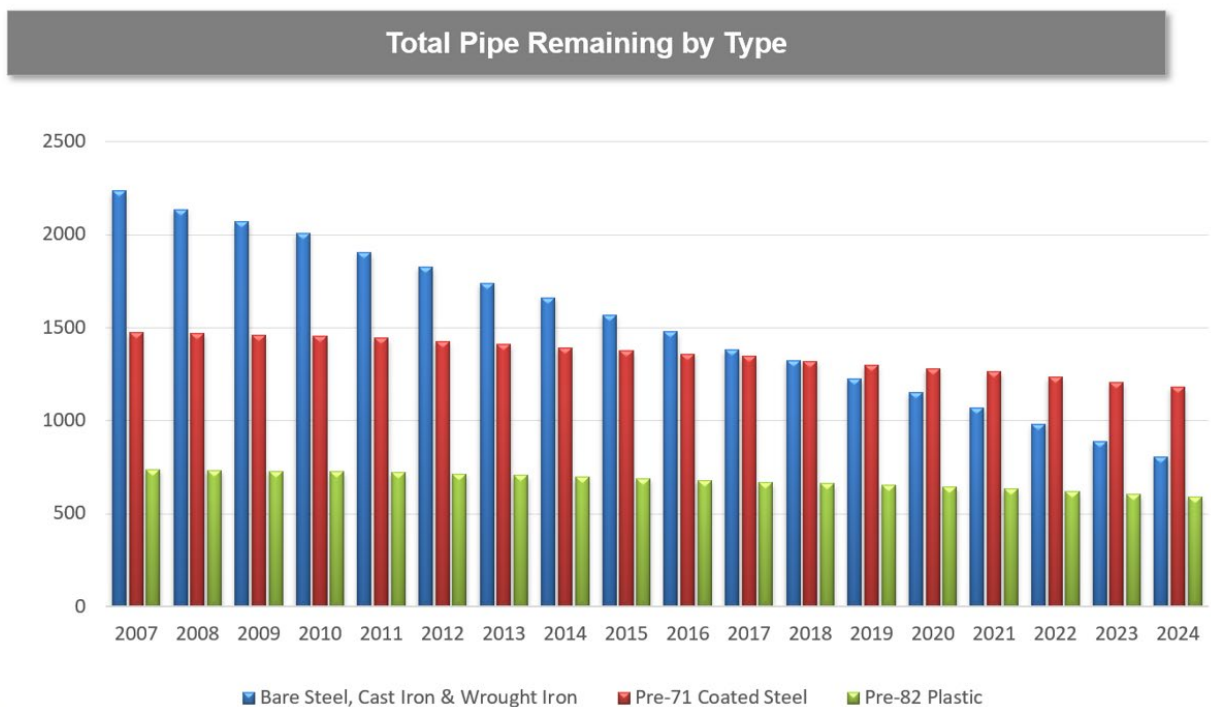
Pennsylvania LDCs – Pipeline Mileage

NGDC	Miles of Pipe (2023)
Columbia Gas	7,752.10
PGW	3,047.20
PECO	7,309.00
UGI	12,405.00
Peoples	13,112.96
National Fuel	4,832.12

The size of the Company's capital investment program is driven by the amount of pipe that needs to be maintained and ultimately replaced rather than the number of customers. Approximately 10% of Columbia's total inventory of pipe is either bare steel or wrought iron, approximately 7% is pre-1982 plastic, and approximately 14% is pre-1971 coated pipe. Both pre-1982 plastic and pre-1971 coated pipe are reaching the end of their useful lives and because Columbia has focused primarily on replacing bare steel and cast-iron pipe over the last fifteen years, the inventories of pre-1982 plastic and pre-1971 coated steel have not been substantially reduced. As explained more fully in Columbia's LTIIP, in the past when the latter two types of pipe have bordered cast iron or bare steel, the Company included them in the replacement project in order to reduce that risk, rather than leaving them in the ground and designing and executing a separate replacement project. Because Columbia's strategy under prior LTIIPs, however, was to focus on replacing cast

iron and bare steel, as shown in Figure 3 below, the inventories of pre-1982 plastic and pre-1971 coated steel have not been substantially reduced.

Figure 3
Columbia Gas Remaining Pipeline Inventories

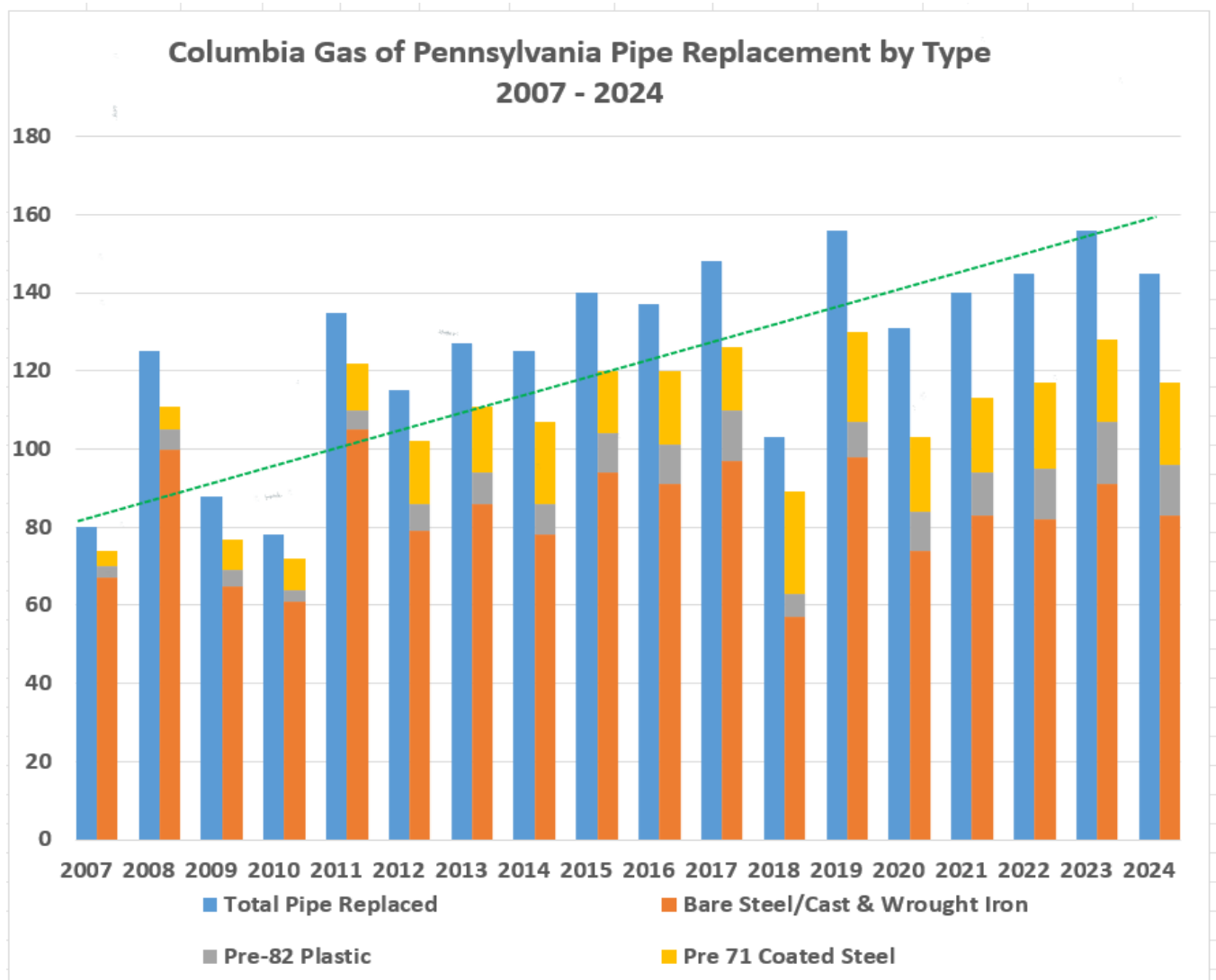


Under Columbia's Commission-approved third LTIP, it is now time to focus on replacing these types of pipes even if they are not adjacent to a bare steel replacement project to reduce the risk associated with these pipe inventories. It makes sense to do it now before the pipe fails, and while gas prices remain relatively low in Pennsylvania. Therefore, in addition to reducing risk by replacing this pipe now, the customer's total gas bill will continue to be affordable.

Q. What is the Company's history of retired bare steel and cast-iron pipe?

A. See Figure 4 below for the Company's history of infrastructure replacement compared to total pipe replaced since 2007, which was the first year the Company began replacing pipe at an accelerated rate.

Figure 4



1 **Q. Discuss the Company's infrastructure replacement program levels over**
2 **the past few years.**

3 A. As Figure 4 above indicates, following a decrease in 2021, the Company resumed its
4 normal performance levels by replacing 82 miles of bare steel, cast iron and
5 wrought iron in 2022. In 2023 the Company replaced 91 miles of bare steel, cast
6 iron and wrought iron, then in 2024 the Company replaced 83 miles of bare steel
7 and wrought iron, 13 miles of pre-1982 plastic and 21 miles of pre-1971 coated steel,
8 for a total of 117 miles of pipe replaced.

9 **d. Other Enhancements to Infrastructure Replacement Efforts**

10 **Q. As your replacement program has progressed, how is Columbia**
11 **enhancing its approach to infrastructure replacement?**

12 A. Through our own experiences beginning in 2007 when we began to accelerate
13 infrastructure replacement, and through the experiences learned from other
14 Columbia companies across the NiSource footprint, the Company is expanding the
15 focus of risk reduction beyond the replacement of aging infrastructure.

16 **Q. How has the Company expanded risk identification?**

17 A. The Company has a well-established Safety Management System ("SMS") pursuant
18 to American Petroleum Institute Recommended Practice (or "RP") 1173. RP-1173
19 provides guidance to pipeline operators for developing and maintaining a pipeline
20 safety management system and is intended to augment existing practices while not
21 duplicating any other requirements. Furthermore, NiSource received its

1 International Organization for Standardization (ISO) 55001 Asset Management
2 certification in 2023. This ISO standard details the criteria required for
3 establishing, implementing, maintaining, and improving asset management. The
4 Asset & Risk Management (“A&RM”) group evaluates asset health, asset life cycle,
5 asset risks and mitigation efforts to reduce top risk drivers.

6 **Q. Can you provide an example of how SMS has impacted the Company’s**
7 **infrastructure replacement program?**

8 A. Yes. In addition to the 83 miles of bare steel and wrought iron pipe replaced in
9 2024, the Company replaced an additional combined total of 34 miles of first-
10 generation pre-1982 plastic pipe and pre-1971 coated steel. As Company witnesses
11 Scutta and Brumley discuss in their testimonies, at Columbia Statements 14 and 7,
12 respectively, first generation plastic pipe, typically installed between 1970 and 1981
13 in most distribution systems, is more brittle than today’s material composition of
14 plastic pipe and has demonstrated itself to be prone to stress propagation cracking
15 under some circumstances. Likewise, pre-1971 coated steel pipe needs to be
16 prioritized for replacement, as federal standards requiring operators to
17 cathodically protect and maintain all new steel piping installations were not
18 adopted until 1971. Beginning in the 1950s and into the 1960s, coated steel pipe
19 was installed in gas distribution systems as a means of fending off corrosion.
20 However, in those early years the industry lacked standards for cathodic
21 protection and coating material was not as effective as today’s materials, and

1 hence, pre-1971 coated steel pipe has been identified for accelerated replacement.

2 As we move forward, and these facilities continue to age, the Company now
3 includes these facilities in its prioritization of assets to be replaced in accordance
4 with its approved 2023-2027 LTIIP.

5 **Q. How does SMS benefit Columbia's customers?**

6 A. SMS enhances Columbia's risk prioritization and modeling, and strengthens and
7 formalizes our continuous improvement processes, which helps us provide the
8 safest possible service at the best cost to the customer. These enhancements will
9 continue to improve the integration of all pipeline safety initiatives across the
10 Company's organization. Through SMS we are increasing our rigor, and
11 continuously learning and improving so we can identify risks and take actions to
12 keep our employees, contractors, customers and communities safe. SMS uses the
13 following building blocks: (1) culture – as all employees and contractors are
14 empowered to report risks; (2) process safety – layers of protection for safe work
15 with a focus on enhanced consistent standards and processes; and (3) asset
16 management – accountability to effectively evaluate, prioritize, and mitigate
17 identified risks.

18 **III. REVENUE REQUIREMENT**

19 **Q. How did Columbia determine the revenue requirement for this case?**

20 A. As described in the Direct Testimony of Company witness Vassalotti (Columbia
21 Statement No. 4), Columbia reviewed its costs to serve its customers using a FPFTY

1 ending December 31, 2026, pro forma and adjusted for known and measurable
2 changes. Columbia then compared the costs determined for the FPFTY to the
3 revenues at present rates calculated for the FPFTY. This analysis produced a
4 revenue deficiency, from which Columbia calculated the corresponding revenue
5 requirement to make up this deficiency, including a fair rate of return on the
6 investment devoted to serving the public.

7 **Q. Why is the proposed rate increase necessary to address the revenue**
8 **deficiency?**

9 A. Columbia's current rates do not provide the opportunity for the Company to recover
10 its costs to serve its customers, including a fair rate of return on the capital invested
11 to provide distribution service to the public in the FPFTY. The proposed rates have
12 been developed to address this deficiency.

13 **Q. Without the increase requested in this case, what rate of return will**
14 **Columbia experience?**

15 A. Without the increase requested, Columbia's overall rate of return will drop to 6.48%
16 in the FPFTY as shown on Exhibit 102, Schedule 3, Page 3.

17 **Q. What overall rate of return and return on equity does Columbia**
18 **propose in this case?**

19 A. Columbia proposes an overall rate of return of 8.55%. Company witness Rea
20 (Columbia Statement No. 8) demonstrates that Columbia should be granted an
21 opportunity to earn a 11.35% rate of return on common equity.

1 **IV. INTRODUCTION OF WITNESSES**

2 **Q. Please introduce Columbia's witnesses and describe their testimony.**

3 A. Columbia presents the following witnesses:

- 4 • Company witness Michael Girata is Manager of Demand Forecasting for NiSource
5 Corporate Services Company ("NCSC"), providing demand forecasting services for
6 Columbia. In Columbia Statement No. 2, he explains how residential and
7 commercial sales volumes are normalized for weather. The results of the
8 normalization procedure are contained in Company witness Battig's testimony
9 (Columbia Statement No. 3) and Exhibit 3, Schedule 4. Company witness Girata
10 also explains the projection of the future test year and fully projected future test
11 year customer and load growth.
- 12 • Company witness May Battig is a Lead Regulatory Analyst for NCSC. In Columbia
13 Statement No. 3, Company witness Battig supports the Company's requested
14 increase in base rates by providing detailed information on the Company's pro
15 forma operating revenues for the historical test year ("HTY") ending November 30,
16 2024, the future test year ("FTY") ending November 30, 2025, and for the twelve
17 months ending December 31, 2026.
- 18 • Company witness Joseph Vassalotti is a Senior Regulatory Analyst for NCSC. In
19 Columbia Statement No. 4, Company witness Vassalotti presents Columbia's cost of
20 service and quantifies the revenue deficiency based on operating expenses and

1 revenues, as adjusted. Company witness Vassalotti supports Columbia's cost of
2 service O&M expenses.

- 3 • Company witness John J. Spanos is the President of Gannett Fleming Valuation
4 and Rate Consultants, LLC. In Columbia Statement No. 5, Company witness
5 Spanos supports the depreciation study Gannett Fleming prepared for Columbia's
6 gas plant.

- 7 • Company witness Kevin Johnson is a Lead Regulatory Analyst for NCSC. In
8 Company Statement No. 6, he testifies about Columbia's allocated cost of service
9 studies.

- 10 • Company witness Ray Brumley is the Director of Construction Services for
11 Columbia. In Columbia Statement No. 7, Company witness Brumley will discuss
12 Columbia's ongoing replacement activities and provide testimony in support of
13 Columbia's plant additions through the FPFTY.

- 14 • Company witness Vince Rea is Managing Director of Regulatory Finance
15 Associates, LLC, an independent financial and regulatory consulting firm. In
16 Columbia Statement No. 8, Company witness Rea presents detailed testimony and
17 documentation and a recommendation concerning the appropriate cost of common
18 equity and overall rate of return that the Commission should recognize in this case.
19 His recommendation is supported by detailed financial data and an in-depth
20 explanation of the application of the various financial models upon which he relies.

- 1 • Company witness Nicole Paloney is the Director of Rates and Regulatory Affairs for
2 Columbia. In Columbia Statement No. 9, Company witness Paloney provides
3 testimony in support of Columbia's performance quality in compliance with Section
4 523 of the Public Utility Code during 2024 and at the outset of 2025. She also
5 provides support for the Company's proposed Rate Schedule EDDS.
- 6 • Company witness Jennifer Harding is the Vice President of Tax for NCSC. In
7 Columbia Statement No. 10, Company witness Harding supports Columbia's
8 income tax and other tax expense included in the cost of service. She provides
9 detail about both federal and state income tax recovery, and reduction of rate base
10 for deferred income taxes.
- 11 • Company witness Julie Covert is a Lead Regulatory Analyst for NCSC. In Columbia
12 Statement No. 11, she provides detail and support about the methods and
13 assumptions used to develop the HTY, FTY and FPFTY as presented in Exhibits 8
14 and 108.
- 15 • Company witness Ribeka Danhires is Manager of Rates & Regulatory Service for
16 Columbia. In Columbia Statement No. 12, Company witness Danhires explains and
17 supports the tariff changes that the Company seeks to make in this proceeding.
- 18 • Company witness Joe Nunley is a Partner in the Green Energy Economics Group.
19 In Columbia Statement 13, Company witness Nunley will support the renewal and
20 expansion of the Company's Residential Energy Efficiency program and discuss the

1 benefits of energy efficiency to customers. Company witness Nunley will also
2 address the Company's Small Commercial program proposal.

- 3 • Company witness Brian Scutta is the Interim Vice President and General Manager
4 for Columbia. In Columbia Statement No. 14, Company witness Scutta provides an
5 overview of Columbia's distribution system, Columbia's historic operating
6 performance, the initiatives taken to improve its overall safety and compliance
7 efforts and the metrics that are used to track performance and progress, and the
8 planned system enhancements to Columbia's operations. In addition, he provides
9 information regarding Columbia's Distribution Integrity Management Program
10 ("DIMP"), the strategic O&M activities that it has undertaken to improve its system,
11 and the additional O&M activities that Columbia is planning to undertake
12 beginning in 2026.

- 13 • Company witness George Jonda is as Manager of Corporate O&M and
14 Consolidation in the Financial Planning and Analysis ("FP&A") for NCSC. In
15 Columbia Statement No. 15, Company witness Jonda provides testimony in support
16 of the budgeted O&M expenses for NCSC for the FPFTY that are included in
17 Columbia witness Vassalotti's cost of service analysis.

- 18 • Company witness Deborah Davis is the Manager of Universal Servies for Columbia.
19 In Columbia Statement No. 16, Company witness Davis will propose a pilot to
20 address an existing barrier to reenrolling customers in CAP, a pilot to use speech
21 analytics technology to improve outreach to CAP customers and a change to the

1 recovery of costs associated with CARES, specifically LIHEAP and CAP
2 administration.

- 3 • Company witness John Taylor is a Consultant with Atrium Economics. In Columbia
4 Statement No. 17, Company witness Taylor provides support for Columbia's
5 proposed rate design in this case, including fixed cost recovery, WNA and RNA
6 proposals.

- 7 • Company witness Jason Leal is the Lead Financial Planning Analyst for NCSC. In
8 Columbia Statement No. 18, Company witness Leal provides background on the
9 budgeting process for Columbia's Gas Utility Segment departments, which include
10 Field Operations, Construction, Customer Programs, President, and Safety
11 Compliance and Risk Management, and how the Company's budget is determined.

12 **Q. Are you sponsoring any exhibits in this proceeding?**

13 A. Yes. I am sponsoring Exhibit No. 13, Schedule 3, which cross references the
14 standard filing requirements with the corresponding Exhibits and Schedules in this
15 filing for both the historic and future test years. I am also supporting Exhibit 113,
16 Schedule 1, which documents tariff changes resulting from the requested increase.

17 **Q. Does this conclude your Direct Testimony?**

18 A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility
Commission

v.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2025-3053499

DIRECT TESTIMONY OF
MICHAEL E. GIRATA
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

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I. Introduction

Q. Please state your name and business address.

A. My name is Michael E. Girata, and my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

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

A. I am employed by NiSource Corporate Services Company (“NCSC”), a subsidiary of NiSource Inc. (“NiSource”), as Manager of Financial Planning & Analysis.

Q. Please briefly describe your professional experience.

A. After starting my career in data science consulting, I joined NCSC in June 2017, as a Senior Business Analytics Analyst assisting with report building and predictive modeling efforts. In January 2019, I joined our GPS Program Management team as a Project Lead, focusing my efforts on program management and IT support in the form of dashboard development and automation. In February 2020, I joined the Demand Forecasting team as a Lead Analyst supporting forecast development for financial planning, regulatory filings, and peak modeling efforts for our electric business. In August 2021, I joined NCSC’s Corporate Strategy & Risk team as a Project Consultant, helping define NCSC’s electric strategy related to generation and emerging technologies. In June 2022, I rejoined the Demand Forecasting team, where my responsibilities included demand forecasting and revenue planning. My prior title was Manager, Demand Forecasting, and my current title is Manager of Financial Planning & Analysis, where I am responsible for demand forecasting.

Q. Please describe your educational background.

1 A. I graduated from Westminster College with a Bachelor's Degree in Mathematics
2 in December 2014.

3 Q. What are your responsibilities in your current position?

4 A. In my current position as Manager of Financial Planning & Analysis, I am
5 responsible for the development of short-range and long-range forecasts of
6 customers and energy consumption for the natural gas utilities in NiSource's
7 natural gas distribution segment, including Columbia Gas of Pennsylvania, Inc.
8 ("Columbia" or "the Company"). I have the same responsibilities for NiSource's
9 one combination gas-electric utility, along with peak modeling efforts for
10 NiSource's electric segment. I am also responsible for other business-related
11 analyses and forecasts related to revenue planning.

12 Q. Have you previously testified before this or any other regulatory
13 agency?

14 A. Yes, I have testified before the Commission in Columbia's previous rate case
15 (Docket No. R-2024-3046519). I have also testified before the state regulatory
16 commissions in Maryland and Kentucky on behalf of Columbia Gas of Maryland,
17 Inc. and Columbia Gas of Kentucky, Inc., respectively.

18 Q. What test years will you be addressing in this testimony?

19 A. I will be addressing the twelve-month period ending November 30, 2024 as the
20 Historic Test Year ("HTY"), the twelve-month period ending November 30, 2025
21 as the Future Test Year ("FTY"), and the twelve-month period ending December
22 31, 2026 as the Fully Projected Future Test Year ("FPFTY").

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

1 A. I will explain how residential and commercial sales are normalized for weather.
2 The results of the normalization process are contained in Company witness May
3 Battig's testimony (Columbia Statement No. 3) and Exhibit 003, Schedule 04. I
4 will also explain the forecast methodology used to develop forecasted number of
5 customers and usage for the FTY and the FPFTY. The results of the forecast are
6 contained in Exhibit 010, Schedule 02.

7 II. Weather Normalization of Historical Test Year

8 Q. Please explain the weather normalization methodology.

9 A. At a high level, actual sales per customer are separated into base use and
10 temperature-sensitive use per customer for each month of the HTY for the
11 residential and commercial classes. Monthly temperature-sensitive use per
12 customer is adjusted by the ratio of normal to actual heating degree days ("HDD")
13 by month to derive normal temperature-sensitive use per customer by month. The
14 monthly normal temperature-sensitive use per customer is added to the base use
15 per customer to arrive at the normal sales per customer. This value is multiplied
16 by the customer count by month to produce monthly normal sales. All calculations
17 are performed on a billing month basis and use billing month sales, the average
18 number of days in the billing cycle, and billing month HDD.

19 Q. What data sources do you use for your calculations?

20 A. I use the Company's billing records to obtain monthly customer counts and billed
21 sales for the residential and commercial classes for the HTY. I use temperatures
22 from DTN, a weather consulting service which aggregates National Weather
23 Service weather stations relevant to the Company's service territory, to calculate

1 HDD. I rely on temperature data from five weather stations due to the
2 geographical dispersion of Columbia's customers. A weighted average HDD for
3 the Company is calculated by using the percent of residential customers assigned
4 to each station as a weight for that station.

5 Q. How is base usage determined?

6 A. Base usage is the portion of usage that is not dependent on weather, i.e., not
7 temperature-sensitive. I assume that there is no temperature sensitive usage in
8 the summer months of July and August, and therefore, all usage in July and August
9 is base use and is not affected by the weather normalization process. In addition,
10 the total use per customer per day (Total Use/Customer/Day) for July and August
11 is all base use. If total use per customer per day in September is less than July or
12 August, then I also assume September has no temperature sensitive usage (i.e.,
13 September is also assumed to be a base use-only month and not affected by the
14 weather normalization process). The base use per customer per day used to
15 weather normalize the remaining months of the HTY is calculated by averaging the
16 two lowest observed use per customer per day values from the months of July
17 through September.

18 Q. How are monthly sales in the remaining months weather normalized?

19 A. The base use per customer per day is multiplied by the number of days ((base
20 use/customer/day)*days in billing cycle) to produce monthly base use per
21 customer. Temperature-sensitive use per customer equals the total use per
22 customer minus the base use per customer. The temperature-sensitive use per
23 customer is normalized for weather by multiplying it by a ratio of normal HDD to

1 actual HDD. Normal use per customer is calculated by adding the base use per
2 customer to the normal temperature-sensitive use per customer. Total monthly
3 normalized usage is generated by multiplying monthly normal use per customer
4 by the monthly customer count. This calculation for the HTY is prepared separately
5 for residential and commercial customers, and the results are presented in Exhibit
6 010, Schedule 08.

7 Q. Has the methodology for normalizing weather changed from
8 **Columbia's last rate filing?**

9 A. No, the methodology has not changed since Columbia's last rate filing. However,
10 the historical average HDD have been updated to include the most recent 20-year
11 history (i.e., 20 years ended December 31, 2024). The previous base rate case filing
12 defined normal weather as the 20-year average ending in 2023. In all other
13 respects, the weather normalization process is the same.

14 Q. Why is Columbia using a 20-year average HDD in the weather
15 normalization process?

16 A. The Company continues to use the 20-year average HDD in the weather
17 normalization process because it is consistent with the Company's approach since
18 2008. In addition, an analysis of weather data demonstrates that a rolling 20-year
19 average is a superior predictor of one-year-ahead HDD and five-year ahead HDD
20 than the 30-year average HDD, and the 20-year average HDD is a more dynamic
21 measure than the 30-year average HDD, as discussed in more detail below.

1 Q. Please explain your analysis that demonstrates that the 20-year
2 average HDD is a better predictor of one-year-ahead and five-year
3 ahead HDD than the 30-year average HDD.

4 A. Table 1, below, compares the actual HDD experienced each year from 1987 through
5 2024 with the historical average HDD calculated using either the prior 20-years or
6 the prior 30-years. The absolute error is calculated as the absolute value of the
7 difference between the actual HDD and either the 20-year or 30-year average.
8 Table 1 demonstrates that the 20-year average HDD has a lower absolute error
9 than the 30-year average HDD in 63% of the most recent 38 years. Table 1 also
10 illustrates that the 20-year average HDD has a lower mean absolute error when
11 predicting the one-year-ahead HDD, as compared to the 30-year average HDD
12 when considering the most recent 38-year period.

13 In Table 2, the 20-year and 30-year average HDD are used to predict annual
14 HDD for each five-year period for the five years ended 1991 through the five years
15 ended 2024. As measured by the smallest sum of absolute differences over the
16 five-year period, the 20-year average HDD outperforms the 30-year average HDD
17 in 97% or 33 out of the 34 periods. When considering the most recent ten periods,
18 the 20-year average HDD outperforms the 30-year average HDD in 90% or 9 out
19 of the 10 periods.

Table 1
Weather Averages as Predictors
Moving Averages used to Predict Following Year
Columbia Gas of Pennsylvania

	Annual Heating Degree Days			1-Year Absolute Error		Better 1-Year Predictor	
	Actual	20-yr Average	30-yr Average	20-yr Average	30-yr Average	20-yr Average	30-yr Average
1986		5,826	5,852				
1987	5,449	5,806	5,850	377	403	x	
1988	5,991	5,801	5,843	185	141		x
1989	5,992	5,799	5,855	191	149		x
1990	4,742	5,745	5,811	1,057	1,113	x	
1991	4,996	5,713	5,781	749	815	x	
1992	5,591	5,697	5,763	122	190	x	
1993	5,589	5,710	5,741	108	174	x	
1994	5,582	5,718	5,740	128	159	x	
1995	5,619	5,723	5,734	99	121	x	
1996	5,855	5,707	5,731	132	121		x
1997	5,681	5,693	5,725	26	50	x	
1998	4,582	5,614	5,675	1,111	1,143	x	
1999	5,195	5,578	5,647	419	480	x	
2000	5,633	5,549	5,641	55	14		x
2001	5,190	5,501	5,626	359	451	x	
2002	5,340	5,482	5,607	161	286	x	
2003	5,824	5,479	5,623	343	217		x
2004	5,420	5,462	5,623	59	203	x	
2005	5,589	5,466	5,626	127	34		x
2006	4,987	5,442	5,586	479	639	x	
2007	5,389	5,439	5,567	53	197	x	
2008	5,590	5,419	5,548	151	23		x
2009	5,522	5,396	5,535	103	26		x
2010	5,468	5,432	5,510	72	67		x
2011	5,224	5,444	5,479	208	286	x	
2012	4,744	5,401	5,446	700	735	x	
2013	5,521	5,398	5,434	120	75		x
2014	5,916	5,414	5,440	518	482		x
2015	5,310	5,399	5,433	104	130	x	
2016	4,972	5,355	5,417	427	461	x	
2017	4,829	5,312	5,396	526	588	x	
2018	5,495	5,358	5,380	183	99		x
2019	5,198	5,358	5,353	160	182	x	
2020	4,915	5,322	5,359	443	438		x
2021	4,874	5,306	5,355	448	485	x	
2022	5,351	5,307	5,347	45	4		x
2023	4,422	5,237	5,308	885	925	x	
2024	4,315	5,182	5,266	922	993	x	
				Mean Absolute Error		Frequency of Lowest Error	
	1987-2024			325	345	24	14
	2015-2024			414	430	7	3
				Relative Frequency			
	1987-2024			63%	37%		
	2015-2024			70%	30%		

Table 2
Weather Averages as Predictors
Moving Averages used to Predict the Following Five Years
Columbia Gas of Pennsylvania

	Annual Heating Degree Days			5-Year Absolute Error		Better 5-Year Predictor	
	Actual	20-yr Average	30-yr Average	20-yr Average	30-yr Average	20-yr Average	30-yr Average
1986		5,826	5,852				
1987	5,449	5,806	5,850				
1988	5,991	5,801	5,843				
1989	5,992	5,799	5,855				
1990	4,742	5,745	5,811				
1991	4,996	5,713	5,781	2,622	2,648	x	
1992	5,591	5,697	5,763	2,460	2,504	x	
1993	5,589	5,710	5,741	2,477	2,602	x	
1994	5,582	5,718	5,740	2,495	2,777	x	
1995	5,619	5,723	5,734	1,350	1,680	x	
1996	5,855	5,707	5,731	613	818	x	
1997	5,681	5,693	5,725	474	672	x	
1998	4,582	5,614	5,675	1,521	1,615	x	
1999	5,195	5,578	5,647	1,931	1,997	x	
2000	5,633	5,549	5,641	1,933	1,965	x	
2001	5,190	5,501	5,626	2,254	2,374	x	
2002	5,340	5,482	5,607	2,523	2,687	x	
2003	5,824	5,479	5,623	1,346	1,491	x	
2004	5,420	5,462	5,623	1,085	1,182	x	
2005	5,589	5,466	5,626	1,012	1,208	x	
2006	4,987	5,442	5,586	1,167	1,366	x	
2007	5,389	5,439	5,567	1,099	1,259	x	
2008	5,590	5,419	5,548	862	1,142	x	
2009	5,522	5,396	5,535	863	1,039	x	
2010	5,468	5,432	5,510	738	1,173	x	
2011	5,224	5,444	5,479	525	745	x	
2012	4,744	5,401	5,446	1,173	1,332	x	
2013	5,521	5,398	5,434	1,124	1,260	x	
2014	5,916	5,414	5,440	1,541	1,564	x	
2015	5,310	5,399	5,433	1,591	1,669	x	
2016	4,972	5,355	5,417	1,855	1,890	x	
2017	4,829	5,312	5,396	1,727	1,772	x	
2018	5,495	5,358	5,380	1,698	1,734	x	
2019	5,198	5,358	5,353	1,429	1,505	x	
2020	4,915	5,322	5,359	1,778	1,879	x	
2021	4,874	5,306	5,355	1,744	1,929	x	
2022	5,351	5,307	5,347	1,171	1,345	x	
2023	4,422	5,237	5,308	2,030	2,138	x	
2024	4,315	5,182	5,266	2,913	2,889		x

	Mean Absolute Error		Frequency of Lowest Error	
1991-2024	1,562	1,702	33	1
2015-2024	1,794	1,875	9	1

	Relative Frequency	
1991-2024	97%	3%
2015-2024	90%	10%

Q. Please explain your analysis that demonstrates that the 20-year average HDD is more dynamic than the 30-year average HDD.

A. Table 3 demonstrates that the average annual change for the 20-year average HDD is 0.4%, while the average annual change for the 30-year average is 0.3% HDD. The 20-year normal HDD is a more dynamic measure that is better able to react more quickly to weather changes because it replaces 5% of the data each year rather than the 3% that is replaced with the 30-year average.

Table 3 Weather Averages Annual Change in Averages 1987-2024 Absolute Values Columbia Gas of Pennsylvania			
	20-yr Average	30-yr Average	Annual HDD
Average	0.4%	0.3%	6.9%
Maximum	1.4%	0.9%	20.9%

III. Demand Forecast Methodology for Future Test Year and Fully Projected Future Test Year

A. Demand Forecast Methodology Overview

Q. Please explain the methodology employed for developing the forecasted number of customers and volume for the FTY and FPFTY.

A. Total residential customers and volume for both the FTY and FPFTY are forecasted using econometric models. Total commercial customers and volume for both the FTY and FPFTY are forecasted using a combination of econometric models and based on knowledge gained through relationships with large commercial customers. Total industrial volume for both the FTY and FPFTY are forecasted based on knowledge gained through relationships with large industrial customers. Total residential, total commercial, and total industrial forecasts are subsequently

split into sales, choice, and GTS customers and volumes, as appropriate, using historical data.

Q. What data sources do you use to develop the econometric models for the residential and commercial classes?

A. I use the Company's billing records through November 2024 to obtain historical monthly customer counts and billed usage for the residential and commercial customer classes. Historical billed usage is divided by historical customer counts to produce monthly historical use per customer data for residential and commercial customers. The historical customer counts and use per customer are used as the dependent variables in the residential customer, residential use per customer, commercial customer, and commercial use per customer econometric models.

Several sources are used to obtain data for the independent variables included in the econometric models. Historical and forecast average efficiency data is provided by Itron Inc., a national utility consulting firm. Historical and forecast values for economic and demographic variables (e.g., number of households and gross county product) and deflator data are from IHS Markit (a subsidiary of S&P Global), a data consultant. Historical weather data (HDD) is provided by DTN, a weather consulting service, and the same 20-year average HDD described in the weather normalization process above is used as the weather during forecast period.

B. Residential Forecast

Q. Please describe the residential customer forecast methodology.

1 A. The residential customer forecast is developed using a monthly econometric model
2 that incorporates the number of households and monthly variables for shaping.

3 Q. Please describe the residential use per customer forecast methodology.

4 A. The residential use per customer forecast is developed using a monthly econometric
5 model that incorporates weather in the form of HDD, energy intensity, and monthly
6 variables for additional shaping.

7 Q. How is the forecast of monthly residential volume determined?

8 A. Monthly residential customer counts are multiplied by monthly residential use per
9 customer to produce monthly residential volume.

10 Q. How are the total residential customers and usage split into residential
11 sales and residential CHOICE?

12 A. Residential CHOICE customer counts are based on extrapolating the recent
13 declining trend in residential CHOICE customers. Residential sales customer
14 counts are determined by subtracting residential CHOICE customer count from
15 the total residential customer count.

16 Use per customer for residential CHOICE customers has been higher than
17 use per customer for residential sales customers in recent years. Forecasted use
18 per customer for residential CHOICE customers is determined by applying the
19 historical monthly ratio of residential CHOICE use per customer to total
20 residential use per customer. Forecasted residential CHOICE usage is determined
21 by multiplying residential CHOICE customers by residential CHOICE use per
22 customer. Residential sales usage is determined by subtracting residential
23 CHOICE usage from the total residential usage.

1 Q. **Is the impact of the Company's residential energy efficiency program**
2 incorporated into the residential demand forecast?

3 A. Columbia had a new energy efficiency program go into effect in August 2023. Since
4 the DSM savings are in a relatively small portion of historical volumes,
5 adjustments were made to the historical data to reflect what total demand would
6 look like had the program not been implemented. The usage per customer forecast
7 was built on this adjusted data.

8 The resulting forecast was a view of residential usage per customer with no
9 energy efficiency program impacts. This usage per customer forecast was
10 multiplied by the customer count forecast to create the total volumetric forecast.
11 Finally, projected savings from the energy efficiency program were applied to the
12 volumetric forecast to create the final volumetric forecast for the residential
13 customer class.

14 C. Commercial Forecast

15
16 Q. Please describe the commercial customer forecast methodology.

17 A. The small commercial customer forecast is developed using a monthly econometric
18 model that incorporates real income per capita and monthly variables for shaping.
19 The large commercial customer forecast is developed using currently active large
20 commercial customers, and making adjustments for upcoming customer adds and
21 customer closures.

22 Q. Please describe the commercial use per customer forecast
23 methodology.

24 A. The small commercial use per customer forecast is developed using a monthly

1 econometric model that incorporates weather in the form of HDD, and monthly
2 variables for additional shaping. The large commercial use per customer forecast is
3 developed by the Large Customer Relations group by incorporating information
4 generated through individual customer interviews.

5 Q. How is the forecast of monthly commercial volume determined?

6 A. Monthly small commercial customer counts are multiplied by monthly small
7 commercial use per customer to produce monthly small commercial volume. This
8 small commercial volume is then added to the large commercial volume forecast
9 from Large Customer Relations to arrive at total commercial volume.

10 Q. How are the total commercial customers and volumes split into
11 commercial sales, commercial CHOICE, and commercial GTS?

12 A. Commercial GTS and commercial CHOICE customers are forecasted to remain at
13 recent historical customer levels. Commercial sales customers are the customers
14 remaining when commercial GTS and commercial CHOICE customers are
15 subtracted from the total commercial customer forecast. Total commercial usage
16 is allocated to sales, GTS and CHOICE-based proportions experienced in the most
17 recent twelve months.

18 D. Industrial Forecast
19

20 Q. Please describe the industrial forecast methodology.

21 A. The industrial forecast is provided by the Large Customer Relations group by
22 incorporating information generated through individual customer interviews. Since
23 the Large Customer Relations group covers over 90% of the total industrial volumes,

1 it is assumed that the remaining industrial volume grows at the same rate as those
2 forecasted by the Large Customer Relations group.

3 Q. How is the total industrial usage split into industrial sales and
4 industrial GTS?

5 A. Total industrial usage is allocated to sales and GTS based upon monthly
6 proportions experienced in the most recent 24 months.

7 Q. Does this conclude your prepared Direct Testimony?

8 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

v.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2025-3053499

DIRECT TESTIMONY OF
MAY BATTIG
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

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I. Introduction

Q. Please state your name and business address.

A. My name is May Battig. My business address is 290 West Nationwide Boulevard, Columbus, Ohio, 43215.

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

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Lead Regulatory Analyst in the Regulatory Studies Department at NCSC.

Q. Please briefly describe your professional experience.

A. I have over 20 years of experience working in various financial planning and regulatory functions primarily supporting NiSource gas distribution companies. In May 2001, I joined NCSC as a Financial Analyst in the Financial Planning Department for Columbia Gas Distribution Companies. From 2001 – 2006, I held several positions of increasing responsibility and worked specifically on the budgets for Bay State Gas Company dba Columbia Gas of Massachusetts ("CMA") and Columbia Gas of Ohio ("COH"). In mid-2006, I accepted a position as a Senior Regulatory Analyst in NCSC's Regulatory Strategy and Support Department. I became a Lead Regulatory Analyst in 2009. In mid-2009, I returned to Financial Planning as a Lead Financial Analyst working on budgets for COH. From 2013 to present, I rejoined Regulatory Strategy and Support as a Lead Regulatory Analyst supporting various NiSource companies.

Q. Please describe your educational background.

1 A. I graduated from The Ohio State University in 1994 with a Bachelor of Science degree
2 in Business Administration, majoring in Finance and Economics.

3 **Q. What are your responsibilities in your current position?**

4 A. My primary responsibilities as a Lead Regulatory Analyst include providing support
5 for regulatory filings and rate cases for NiSource gas distribution companies,
6 including, Columbia Gas of Pennsylvania, Inc. (“Columbia” or “the Company”),
7 Columbia Gas of Maryland, Inc., Columbia Gas of Kentucky, Inc., Columbia Gas of
8 Virginia, Inc., and COH.

9 **Q. Have you previously testified before this or any other regulatory agency?**

10 A. I have presented direct testimony for Columbia before the Pennsylvania Public Utility
11 Commission in Case No. R-2024-3046519. Also, I have submitted direct testimony for
12 Columbia Gas of Maryland before the Public Service Commission of Maryland in Case
13 Nos. 9417, 9447, 9609, and 9754.

14 **Q. What was the nature of the testimony you provided in those**
15 **proceedings?**

16 A. In connection with those rate case proceedings, I prepared and submitted testimony
17 on revenue and Cash Working Capital (“CWC”)/Lead Lag Study.

18 **II. Purpose and Summary of Testimony**

19 **Q. Please state the purpose of your prepared direct testimony in this**
20 **proceeding.**

21 A. I am sponsoring and describing Exhibits 3 and 103 (Operating Revenues). I am also

sponsoring the following exhibits:

<u>Exhibit No.</u>
Exhibit 002, Schedule 07, (16), Page 01
Exhibit 003, Schedules 01 through 10, (02) (03) (04), Pages 01-05
Exhibit 010, Schedule 03, (22), Page 01
Exhibit 010, Schedule 04, (38), Page 01
Exhibit 010, Schedule 07, (03) (14), Page 01
Exhibit 012, Schedule 01, (05), Page 01
Exhibit 012, Schedule 02 (18), Pages 01-02
Exhibit 012, Schedule 03, (23), Page 01
Exhibit 012, Schedule 04, (24) (26) (30) (36), Page 01
Exhibit 012, Schedule 04, (25), Page 01
Exhibit 012, Schedule 05, (31), Page 01
Exhibit 012, Schedule 06, (11), Page 01
Exhibit 012, Schedule 07, Pages 01-02
Exhibit 012, Schedule 08, Page 01
Exhibit 016, (7), Pages 01-05
Exhibit 017, (01) (28), Pages 01-07
Exhibit 103, Schedules 01 through 7, (02) (03) (04), Pages 01-15
Exhibit 110, Schedule 03, (22), Page 01
Exhibit 110, Schedule 04, (38) (39), Page 01
Exhibit 110, Schedule 07, (03) (14), Page 01
Exhibit 112, Schedule 01 (05) Page 01
Exhibit 112, Schedule 02, (18) (23) thru (26) (30) (31) (36) (11), Pages 01-04
Exhibit 112, Schedule 03, Pages 01-03
Exhibit 112, Schedule 04, Page 01
Exhibit 116, (07), Page 01
Exhibit 117, (01) (28), Pages 01-02

Q. Are you sponsoring any additional exhibits?

A. Yes. Attached to my testimony are two additional exhibits that support the Company's revenue proposal. Each exhibit, identified below, will be addressed later in my testimony.

<u>Exhibit No.</u>	<u>Description</u>
Exhibit MLB-1	Calculation of the Merchant Function Charge
Exhibit MLB-2	Annualization of Forfeited Discounts (Account 487)

III. Operating Revenues

A. Exhibit 3

Q. Please explain the process that was undertaken to produce the number of bills used to price revenue in this case.

A. The following calculations are made to determine the number of bills found in Exhibit 3, Schedule 2, for the Historic Test Year (“HTY”). Active customer counts for each month of the HTY are accumulated by rate schedule and shown in Column 1 of Exhibit 3, Schedule 2. The bills are accumulated based on which rate schedule the customer is on at the end of the HTY. Adjustments were made in Exhibit 3, Schedule 2, Column 2 to reflect discontinued or added services for Large Commercial and Industrial customers. Incremental residential and commercial customers that were added or discontinued during the HTY are shown in Columns 3 and 4, respectively, for a full year impact. The corresponding backup for customer additions and attrition for the HTY can be found in Exhibit 3, Schedule 5, Pages 1 – 7. Finally, an adjustment is made to the number of bills for final billed customers, because a Customer Charge is billed to customers who receive a final

1 bill even though they are not included as an active customer. These customers are
2 not classified as active in the Company's billing systems during the HTY, so the
3 final bills must be added to active bills to price revenue in this case. Bills in Exhibit
4 3, Schedule 2, Column 7 are used for pricing in Exhibit 3, Schedule 1 (pro forma
5 revenue at current rates) and Exhibit 3, Schedule 10 (pro forma revenue at
6 proposed rates).

7 **Q. Please explain the development of the adjusted volumes in Dekatherms**
8 **("Dth") for the HTY.**

9 A. Physical flow volumes were summarized by rate schedule in Exhibit 3, Schedule 3 on
10 a customer-by-customer, and month-by-month basis. The volumes, as shown in
11 Column 1, were accumulated based on the rate schedule the customer was on at
12 November 30, 2024. The Weather Normalization Adjustment ("WNA") in Exhibit 3,
13 Schedule 3, Column 2 represents the change to physical flow volumes due to the use
14 of a 20-year weather definition normalization. Adjustments were made in Exhibit 3,
15 Schedule 3, Column 3 to reflect discontinued or added services for Large Commercial
16 and Industrial customers. Incremental residential and commercial customers that
17 were added or discontinued during the HTY are shown in Columns 4 and 5,
18 respectively, for a full year impact. The corresponding support for customer
19 additions and attrition for the HTY can be found in Exhibit 3, Schedule 5, Pages 1 –
20 7.

21 **Q. Please explain why physical flow volumes were used instead of invoiced**

volumes as the basis for calculating operating revenues.

A. Physical flow volumes were used instead of invoiced volumes because they represent volumes that flowed during the HTY. Invoiced volumes may include adjustments made for prior billing periods that are outside of the HTY. Therefore, physical flow volumes were used to eliminate out of period adjustments.

Q. How is the 20-year weather normalization definition utilized in Exhibit 3, Schedule 4?

A. Company witness Girata (Columbia Statement No. 2) provided the total normalized volumes by month for residential and commercial customers. The total normalized volumes were allocated based on the customers' actual physical flow volumes and by their class. Then they were accumulated by rate schedule by rate block, if applicable, as shown in Exhibit 3, Schedule 4, Column 2. The weather adjustment in Column 3 is calculated by subtracting actual physical flow Dth in Column 1 from the normalized Dth in Column 2. The revenue impact as shown in Column 5 is determined by multiplying the Dth in Column 3 by the current base rates in Column 4.

Q. Please explain Schedules 6 through 9 of Exhibit 3.

A. Schedules 6 and 7 eliminate certain per book amounts (off system sales revenues, unbilled revenues and unbilled gas costs) that are not relevant to a pro forma calculation of revenues and expenses. Schedules 8 and 9 show the calculated split of per books gas cost, Gas Procurement Charge ("GPC"), Rider Universal Service Plan ("USP"), Merchant Function Charge ("MFC"), Rider Customer Choice ("CC"), and

1 Rider Energy Efficiency (“EE”) by customer class used in reconciling per books
2 revenue to annualized revenue in Exhibit 3, Page 9.

3 **Q. How was pro forma revenue at current rates calculated?**

4 A. As shown in Exhibit 3, Schedule 1, adjusted test year bills from Schedule 2 are
5 shown in Column 1 and adjusted test year Dth from Schedule 3 are shown in
6 Column 2. Current rates are shown in Column 3. Revenue is calculated in Column
7 4 by multiplying the Customer Charge by number of bills and volumetric rates by
8 volumes. An average rate per Dth is calculated in Column 5 by dividing Column 4
9 by Column 2. Pro forma revenue at current rates was calculated using the
10 Purchased Gas Cost (“PGC”) rate and Rider USP rate as of January 1, 2025, which
11 is the most recent available at the time the schedules were developed. The MFC
12 rate (please refer to Exhibit MLB–1, attached to this testimony) was updated to
13 reflect the January 1, 2025 PGC rate and the proposed residential and non-
14 residential uncollectible expense ratio as calculated by Company witness Vassalotti
15 and shown in Exhibit No. 4, Schedule 2, Page 27, Lines 7 and 14. The State Tax
16 Adjustment Surcharge (“STAS”) is reflected at 0% on Exhibit 3, Schedule 1.

17 **Q. Please explain the adjustment to Forfeited Discounts (Account 487) in**
18 **Exhibit 3 Page 8.**

19 A. Exhibit MLB-2, attached to this testimony, compares Account 487 revenue to total
20 billed revenue for the three years ending November 2022, November 2023 and
21 November 2024, and calculates a three-year average. This three-year period was

1 selected to match the same basis used by the Company in this rate case to determine
2 an average net write-off rate used for annualization of uncollectible expense. As with
3 net write-offs, Forfeited Discounts historically produce a reasonably predictable
4 percentage of billed revenue over time. A three-year average is used to account for
5 the percentage differences caused primarily by changes in gas cost recovery revenue.

6 The historic three-year average percentage of billed revenue is applied to
7 annualized HTY revenue, resulting in annualized historic test year Forfeited
8 Discounts shown on Exhibit MLB-2, page 1. The historic three-year average
9 percentage of billed revenue is applied to annualized FTY revenue and annualized
10 FPFTY revenue (Exhibit 103), resulting in annualized Forfeited Discounts revenue
11 for those test years shown on Exhibit MLB-2, pages 2 and 3 respectively.

12 **Q. Please explain Exhibit 3 Schedule 10.**

13 A. This schedule calculates pro forma revenues at proposed rates for the HTY
14 reflecting the rate design as shown on Exhibit 103, Schedule 8.

15 **Q. Please explain Pages 6 - 8 of Exhibit 3.**

16 A. The summary shows, by rate schedule by customer class, pro forma test year bills
17 (Column 1), Volumes (Dth) (Column 2), Revenue at Current Rates (Column 3),
18 proposed adjustment (Column 4), and Revenue at Proposed Rates (Column 5).
19 The summary serves as a comparison of revenue at current and proposed rates.

20 **Q. Please explain the “Dth and Revenue Summary at Current Rates” on**
21 **Page 9 of Exhibit 3.**

1 A. This page summarizes revenue for the HTY by customer class and is the
2 reconciliation of per books revenue to annualized revenue as calculated in Exhibit
3 3, Schedule 1. Exhibit 3, Page 9, Column 1 reflects the per books revenue as of
4 November 30, 2024. Columns 2 through 7 show the calculated split of per books
5 gas cost, Rider USP, GPC, MFC, CC, and EE by customer class calculated on Exhibit
6 3, Schedules 8 and 9. The weather normalization adjustment calculated on Exhibit
7 3, Schedule 4 is shown in Exhibit 3, Page 9, Column 10. Column 11 reflects pricing
8 out the test year billing determinants (bills and volumes) at the most current base
9 rates. Column 12 is the pro forma Delivery Service revenue at current rates
10 calculated on Exhibit 3, Schedule 1.

11 **Q. Please explain the “Dth and Revenue Summary at Current Rates” on**
12 **Page 10 of Exhibit 3.**

13 A. This page summarizes annualized total revenue at current rates as calculated on
14 Exhibit 3 Schedule 1. Column 1 shows pro forma base revenue at current rates.
15 Column 2 shows a summary of gas costs at current rates in effect as of January 1,
16 2025. Column 3 shows a summary of Rider USP at current rates in effect as of
17 January 1, 2025. Column 4 shows a summary of the Gas Procurement Charge.
18 Column 5 shows a summary of the MFC. Columns 6 and 7 show a summary of
19 Rider CC and EE respectively. Detailed calculations by rate schedule for Columns
20 1 through 7 are shown in Exhibit 3, Schedule 1. Column 8 shows total revenue at
21 current rates.

B. Exhibit 103

Q. Please describe the projection of bills for the FTY and FPFTY.

A. Forecasted active customer counts are first determined on a total company basis by customer class by type of service (sales/CHOICE transportation/non-CHOICE transportation) by month in the Company's forecast model supported by Company witness Girata on Exhibit 10, Schedule 2. The customer counts are then spread for each month of the FTY and the FPFTY, based on the HTY experience, by rate schedule, by customer class, and by type of service for Residential and Small Commercial sales and CHOICE customers. The bills are accumulated based on which rate schedule the customer is on at the end of the HTY and the results are shown in Exhibit 103, Schedule 2, Column 1.

Adjustments resulting from Large Commercial or Industrial customers that are expected either to discontinue or to add service during the FTY and FPFTY are shown by customer in Exhibit 103, Schedule 4, Pages 16 and 18 respectively, and summarized in Exhibit 103, Schedule 2, Column 2. New construction customers who are expected to begin service during the FTY and FPFTY are shown on Exhibit 103, Schedule 4, Pages 1 and 7, respectively and summarized on Exhibit 103, Schedule 2, Column 3. Customer attrition, which is expected to occur during the FTY and FPFTY, is shown on Exhibit 103, Schedule 4, Pages 3 and 9, respectively, and summarized on Exhibit 103, Schedule 2, Column 4. Column 5 of Exhibit 103, Schedule 2, reflects the shifts between rate schedules that occurred during the test

1 year. The Company considers the HTY final bill count to be representative of what
2 can be expected during the FTY and FPFTY. Therefore, the HTY final bill count
3 was added to the forecasted active bills to price revenue in this case. Final bill
4 counts are shown in Exhibit 103, Schedule 2, Column 6. FTY adjusted number of
5 bills in Exhibit 103, Schedule 2, Column 7 is the sum of Columns 1 through 6. Bills
6 in Column 7 are used for pricing in Exhibit 103, Schedule 1 (pro forma revenue at
7 current rates) and Exhibit 103, Schedule 7 (pro forma revenue at proposed rates)
8 for both the FTY and the FPFTY.

9 **Q. Please explain the process used to develop FTY and FPFTY Dth.**

10 A. Forecasted adjusted Dth for both the FTY and the FPFTY are shown in Exhibit 103,
11 Schedule 3, Column 6 and are the sum of: (a) forecasted Dth in Exhibit 103,
12 Schedule 3, Column 1; (b) Large Commercial and Industrial adjustments in Exhibit
13 103, Schedule 3, Column 2; (c) new construction consumption in Exhibit 103,
14 Schedule 3, Column 3; (d) attrition consumption in Exhibit 103, Schedule 3,
15 Column 4; and (e) rate schedule transfers in Exhibit 103, Schedule 3, Column 5.
16 Volumes in Exhibit 103, Schedule 3, Column 6 are used for pricing in Exhibit 103,
17 Schedule 1 (pro-forma revenue at current rates) and Exhibit 103, Schedule 7 (pro-
18 forma revenue at proposed rates) for both the FTY and FPFTY.

19 Forecasted Dth are first determined by customer class, by type of service
20 (sales/CHOICE transportation/non-CHOICE transportation), by month in the
21 Company's forecast model supported by Company witness Girata in Exhibit 10,

1 Schedule 2. These Dth are spread for each month of the FTY and FPFTY based on
2 the HTY by rate schedule, by customer class, and by type of service for Residential
3 Sales and CHOICE customers. The spread for Commercial and Industrial Sales
4 and CHOICE transportation customers and all non-CHOICE transportation
5 customers is performed down to the individual customer level. The Dth are
6 accumulated based on which rate schedule the customer is on at the end of the
7 HTY and shown in Column 1 of Exhibit 103, Schedule 3.

8 Adjusted Dth in Exhibit 103, Schedule 3, Column 6 are the sum of Columns
9 1 through 5 for both the FTY and FPFTY. Adjustments resulting from Large
10 Commercial and Industrial customers either discontinuing or adding service
11 during the FTY and FPFTY are shown by customer in Exhibit 103, Schedule 4,
12 Pages 16 and 18, respectively, and summarized in Exhibit 103, Schedule 3, Column
13 2 for reasons I explained previously, with respect to customer bills. Consumption
14 calculated for new construction customers who are expected to begin service
15 during the FTY is shown on Exhibit 103, Schedule 4, Pages 10 and 11 and Pages 14
16 and 15 for the FPFTY. The Dth attributable to new customers are summarized on
17 Exhibit 103, Schedule 4, Page 2, Column 1 and are shown on Exhibit 103, Schedule
18 3, Column 3. Customer attrition, which is expected to occur during the FTY and
19 FPFTY is calculated on Exhibit 103, Schedule 4, Pages 3 and 9, respectively, and is
20 shown on Exhibit 103, Schedule 3, Column 4.

21 **Q. Please explain Exhibit 103, Schedule 7.**

1 A. This schedule calculates pro forma revenues at proposed rates for the FTY and
2 FPFTY, respectively, reflecting the rate design as shown on Exhibit 103, Schedule
3 8, sponsored by Company witness Johnson.

4 **Q. Please explain Pages 6 - 9 of Exhibit 103.**

5 A. The summary shows, by rate schedule by customer class, pro forma test year bills
6 (Column 1), Consumption (Dth) (Column 2), Revenue at Current Rates (Column
7 3), proposed adjustment (Column 4), and Revenue at Proposed Rates (Column 5).
8 The summary serves as a comparison of revenue at current and proposed rates.

9 **Q. Please explain the “Dth and Revenue Summary at Current Rates” on**
10 **Pages 10 through 15 of Exhibit 103.**

11 A. These pages summarize annualized total revenue at current rates as calculated on
12 Exhibit 103, Schedule 7. Exhibit 103 includes annualized total revenue for both the
13 FTY and FPFTY.

14 **Q. Please summarize the drivers that make up the difference in revenue**
15 **in Exhibit 103 between the FTY and the FPFTY.**

16 A. The difference between the revenue in the FTY and the FPFTY year is driven by
17 changes in customer growth, attrition, changes in use per customer, expected
18 changes in customer counts, and usage for large customers based upon a customer-
19 by-customer review. See Company witness Girata’s testimony for an explanation
20 of the forecast models.

1 **Q. Are there any requirements from the previous case pertaining to**
2 **revenues to be address in this rate case proceeding?**

3 A. Yes. Pursuant to Paragraph 30 of the approved Partial Settlement in the Company's
4 prior rate case, at Docket No. R-2024-3046519, Columbia is required to prepare in
5 its next base rate proceeding, a comparison of its actual revenue for the twelve
6 months ended December 31, 2025. This comparison will be provided when the
7 information becomes available.

8 **Q. Does this conclude your prepared Direct Testimony?**

9 A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Calculation of Merchant Function Charge Utilized in Exhibit No. 3 and Exhibit No. 103
Calculated Using Gas Costs as of January 1, 2025

Exhibit MLB-1
Page 1 of 1

<u>Line No.</u>	<u>Description</u>	<u>Reference</u>	<u>Rate</u> \$
1	PGCC Rate	Exhibit 1-A, Schedule 1, Page 1, Col. 3, Line 5 (1/01/2025 Quarterly GCR Filing)	<u>2.3646</u>
2	Total Commodity Cost of Gas		2.3646 per Dth
3	Residential Uncollectible Expense Ratio ¹	Exhibit No. 4, Schedule No. 2, Page 25, Line 7	0.0157578
4	Non-Residential Uncollectible Expense Ratio ¹	Exhibit No. 4, Schedule No. 2, Page 25, Line 14	0.0041341
5	Merchant Function Charge - Residential Sales Service	(Line 4 x Line 5)	0.0373 per Dth
6	Merchant Function Charge - Small General Sales Service	(Line 4 x Line 6)	0.0098 per Dth

¹ Per Order in Docket No. R-2012-2321748

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending November 30, 2024

Exhibit MLB-2
Page 1 of 3

Line No.	12 Mos <u>November 2022</u>	12 Mos <u>November 2023</u>	12 Mos <u>November 2024</u>	Total 3 Year <u>Average</u>
1 Per Books Acct 487	\$ 1,599,988	\$ 1,897,169	\$ 1,511,996	\$ 5,009,153
2 Per Books Billed Revenue	<u>\$ 825,062,491</u>	<u>\$ 860,472,954</u>	<u>\$ 736,933,555</u>	<u>\$ 2,422,469,001</u>
3 Forfeited Discounts as a % of Revenue (Line 1 / Line 2)	0.1939%	0.2205%	0.2052%	0.2068%
4 Historic Test Year Sales Revenue (Ex. 3, Page 10, Line 6)				\$ 706,617,063
5 Historic Test Year Revenue -Transportation Revenue (Ex. 3, Page 10, Line 9)				\$ 202,365,763
6 Total Sales and Transportation Revenue (Line 4 + Line 5)				<u>\$ 908,982,826</u>
7 3 Year Average				0.2068%
8 Annualized Forfeited Discounts (Line 7 * Line 6)				<u>\$ 1,879,776</u>
9 Historic Test Year Acct 487 (Ex. 3, Page 9)				\$ 1,511,996
10 Annualization Adjustment (Line 8 - Line 9)				<u><u>\$ 367,780</u></u>

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending November 30, 2025

Exhibit MLB-2
Page 2 of 3

Line No.	12 Mos <u>November 2022</u>	12 Mos <u>November 2023</u>	12 Mos <u>November 2024</u>	Total 3 Year <u>Average</u>
1 Per Books Acct 487	\$ 1,599,988	\$ 1,897,169	\$ 1,511,996	\$ 5,009,153
2 Per Books Billed Revenue	<u>\$ 825,062,491</u>	<u>\$ 860,472,954</u>	<u>\$ 736,933,555</u>	<u>\$ 2,422,469,001</u>
3 Forfeited Discounts as a % of Revenue (Line 1 / Line 2)	0.1939%	0.2205%	0.2052%	0.2068%
4 Future Test Year Sales Revenue (Ex. 103, Page 11, Line 5)				\$ 714,458,507
5 Future Test Year Transportation Revenue (Ex. 103, Page 11, Line 8)				\$ 200,995,044
6 Total Sales and Transportation Revenue (Line 4 + Line 5)				<u>\$ 915,453,551</u>
7 3 Year Average				0.2068%
8 Annualized Forfeited Discounts (Line 7 * Line 6)				<u>\$ 1,893,158</u>
9 Future Test Year Acct 487 (Ex. 103, Page 10)				\$ 1,879,776
10 Annualization Adjustment (Line 8 - Line 9)				<u><u>\$ 13,382</u></u>

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending December 31, 2026

Exhibit MLB-2
Page 3 of 3

Line No.	12 Mos <u>November 2022</u>	12 Mos <u>November 2023</u>	12 Mos <u>November 2024</u>	Total 3 Year <u>Average</u>
1 Per Books Acct 487	\$ 1,599,988	\$ 1,897,169	\$ 1,511,996	\$ 5,009,153
2 Per Books Billed Revenue	<u>\$ 825,062,491</u>	<u>\$ 860,472,954</u>	<u>\$ 736,933,555</u>	<u>\$ 2,422,469,001</u>
3 Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.1939%	0.2205%	0.2052%	0.2068%
4 Fully Projected Future Test Year Sales Revenue (Ex. 103, Page 15, Line 5)				\$ 717,966,797
5 Fully Projected Future Test Year Transportation Revenue (Ex. 103, Page 15, Line 8)				\$ 198,991,973
6 Total Sales and Transportation Revenue (Line 4 + Line 5)				<u>\$ 916,958,770</u>
7 3 Year Average				0.2068%
8 Annualized Forfeited Discounts (Line 7 * Line 6)				<u>\$ 1,896,271</u>
9 Fully Projected Future Test Year Acct 487 (Ex. 103, Page 14)				\$ 1,893,158
10 Annualization Adjustment (Line 8 - Line 9)				<u><u>\$ 3,113</u></u>

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

V.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2025-3053499

DIRECT TESTIMONY OF
JOSEPH VASSALOTTI
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

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I. Introduction

Q. Please state your name and business address.

A. My name is Joseph Vassalotti. My business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

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

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Senior Regulatory Analyst in the Rates and Regulatory Strategy Department.

Q. Please briefly describe your professional experience.

A. I was hired as a tax associate for PricewaterhouseCoopers (PwC) in 2020, serving clients in a variety of industries including public utilities, health care, and manufacturing. I was promoted to senior associate in 2022. I was hired by NiSource in 2023 as a Senior Regulatory Analyst supporting regulatory functions for NiSource operating companies, including, but not limited to, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company").

Q. Please describe your educational background.

A. I hold a Bachelor of Business Administration degree with majors in Accounting and Pre-Law from Ohio University.

Q. What are your responsibilities in your current position?

A. My responsibilities as a Senior Regulatory Analyst include providing revenue requirement support for base rate proceedings for several NiSource companies,

1 including, Columbia and its regulated natural gas distribution affiliates in Maryland,
2 Ohio, Virginia, and Kentucky.

3 **Q. Have you previously testified before this or any other regulatory agency?**

4 A. No.

5 **Q. Please describe the purpose of your testimony in this proceeding.**

6 A. The purpose of my testimony is to present Columbia's cost of service and to quantify
7 an existing revenue deficiency based on Twelve Months Ending December 31, 2026
8 operating costs and revenues, as adjusted. As part of the cost of service analysis, my
9 testimony supports all rate making adjustments to Columbia's Cost of Service
10 Operating and Maintenance ("O&M") expenses.

11 **Q. Which exhibits are you sponsoring through your testimony?**

12 A. For the historic test year ("HTY"), I am supporting Exhibit 1, Exhibit 2, and Exhibit
13 4. For the future test year ("FTY") and fully projected future test year ("FPFTY"), I
14 am sponsoring Exhibit 101, Exhibit 102, Exhibit 104 (in coordination with Company
15 witnesses Jason Leal (Columbia Statement No. 18) and George Jonda (Columbia
16 Statement No. 15)), and Exhibit 414. I am also sponsoring portions of Exhibits 13 and
17 113. As part of the development of these items, certain sections of the financial data
18 are supported by other Columbia witnesses as identified in my testimony.

19 **Q. Are you sponsoring any additional Exhibits?**

20 A. Yes. As discussed further on in my testimony, I am sponsoring CONFIDENTIAL
21 Exhibit JV-1 providing FPFTY estimate quantification of the Company's proposal to

1 move Universal Services Operating Expense recovery of the Company's Energy
2 Assistance Team ("EAT") from base rates to Rider USP supported in the Direct
3 Testimony of Columbia witness Deborah A. Davis (Statement No. 16).

4 **Q. For each of the exhibits that you are sponsoring or co-sponsoring, were**
5 **they prepared or reviewed by you?**

6 A. Yes. All of these exhibits were prepared or reviewed by me. I have reviewed each of
7 the documents that I am sponsoring or co-sponsoring in this proceeding.

8 **Q. Were there any requirements set forth in the Company's Settlement of**
9 **its most recent base rate case at Docket No. R-2024-3046519 that you**
10 **would like to address?**

11 A. Yes, pursuant to paragraph 30 of the approved Settlement in Docket No. R-2024-
12 3046519, Columbia is required to provide a comparison of its actual revenue,
13 expenses and rate base additions for the twelve months ended December 31, 2025,
14 to the projections in the case. As actual revenue, expenses and rate base additions for
15 the twelve months ended December 31, 2025 are not yet available, the Company will
16 provide an update in its next base rate case filing.

17 **Q. What test years will you be addressing in this testimony?**

18 A. I will be addressing the twelve-month period ended November 30, 2024 as the HTY,
19 the twelve-month period ending November 30, 2025 as the FTY, and the twelve-
20 month period ending December 31, 2026 as the FPFTY.

21 **Q. What is the basis for Columbia's claim for revenue deficiency?**

1 A. Columbia's revenue deficiency is calculated utilizing a rate year ending December 31,
2 2026 for rate base, revenues and expenses, with pro forma adjustments for known
3 and measurable changes. This approach recognizes that a utility's revenues should
4 be sufficient to recover the reasonably and prudently incurred costs of providing safe
5 and reliable service to its customers, including a reasonable opportunity to earn a fair
6 rate of return on the used and useful investment that the utility has devoted to such
7 service.

8 **Q. Please summarize the results of the cost of service requirement and**
9 **resulting revenue deficiency.**

10 A. As presented on Exhibit 102, Schedule 3, Page 5, Columbia has calculated a revenue
11 deficiency of \$110,496,797 based upon the pro forma operating income at FPFTY
12 present rates for the twelve months ending December 31, 2026. Columbia's
13 computation of the revenue deficiency and revenue requirement reflects rate base of
14 \$3,845,381,715. In addition, the computation of the revenue requirement reflects
15 known and measurable changes to both utility operating income and rate base, which
16 are explained later in my testimony and in the testimonies of other Company
17 witnesses.

18 **Q. How is your testimony organized?**

19 A. I will first address the HTY, Exhibit 2 and Exhibit 4, followed by a discussion of the
20 FTY and FPFTY, Exhibit 102 and Exhibit 104.

II. HTY – Exhibit 2 – Statement of Income

Q. Please describe Exhibit 2, Schedule 3, Page 3.

A. This Exhibit is the statement of operating income, pro forma at present and proposed rates, for the HTY. Column 2 reflects the per book operating revenue, operating expenses, income taxes and utility operating income for the Company for the twelve months ended November 30, 2024. These amounts have been adjusted to reflect pro forma operating income at HTY present rates in Column 4. Column 5 adjustments are detailed in Exhibit 2, Schedule 3, Pages 5 and 6. Column 6 shows the resulting pro forma operating revenue, expenses and income for the HTY at proposed rates.

Q. Please describe the data inputs and supporting witnesses for each line of Exhibit 2, Schedule 3, Page 3.

A. Operating revenues are supplied by Company witness May Battig (Columbia Statement No. 3) and are included on Lines 1 through 13. Company witness Battig also provides the level of Gas Cost Expense and Off System Sales Expense that are included on Lines 16 and 17, respectively. These two items are exactly offsetting to the level of revenue and accordingly do not impact the base rate claim in this case; rates for these items are determined in the Company's annual gas cost proceedings. I am supporting the O&M Expense level as presented on Line 18. Lines 19 and 20, Depreciation and Amortization and Net Salvage Amortization, respectively, are provided by Company witness John J. Spanos (Columbia Statement No. 5). Taxes Other Than Income, Income Taxes, and Investment Tax Credit, Lines 21, 24 and 25,

1 respectively, have been provided by Company witness Jennifer Harding (Columbia
2 Statement No. 10), and Rate Base on Line 27 has been provided by Company witness
3 Julie Covert (Columbia Statement No. 11). The Requested Rate of Return at
4 Proposed Rates on Line 28, Column 6 is provided by Company witness Vincent V.
5 Rea (Columbia Statement No. 8). Each witness' testimony provides detailed support
6 for these items.

7 **Q. Please describe Exhibit 2, Schedule 3, Pages 4 through 6.**

8 A. Exhibit 2, Schedule 3, Page 4 presents the HTY pro forma interest expense calculated
9 by multiplying the Rate Base shown in Exhibit 8, Page 3, by the weighted cost of
10 short- and long-term debt in Exhibit 400, Page 1.

11 Exhibit 2, Schedule 3, Page 5 derives the HTY Revenue Conversion Factor on
12 lines 8 through 17. The Revenue Conversion Factor is utilized to determine the HTY
13 Revenue Deficiency on Line 7.

14 Page 6 shows a break-down of the HTY revenue requirement and the pro
15 forma uncollectible expense gross-up and gross-up for income taxes to achieve the
16 requested return on Rate Base of 8.55% shown on Exhibit 400, Page 1.

17 **III. HTY – Exhibit 4 - Operation & Maintenance Expenses**

18 **Q. What are Columbia's per books historic test year O&M Expenses?**

19 A. In the HTY, Columbia recorded \$220,882,736 in O&M Expense exclusive of gas
20 costs, as shown on Exhibit 4, Schedule 1, Page 2, Column 3. The O&M data is
21 presented in a Cost Element format, which provides a breakdown by cost causation.

1 Note, for comparative purposes, Columbia has added per book actual O&M Expenses
2 for the two years prior to the HTY in Column 1 (twelve months ended November 30,
3 2022) and Column 2 (twelve months ended November 30, 2023).

4 **Q. Did you make adjustments to the actual HTY O&M to reflect a pro forma**
5 **HTY O&M Expense level?**

6 A. Yes. I have prepared adjustments to the HTY to arrive at a pro forma level of O&M
7 Expense for this filing. The historic test year level of O&M Expense starts with O&M
8 Expense per books and was adjusted to reflect normalized and annualized levels in
9 determining the pro forma O&M Expense as summarized on Exhibit 4, Schedule 1,
10 Page 2, Column 5.

11 **Q. What adjustments has Columbia made to O&M Expense?**

12 A. The Company has reflected the following ratemaking adjustments to the HTY, each
13 of which will be explained in greater detail later in my testimony:

14 a) Labor-Related Expense adjustments to annualize and normalize payroll for
15 employees as of the end of the HTY;

16 b) An adjustment to Incentive Compensation;

17 c) An adjustment to annualize the amortization expense of the Prepaid Pension
18 Deferral;

19 d) Removal of the negative OPEB Expense;

20 e) Adjustments primarily to remove non-recoverable Outside Services
21 Expenses;

- f) Annualization of Building Rents and Leases and Corporate Insurance to latest known and measurable levels;
- g) Injuries and Damages normalized to reflect a five-year average of cash payments;
- h) Adjustment to remove non-recoverable Employee Expenses;
- i) Company Memberships adjusted to latest known and measurable level, and further adjusted to remove non-recoverable expenses;
- j) Removal of Gas Used in Company Operations;
- k) Advertising adjusted to remove non-recoverable items;
- l) Adjustment to Materials and Supplies to remove non-recoverable expenses;
- m) Adjustment to Other O&M Expenses to remove non-recurring items;
- n) Adjust assessments (fees) to latest known and measurable level;
- o) NCSC costs adjusted to annualize and normalize labor and incentive costs, and to remove non-recoverable and non-recurring items;
- p) Normalization of Rate Case Expense;
- q) Uncollectible Accounts normalized to reflect a three-year average experience, and adjust the Rider Merchant Function Charge (“MFC”) expense to match revenue;
- r) Adjust the COVID-19 Amortization Expense to reflect the on-going annualized level;
- s) Adjust Rider USP and Rider EE expense to match revenue; and

t) Adjust to include interest expense on customer deposits correlating to the reduction to rate base for the average balance of Customer Deposits supported by Columbia witness Covert.

A. Labor

Exhibit 4: Schedule 1, Page 2, Line 1; Schedule 2, Pages 1, 2, 3 and 5.

Q. Please provide a brief explanation of the labor adjustments.

A. Labor costs in the HTY were adjusted to reflect the annualized gross base salaries, or normal pay (wages), of the 715 active Columbia employees as of November 30, 2024. The difference, or annualization adjustment, was further adjusted to arrive at the net O&M Expense by applying the O&M Expense experience percentage provided on Exhibit No. 4, Schedule 2, Page 5. The annualization adjustment resulting in a reduction to O&M Expense of \$563,254 is calculated in Exhibit 4, Schedule 2, Page 1, Line 5, and a further downward adjustment of \$12,054 is applied to remove labor relating to lobbying on Line 6. The resulting total downward labor annualization and normalization adjustment of \$575,308 is removed from the actual HTY Labor O&M Expense level of \$38,096,593 in Exhibit 4, Schedule 1, Page 2, Line 1 resulting in a total pro forma HTY labor expense level of \$37,521,285.

B. Incentive Compensation

Exhibit 4: Schedule 1, Page 2, Line 2; Schedule 2, Page 4

Q. Please provide an explanation of the HTY Incentive Compensation adjustment.

1 A. Columbia's HTY per books Incentive Compensation O&M Expense of \$5,239,728
2 was decreased by \$1,416,104 to reflect the actual level of expense associated with
3 Incentive Compensation paid in 2024. This adjustment removes any out of period
4 true-ups for the prior year and adjusts the accrual made in the test year to reflect the
5 incentive compensation paid during the HTY and recognized as O&M Expense based
6 on the labor O&M Expense experience percentage for the HTY (per Exhibit 4,
7 Schedule 2, Page 5, Line 7). Detail supporting the historic test year adjustment and
8 pro forma level of expense of \$3,823,624 is provided on Exhibit 4, Schedule 2, Page
9 4.

10 **C. Prepaid Pension Deferral Amortization Expense**

11 *Exhibit 4: Schedule 1, Page 2, Line 4; Schedule 2, Page 6*

12 **Q. Please describe the ratemaking adjustment for Prepaid Pension Deferral**
13 **Amortization Expense.**

14 A. The Final Order approving the Settlement at Docket No. R-2018-2647577 permitted
15 Columbia to recover the deferred prepaid pension O&M Expense of \$8,449,772 over
16 a ten-year period starting December 16, 2018. This ratemaking entry verifies the on-
17 going annual amount of \$844,977 for amortization expense.

18 **D. OPEB – Other Post-Employment Benefits**

19 *Exhibit 4: Schedule 1, Page 2, Line 5; Schedule 2, Page 7*

20 **Q. Please describe the ratemaking adjustment for OPEB O&M Expense.**

1 A. As established in the Settlement of Columbia's base rate proceeding at Docket No. R-
2 2012-2321748, Columbia is permitted to continue to defer the difference between the
3 annual OPEB O&M Expense calculated pursuant to FASB Accounting Standards
4 Codification ("ASC") 715, "Compensation – Retirement Benefits" (SFAS No. 106) and
5 the annual OPEB O&M Expense allowance in rates of \$0. Therefore, this adjustment
6 removes the credit OPEB O&M Expense of \$1,092,603 to reflect an adjusted expense
7 level of \$0, which matches the amount currently being recovered in revenues. It is
8 important to note that the OPEB credit amount is an accounting calculation, and the
9 Company did not actually receive a credit payment.

10 **E. Outside Services**

11 ***Exhibit 4:** Schedule 1, Page 2, Line 7; Schedule 2, Pages 8 and 23*

12 **Q. Please describe the ratemaking adjustment for Outside Services.**

13 A. Ratemaking adjustments have been made to HTY per book Outside Services Expense
14 of \$17,480,882 to remove non-recoverable consulting costs associated with lobbying
15 in the amount of \$121,175 and to appropriately report \$4,105 related to RP1162
16 Public Awareness costs as Advertising discussed later in my testimony. Note, Outside
17 Services O&M Expense is further adjusted on Exhibit 4, Schedule 2, Page 23 to
18 remove \$503,085 of expense associated with Columbia's most recent base rate case,
19 Docket No. R-2024-3046519. As shown on Exhibit 4, Schedule 1, Page 2, Line 7, the
20 total reduction to Outside Services O&M Expense is \$628,365 arriving at a pro forma
21 expense of \$16,852,517.

F. Rents and Leases

Exhibit 4: Schedule 1, Page 2, Lines 8 and 9; Schedule 2, Page 9

Q. How were Rents and Leases O&M Expense adjusted for the HTY?

A. Rents and Leases O&M Expenses are categorized as a) rents and leases related to buildings, and b) other rents and leases, including communications equipment and lines, office machines and furnishings. Building Rents and Leases Expense were annualized based on current lease agreement contracts, building allocation studies, and capitalization rates on Exhibit 4, Schedule 2, Page 9 for a total of \$727,583. This amount was compared to the per book test year level of \$701,713, resulting in an increase of \$25,870. The Rents and Leases Expenses for communications equipment and lines, office machines, and other items of \$475,203 remains unchanged from the HTY per books as presented on Exhibit 4, Schedule 1, Page 2, Line 9.

G. Corporate Insurance

Exhibit 4: Schedule 1, Page 2, Line 10; Schedule 2, Page 10

Q. Please explain the Corporate Insurance O&M Expense adjustment for the historic test year.

A. Corporate Insurance includes property, casualty, workers compensation, medical stop loss, and other miscellaneous general liability insurance. Most of Columbia's policy periods are either effective June 1 through May 31, July 1 through June 30, or November 1 through October 31 of each year. Premium payments are generally made the same month as the policy effective date. The prepayment of these costs are

1 recorded and amortized over the appropriate fiscal period. The HTY adjustment
2 compares the latest known and measurable annual premium payments for
3 2024/2025 by type of coverage, and recognized as O&M Expense, totaling
4 \$4,320,454 to the per book expense recognized during the period of \$4,449,152
5 resulting in a downward adjustment to Corporate Insurance O&M Expense of
6 \$128,698. Detailed calculations of these adjustments have been provided on Exhibit
7 4, Schedule 2, Page 10.

8 **H. Injuries and Damages**

9 ***Exhibit 4:** Schedule 1, Page 2, Line 11; Schedule 2, Page 11*

10 **Q. Was an adjustment made for Injuries and Damages?**

11 A. Yes. The HTY expense level for Injuries and Damages of \$385,759 represents expense
12 for claims paid, accruals for claims anticipated to be paid, and other accounting
13 adjustments. A downward adjustment of \$3,880 was made to normalize the level of
14 Injuries and Damages O&M Expense based upon a five-year average actual cash paid
15 for claims in today's dollars using a Gross Domestic Product Implicit Price Deflator
16 ("GDPIPD"), or inflation factor, arriving at a pro forma level of expense of \$381,879.
17 As in previous base rate cases, a five-year average is used to reflect a normalized
18 experience of claims paid consistent with the recognition of cash paid in the test year
19 in other ratemaking adjustments, such as Incentive Compensation discussed above.
20 Detail supporting this adjustment is shown on Exhibit 4, Schedule 2, Page 11.

I. Employee Expenses

Exhibit 4: Schedule 1, Page 2, Line 12; Schedule 2, Page 12

Q. Was an adjustment made for Employee Expenses?

A. Yes. A downward adjustment of \$187,192 was made to the HTY Employee Expenses O&M Expense of \$1,474,438 to remove non-recoverable employee expenses Columbia is not seeking to include for recovery in this proceeding. The resulting pro forma level expense for Employee Expenses is \$1,287,246. Details supporting this adjustment are shown on Exhibit 4, Schedule 2, Page 12.

J. Company Memberships

Exhibit 4: Schedule 1, Page 2, Line 13; Schedule 2, Page 13

Q. Please explain the adjustments made to Company Memberships.

A. The HTY expense for Company Memberships of \$699,071 has been adjusted as follows: (1) to annualize American Gas Association dues to reflect known and measurable current payments for calendar year 2024; (2) to remove a non-recoverable Company Membership expense (in Exhibit 4, Schedule 2, Page 13, Column 2, Line 4); and (3) to remove costs identified as lobbying. The total adjustment to Company Memberships resulted in a downward adjustment of \$30,986 arriving at a pro forma level of expense of \$668,085. The details of these adjustments are shown on Exhibit 4, Schedule 2, Page 13.

K. Utilities and Company Used Gas

Exhibit 4: Schedule 1, Page 2, Line 14; Schedule 2, Page 14

1 **Q. What does the HTY adjustment to Utilities and Company Used Gas**
2 **represent?**

3 A. A decrease to HTY Utilities and Company Used Gas O&M Expense of \$473,830 is
4 made to eliminate costs associated with the contra gas cost expense Account 812 for
5 activity related to Company-used gas recovered through Columbia's annual
6 Purchased Gas Cost case. This adjustment recognizes the inclusion of the amounts
7 as both gas cost recovery and gas purchase expense. Columbia includes the expenses
8 associated with gas used in Company operations when establishing its gas cost
9 recovery rates. The purchased gas is recorded as system supply and then reclassified
10 from gas purchase (by a credit to Account 812) to various O&M Expense accounts.
11 Therefore, it is necessary to remove the amount above from O&M Expense for the
12 purposes of calculating base rates and appropriately show this same level of expense
13 in gas purchase expense along with an offsetting gas recovery level. The remaining
14 HTY level of \$2,573,883 represents other utility costs, such as electric and
15 telecommunications (internet service, cell phones, land lines, etc.), not recovered
16 through the Section 1307(f) process.

17 **L. Advertising**

18 ***Exhibit 4: Schedule 1, Page 2, Line 15; Schedule 2, Page 15***

19 **Q. Was Advertising Expense adjusted?**

20 A. Yes. Columbia made the following adjustments to its Advertising O&M Expense: (1)
21 to remove \$187,274 in non-recoverable brand advertising; (2) to remove \$3,609

1 related to other non-recoverable misclassified items; and (3) to include, and
2 appropriately reflect, \$106,616 of RP1162 Public Awareness expense inadvertently
3 classified as Outside Services, Material & Supplies, and Other O&M as Advertising.
4 These changes resulted in a reduction to Advertising Expense of \$84,268. Please see
5 Exhibit 4, Schedule 2, Page 15 for details.

6 **M. Materials and Supplies**

7 ***Exhibit 4:** Schedule 1, Page 2, Line 17; Schedule 2, Pages 16 and 23*

8 **Q. Was an adjustment made to Material and Supplies Expense?**

9 A. Yes. Columbia has made an adjustment to the HTY per books Materials and Supplies
10 Expense of \$7,687,836 to remove lobbying Materials and Supplies O&M Expense in
11 the amount of \$3,247, and to reflect \$3,711 in RP1162 Public Awareness costs as
12 Advertising, as discussed above. Please see Exhibit 4, Schedule 2, Page 16 for details.
13 Note, Materials and Supplies O&M Expense is further adjusted on Exhibit 4,
14 Schedule 2, Page 23 to remove \$58,476 of expense associated with Columbia's most
15 recent base rate case, Docket No. R-2024-3046519. As shown on Exhibit 4, Schedule
16 1, Page 2, Line 17, the total reduction to Materials and Supplies O&M Expense is
17 \$65,434 arriving at a pro forma expense of \$7,622,402.

18 **N. Other O&M**

19 ***Exhibit 4:** Schedule 1, Page 2, Line 18; Schedule 2, Page 17*

20 **Q. Was an adjustment made to Other O&M Expense?**

1 A. Yes. Columbia made an adjustment to per book HTY Other O&M Expenses of
2 \$1,022,147 to remove a non-recurring penalty in the amount of \$810,000 and to
3 report \$98,800 in RP1162 Public Awareness costs as Advertising, as discussed above,
4 in arriving at a pro forma expense of \$113,347 presented on Exhibit 4, Schedule 1,
5 Page 2, Line 18. Please see Exhibit 4, Schedule 2, Page 17 for details.

6 **O. Commission, OCA and OSBA Assessments**

7 *Exhibit 4: Schedule 1, Page 2, Line 19; Schedule 2, Page 18*

8 **Q. Please explain the increase to the HTY Public Utility Commission**
9 **(“Commission”), Office of Consumer Advocate (“OCA”) and Office of**
10 **Small Business Advocate (“OSBA”) Assessment expenses.**

11 A. The increase to Commission, OCA and OSBA expense of \$434,364 is necessary to
12 reflect a level of expense based on the most current amount invoiced for Commission,
13 OCA and OSBA assessments. The normalized test year expense amount of
14 \$3,299,312 reflects the most recent invoiced amount received (September 6, 2024)
15 as of the submission of this base rate filing.

16 **P. NiSource Corporate Services Company (“NCSC”)**

17 *Exhibit 4: Schedule 1, page 2, Line 20; Schedule 2, Pages 19-22 and Page 23*

18 **Q. Please explain the structure and role of NCSC.**

19 A. NCSC is a subsidiary of NiSource and an affiliate of Columbia within the NiSource
20 corporate organization. NCSC was established to provide centralized services to the
21 individual operating companies within NiSource and to coordinate the allocation and

1 billing of charges to the NiSource operating companies for services provided by both
2 NCSC directly and by third-party vendors. The rendering of services on a centralized
3 basis enables the affiliates to realize benefits of personnel with specialized areas of
4 expertise, as well as the use of assets, without bearing the full cost of each
5 individually, as the costs are shared among the affiliates. Thus, NCSC offers
6 Columbia, as well as the other NiSource distribution companies, access to the depth
7 and breadth of professional experience that may not otherwise be available, or that
8 may be available from consultants at much higher costs.

9 **Q. Is there a contract between Columbia and NCSC?**

10 A. Yes. NCSC has executed an individual Service Agreement with each affiliate, which
11 designates the types of services to be performed and the method of calculating the
12 charges for these services. The current Service Agreement between NCSC and
13 Columbia became effective January 1, 2015. A copy of the Service Agreement is
14 provided as Exhibit 4, Schedule 11, Attachment C. Other detailed information
15 regarding NCSC is also provided as a part of Exhibit 4, Schedule 11.

16 **Q. How are NCSC's costs billed to affiliates?**

17 A. There are two types of billings made to affiliates, including Columbia: 1) contract
18 billing and 2) convenience billing.

19 **Q. Please explain the difference between the NCSC contract and**
20 **convenience billings.**

1 A. Contract billings represent NCSC labor and costs billed to the respective affiliate and
2 are identified by billing pools. Contract billed charges may be direct (i.e., billed
3 directly to a single affiliate or function, e.g. Columbia Gas of Pennsylvania), or
4 allocated (i.e., split between or among several affiliates), depending on the nature of
5 the costs. Convenience billings reflect payments that are routinely made by NCSC on
6 behalf of affiliates on an ongoing basis, including employee benefits, corporate
7 insurance, leasing, and external audit fees. Each affiliate is billed for its proportional
8 share of the payments made in that respective month. As the name implies,
9 convenience billing is intended as a convenience because it eliminates the need for
10 vendors to separately invoice each affiliate entity receiving the same services. NCSC
11 pays the invoice and directly records the charges on the books of the affiliate.

12 **Q. How does NCSC determine charges applicable to Columbia?**

13 A. NCSC is regulated by the Federal Energy Regulatory Commission ("FERC").
14 Pursuant to FERC Order No. 684 issued October 19, 2006, centralized service
15 companies (like NCSC) must use a cost accumulation system, provided such system
16 supports the allocation of expenses to the services performed and readily identifies
17 the source of the expense and the basis for the allocation. In compliance with FERC
18 Order No. 684, NCSC uses a billing pool system to collect costs that are applicable
19 and billable to affiliates, including Columbia. NCSC directs all personnel to charge an
20 affiliate directly whenever possible so that costs associated with services rendered to
21 affiliates can be directly billed. This allows a user to directly bill a single company for

1 costs incurred (e.g., 0037 – representing Columbia Gas of Pennsylvania). Allocated
2 billing pools (e.g., 00AD – representing the five Columbia Gas Distribution
3 Companies) allow a user to charge multiple companies for costs incurred and should
4 only be used if direct billing is not feasible. For instance, some projects or services
5 necessarily involve more than one affiliate, and in that case, the billing pool system
6 details how expenses are allocated among the participating affiliates, including
7 Columbia.

8 **Q. Are NCSC's charges for services rendered to Columbia billed at cost?**

9 A. Yes. In accordance with Section 2.2 of the Service Agreement all services are provided
10 at cost, including compensation for use of capital.

11 **Q. Please describe the controls in place to ensure that an affiliate is**
12 **consistently and appropriately billed.**

13 A. NCSC allocates costs for a particular billing pool in accordance with the bases of
14 allocation filed annually with FERC. A description of each of the bases of allocations
15 are provided in the Service Agreement (See Ex. 4, Sch. 11, Att. C). NCSC currently
16 updates the statistical data used in the approved allocation bases, at a minimum, on
17 a semi-annual basis; and furthermore, prior to publishing the new allocation
18 percentages, NCSC provides Columbia's leadership team the opportunity to review,
19 discuss, and provide feedback. There are system controls in place that restrict certain
20 departments, or groups of departments, to only use billing pools that allocate to
21 companies benefitting from the services those departments provide. Essentially, a

department that supports only the operating affiliates would only be allowed to use billing pools that include the operating affiliates. If an individual would attempt to use a different billing pool, the related accounting systems would prompt an immediate error and not allow data to be input.

Q. Please provide a brief overview of NCSC Exhibit 4, Schedule 2, Page 19.

A. Exhibit 4, Schedule 2, Page 19, Line 1 provides the HTY gross (O&M and non-O&M Expense) NCSC contract billed charges to Columbia. As shown on Line 2, a portion of the billings are recorded to non-O&M accounts (balance sheet or non-utility expenses). The NCSC HTY contract billed charges to Columbia recorded to O&M Expense of \$83,618,250 are displayed on Line 3.

Q. Please explain the adjustments made to the NCSC HTY O&M Expense.

A. Exhibit No. 4, Schedule No. 2, Page 19, Lines 4 through 14 reflect adjustments made to the NCSC HTY O&M Expense as follows:

Line 4 – Adjusts the NCSC Incentive Compensation Expense to the amount paid in 2024 using the percentage of Total NCSC labor billed to Columbia experienced during the HTY and recognized as O&M Expense. This calculation is detailed on Page 20 resulting in a reduction to NCSC O&M Expense of \$2,273,944.

Line 5 - Annualizes Columbia's NCSC billed gross labor, payroll taxes and benefits as detailed on Page 21 resulting in an increase to NCSC O&M Expense of \$1,395,748. The NCSC labor, payroll taxes and benefits O&M Expense adjustment is determined by applying Columbia's percentage of NCSC labor charged to O&M

Expense experienced during the HTY as derived on Exhibit 4, Schedule 2, Page 22, Line 4.

Lines 6 through 11 –Removes \$502,751 from the Company’s NCSC O&M Expense for lobbying, brand advertising, charitable contributions, and other identified non-recoverable expenses.

Lines 12 through 14 – Removes \$602,699 for HTY non-recurring costs from the Company’s NCSC O&M Expense associated with termination of the lease agreement for the Smithfield Customer Care Center (“CCC”) facility in May 2024.

Additionally, Columbia’s NCSC O&M Expense is further adjusted on Exhibit 4, Schedule 2, Page 23 to remove \$725 of expense associated with Columbia’s most recent base rate case, Docket No. R-2024-3046519. As shown on Exhibit 4, Schedule 1, Page 2, Line 20, the total reduction to Columbia’s NCSC O&M Expense is \$1,984,371 arriving at a pro forma expense of \$81,633,879.

Q. Rate Case Expense Normalization

Exhibit 4: Schedule 1, Page 2, Line 22; Schedule 2, Page 23

Q. Has the Company included a normalized level of Rate Case Expense in its HTY Cost of Service?

A. Yes. As discussed above, actual Rate Case Expense incurred during the HTY for the Company’s prior base rate case, Docket No. R-2024-3046519, has been removed from the per books HTY Materials and Supplies, NCSC, and Outside Services O&M Expenses as shown on Lines 1 through 3 of Exhibit 4, Schedule 2, Page 23. In

1 addition, on Line 5, I have included a proposed estimate for the normalized level of
2 rate case expense for the current case, which is detailed in Exhibit 104, Schedule 2,
3 Page 16. The Company is proposing a one-year normalization period due to prior
4 base rate case filing experience and the expectation of future annual base rate case
5 filings.

6 **R. Uncollectible Accounts Expense**

7 (Uncollectible Accounts & Uncollectible Accounts – Unbundled Gas)

8 ***Exhibit 4: Schedule 1, Page 2, Line 23 & 24; Schedule 2, Pages 24-26***

9 **Q. Please explain Columbia's recovery of Uncollectible Accounts Expense.**

10 A. Columbia recognizes two categories of uncollectible accounts: (1) Non-CAP
11 uncollectible accounts and (2) Customer Assistance Program ("CAP") uncollectible
12 accounts. Non-CAP Uncollectible Accounts Expense is determined in the cost of
13 service by using a three-year average net write-off rate, which is developed on Exhibit
14 4, Schedule 2, Page 24 whereas the CAP Uncollectible Accounts Expense (related to
15 the CAP shortfall) is recovered through Rider USP discussed later in my testimony.

16 **Q. What years are included in the calculation of the three-year average net**
17 **write-off experience factor in determining the normalized Uncollectible**
18 **Accounts Expense for this proceeding?**

19 A. The Company proposes to use the most current data for the Twelve Months Ended
20 November 30, 2022, 2023 and 2024 to determine an uncollectible experience factor
21 to produce normalized uncollectible expense for the HTY, FTY and FPFTY.

1 **Q. Please explain the development of the HTY Uncollectible Accounts**
2 **Expense normalization.**

3 A. Exhibit 4, Schedule 2, Pages 24 through 26 set forth the development of a percentage
4 for uncollectible accounts related to normal average charge-offs recovered through
5 base rates. The net write-off percentage for charge-offs related to Non-CAP customer
6 uncollectible accounts recovered through base rates is calculated based on comparing
7 the three-year average of charge-offs for normal uncollectible accounts expense to
8 billed revenue for the Twelve Months Ended November 30, 2022, 2023 and 2024.
9 Several adjustments to billed revenue are necessary to develop the net write-off
10 percentage. First, account charge-offs lag billed revenue by approximately 120 days,
11 or 4 months. This lag in days includes consideration for the time between original
12 billing and an account being placed into final status, as well as consideration for the
13 average time between an account being placed into final status and termination of
14 service, which is when the account is charged-off to expense. I used billed revenue for
15 the Twelve Months Ended July 31 of each year to appropriately reflect the lag (4
16 months) between the billing and write-off of accounts.

17 Additionally, I provided, on Page 25, the average net write-off rate for
18 Residential customers, as well as the combined net write-off rate for Commercial and
19 Industrial (“C&I”) customers. This information is utilized by Company witness Battig
20 (Columbia Statement No. 3) in the development of the rate utilized in the revenue
21 and expense recovery for the Rider Merchant Function Charge (“MFC”).

1 **Q. What other adjustments were made to billed revenue?**

2 A. Columbia's Distributive Information System ("DIS") billing system is used to bill all
3 Residential and small C&I accounts and therefore, includes revenues applicable to
4 CAP customer accounts. Exhibit 4, Schedule 2, Line 2 of Page 25, titled "Total DIS
5 Billed Revenue," has been adjusted to remove the revenue associated with
6 Columbia's CAP (Page 26) as CAP uncollectible is accounted for in Rider USP.
7 Exhibit 4, Schedule 2, Line 4 of Page 25 represents Adjusted DIS Billed Revenue (or
8 non-CAP customer revenues) related to the net write-offs presented on Exhibit 4,
9 Schedule 2, Line 9 of Page 24.

10 **Q. How were the net write-offs shown on Line 9 developed?**

11 A. The net write-offs shown on Exhibit 4, Schedule 2, Line 9 of Page 24 represent the
12 total uncollectible accounts charged-off and recovery of Uncollectible Accounts
13 Expense for all customers billed through DIS.

14 **Q. How are the adjusted (non-CAP) billed revenue and net write-off**
15 **amounts used in the development of normalized Uncollectible Accounts**
16 **Expense?**

17 A. The three-year periods of adjusted (non-CAP) revenue are summed to generate the
18 total revenue shown on Exhibit 4, Schedule 2, Page 24, Column 4, Line 4. Similarly,
19 a three-year total is summed for net write-offs on Line 9. An uncollectible net write-
20 off rate is then calculated by dividing the three-year total net write-offs by the three-
21 year total adjusted (non-CAP) revenues on Line 10. The average net write-off rate is

1 then applied to the annualized HTY DIS revenue provided by Company witness
2 Battig. The result is Columbia's total adjusted HTY normalized Uncollectible
3 Accounts Expense for non-CAP DIS billed customers on Line 16 totaling
4 \$10,629,055, and further identified as base rate recovery of \$9,459,959 and Rider
5 MCF recovery (Uncollectible Accounts – Unbundled Gas) of \$1,169,096 in Columns
6 7 and 8, respectively.

7 **Q. Does this fully describe all adjustments made to the HTY Uncollectible**
8 **Accounts Expense?**

9 A. Yes. While DIS is one of three billing systems used to bill revenue related to normal
10 uncollectible write-offs, the Company had no write-offs from the other billing
11 systems.

12 **Q. Please summarize Columbia's proposed normalized HTY Uncollectible**
13 **Accounts Expense adjustments.**

14 A. The historic normalized uncollectible adjustments are a net increase to expense of
15 \$1,653,206 as shown on Exhibit 4, Schedule 1, Page 2, Lines 23 and 24 with
16 \$1,399,679 reflective of an increase in base rate uncollectible expense developed by
17 comparing the normalized non-CAP DIS net write-offs described above to the actual
18 HTY uncollectible expense, and \$253,527 representing an increase in Rider MFC
19 expense to match annualized revenues supported by Columbia witness Battig As
20 Rider MFC expense matches revenue because the mechanism is fully reconciled,
21 there is no impact to the HTY revenue deficiency for this adjustment.

1 **S. Amortization of Deferred COVID-19 Uncollectible Expense**

2 ***Exhibit 4:** Schedule 1, Page 2, Line 26; Schedule 2, Page 27*

3 **Q. Has the HTY been adjusted to reflect the appropriate amount of COVID-**
4 **19 Uncollectible Expense amortization?**

5 A. Yes. According to the Settlement in the Company's 2022 base rate proceeding,
6 Docket No. R-2022-3031211, the Company is permitted to amortize the regulatory
7 asset of \$2,832,363 over a four year period, or \$708,091 annually.

8 **T. Rider USP and Rider EE Costs**

9 (Uncollectible CAP – Rider USP & Rider USP – LIURP/Energy Efficiency)

10 ***Exhibit 4:** Schedule 1, Page 2, Line 27 & 28; Schedule 2, Page 28*

11 **Q. Are you sponsoring an adjustment for Rider USP and Rider EE costs as**
12 **well?**

13 A. Yes. Rider USP and Rider EE adjustments have been made to the HTY as shown on
14 Exhibit 4, Schedule 2, Page 28.

15 **Q. Please explain the test year adjustment.**

16 A. The adjustment is a result of the matching of expenses to revenue, as Rider USP and
17 Rider EE are fully reconciled mechanisms. As shown in Exhibit 3, Page 10, the
18 normalized/annualized HTY Rider USP and Rider EE revenues are \$31,769,765 and
19 \$1,232,368, respectively. Accordingly, the O&M Expense adjustment is necessary to
20 match the expenses with the revenues supported by Company witness Battig. The
21 Rider USP and Rider EE adjustments, and Rider MFC adjustment discussed above,

1 result in a net zero impact to operating income and do not have an impact on the HTY
2 revenue deficiency because the expense offsets revenue. Similarly, the pro forma
3 expenses for Rider USP, Rider EE, and Rider MFC, as discussed above, do not have
4 an impact on the FPFTY base rate increase requested in this case.

5 **U. Interest on Customer Deposits**

6 ***Exhibit 4: Schedule 1, Page 2, Line 29; Schedule 2, Page 29***

7 **Q. Please explain the adjustment for Interest on Customer Deposits.**

8 A. An adjustment for Interest on Customer Deposits is necessary to recognize the
9 expense related to interest recorded on customer deposits for the purposes of
10 ratemaking. Consistent with prior base rate cases, customer deposits are considered
11 a source of cost-free capital and as such, have been included as a reduction to rate
12 base in this case, as supported by Columbia witness Covert. As the deposits are owed
13 to the customer with interest, a ratemaking adjustment is made to recognize the
14 interest expense as an above-the-line O&M Expense related to the average customer
15 deposit balance. As presented in Exhibit 4, Schedule 2, Page 29, the adjustment is
16 calculated by applying the current 2024 interest rate on customer deposits of 8%
17 (established under Chapter 14 of the Public Utility Code) applied to the average
18 customer deposit balance. No further adjustment is made to this item for either the
19 FTY or the FPFTY because the Company has made no projected change to the HTY
20 balance for customer deposits.

IV. FTY/FPFTY – Exhibit 102 – Statement of Income

Q. Is Exhibit 102 presented in the same format as Exhibit 2?

A. Yes. Exhibit 102, Schedule 3 is a Statement of Income presenting the HTY, FTY and FPFTY at Present Rates and the FPFTY at Proposed Rates. Note, Columbia has included HTY information on Exhibit 102, Schedule 3, Page 3 for comparison purposes. Exhibit 102, Schedule 3, Page 3, as referenced earlier in my testimony when describing Exhibit 2, Schedule 3, Page 3, utilizes data that has been provided by other witnesses in this case to determine the revenue requirement.

Q. Please describe Exhibit 102.

A. This Exhibit begins with the per books HTY in Column 2, followed by the HTY adjustments in Column 3 to arrive at the Pro Forma HTY at Present Rates in Column 4. Next, in Column 5 are the FTY adjustments to arrive at Pro Forma FTY at Present Rates in Column 6. Column 7 provides the FPFTY adjustment needed to arrive at Pro Forma FPFTY at Present Rates in Column 8. Last, the revenue deficiency of \$110,496,797 necessary to achieve a reasonable opportunity to earn a fair rate of return in Column 9 is made in determining the FPFTY at Proposed Rates in Column 10. The various exhibits in support of the adjustments at present and proposed rates are identified in Column 1.

Q. Please explain Exhibit 102, Schedule 3, Page 4.

A. This page presents the calculations of synchronized interest expense using the FTY rate base multiplied by the weighted cost of short- and long-term debt on Lines 1

1 through 3, and similarly for the FPFTY year rate base and weighted cost of short- and
2 long-term debt on Lines 4 through 6.

3 **Q. Please explain Pages 5 and 6 of Exhibit 102, Schedule 3.**

4 A. Page 5 of Exhibit 102, Schedule 3 presents the calculation of the revenue deficiency
5 of \$110,496,797 on Line 7 using the FTY/FPFTY Revenue Conversion Factor, applied
6 to the Operating Income Deficiency on Line 5. The FTY/FPFTY Revenue Conversion
7 Factor calculation on Lines 8 through 17 accounts for additional uncollectible
8 expense associated with the revenue deficiency, as well as income taxes. The current
9 (2025) State Corporate Net Income Tax rate of 7.99% is adjusted to reflect the
10 effective tax rate for calendar year 2026 (FPFTY) of 7.49% as discussed by Company
11 witness Harding. The Federal Corporate Net Income Tax rate is applied at 21% to
12 arrive at Adjusted Operating Income as a percent of Total Operating Revenues. Page
13 6 shows a break-down of the FPFTY revenue deficiency and the pro forma expense
14 adjustment and income taxes to achieve the requested return of 8.55% shown on
15 Exhibit 400, Page 1, supported by Columbia witness Rea.

16 **V. FTY/FPFTY – Exhibit 104 – Operations and Maintenance Expenses**

17 **Q. Did the Company utilize a budget-based methodology to determine O&M**
18 **Expense for the FTY and the FPFTY, as Columbia has done in prior base**
19 **rate case proceedings?**

20 A. Yes. FTY and FPFTY levels of O&M Expense begin with the budget as supplied and
21 supported by Company witness Leal (Columbia Statement No. 18) and Company

1 witness Jonda (Columbia Statement No. 15). A monthly presentation of the FTY and
2 FPFTY O&M Expense budgets can be found on Exhibit 104, Schedule 1, Pages 5 and
3 6. Ratemaking adjustments have been made to normalize and annualize the budgets
4 to arrive at Pro Forma FTY and FPFTY O&M Expenses.

5 **Q. Please describe Exhibit 104, Schedule 1.**

6 A. Exhibit 104, Schedule 1 contains a total of six pages and provides a clear distinction
7 between “Budget Amounts” and “Ratemaking Adjustments” for both the FTY and the
8 FPFTY. Company witnesses Leal and Jonda are supporting all budget amounts,
9 while I support all ratemaking adjustments with certain sections of the financial data
10 supported by other Columbia witnesses as identified.

11 **Q. Please provide a brief description of each of the 6 pages of Exhibit 104,**
12 **Schedule 1.**

13 A. Page 1 references Pages 2 – 6 of the Exhibit.

14 Page 2 is the summary view of Normalized O&M Expense for all test years in
15 this case. Column 1 presents the HTY, Column 3 presents the FTY and Column 5
16 presents the FPFTY. Columns 2 and 4 provide both the differences needed to arrive
17 at budgeted amounts (HTY to the FTY, and the FTY to the FPFTY) and the
18 ratemaking adjustments applied to each of the test years.

19 Pages 3 and 4 are formatted in a similar manner. Page 3 contains details for
20 the FTY; while page 4 contains the details for the FPFTY. Page 3 starts with the
21 Normalized HTY in Column 1, followed by the differences (Column 2) between the

1 Normalized HTY and the Budgeted FTY (Column 3) supported by Company
2 witnesses Leal and Jonda. Columns 4 and 5 provide Ratemaking Adjustments and
3 Exhibit references, followed by the Normalized FTY (Column 6). Similarly, Page 4
4 provides the details for the FPFTY, starting with the Normalized FTY (Column 1;
5 from Page 3, Column 6) followed by the differences (Column 2) between the
6 Normalized FTY and the Budgeted FPFTY (Column 3) supported by Company
7 witnesses Leal and Jonda. Columns 4 and 5 provide Ratemaking Adjustments and
8 References followed by the Normalized FPFTY (Column 6).

9 Pages 5 and 6 provide the monthly Budget Data for FTY (Page 5) and FPFTY
10 (Page 6), supported by Company witnesses Leal and Jonda.

11 **Q. Did you utilize the O&M budget for all the O&M items in Exhibit No. 104?**

12 A. No. Lines 1 through 20 in Exhibit No. 104, Schedule No. 1, Column 3, Pages 3 and 4
13 reflect the O&M budget data used in the FTY and FPFTY periods. The O&M budget
14 data was not utilized for the cost items noted on Lines 22 through 28 of these same
15 Pages. These items include:

- 16 • Line 22 – Rate Case Expense – the amounts reflect normalized costs
17 associated with the current case that should be included in the revenue
18 requirement in this case.
- 19 • Lines 23– Uncollectible Accounts – the uncollectible expense is reflective of
20 the standard practice of using a three-year average of net write-off experience
21 of FTY and FPFTY revenues as provided by Company witness Battig.

- Lines 24 – Uncollectible Accounts – Unbundled-Gas (or Rider MFC) – the expense is adjusted to reflect the amounts included in revenue as provided by Company witness Battig.
- Line 25 – COVID-19 Uncollectible Expense amortization – the amounts reflect annualized COVID-19 amortization expense.
- Lines 26 and 27 – Rider USP and Rider EE – the expenses are adjusted to reflect the amounts included in revenues as provided by Company witness Battig.
- Line 28 – Interest on Customer Deposits – the below-the-line expense is not included in the O&M budget as it is an adjustment reflected as an above-the-line O&M Expense for the purposes of ratemaking and consistent with prior Columbia cases, as described earlier in my testimony.

Q. What types of adjustments is Columbia proposing to O&M Expense for the FTY and FPFTY?

A. The Company proposes the following ratemaking adjustments to determine Pro Forma O&M Expense for the FTY and FPFTY, which I will explain in detail later in my testimony:

- a) Annualization and normalization of Labor and Labor-Related Expenses;
- b) An adjustment to annualize the amortization expense of the Prepaid Pension Deferral;
- c) Removal of the negative OPEB Expense;

- d) Adjustment to remove non-recoverable Outside Services Expenses;
- e) Annualization of Building Rents and Leases and Corporate Insurance to latest known and measurable levels
- f) Injuries and Damages normalized to reflect the HTY five-year average of cash payments, plus inflation;
- g) Adjustment to remove non-recoverable Employee Expenses;
- h) Adjustment to remove non-recoverable Company Membership Expenses;
- i) Removal of Gas Used in Company Operations;
- j) Advertising, Materials & Supplies and Other O&M Expense adjusted to remove a level of non-recoverable expense;
- k) NCSC costs adjusted to annualize and normalize labor and to remove non-recoverable items;
- l) Normalization of Rate Case Expense;
- m) Uncollectible Accounts normalized to reflect the HTY three-year average experience, and adjust the Rider MFC expense to match revenue;
- n) Amortization of COVID-19 Uncollectible Expense to reflect the on-going annualized level;
- o) Adjust Rider USP and Rider EE expense to match revenue; and
- p) Adjust to include interest expense on customer deposits correlating to the reduction to rate base for the average balance of Customer Deposits supported by Columbia witness Covert.

1 **A. Labor**

2 ***Exhibit 104:*** *Schedule 1, Pages 2, 3 and 4, Line 1; Schedule 2, Page 1*

3 **Q. Please provide a brief explanation of the Labor adjustments.**

4 A. Columbia has determined annualization adjustments for the FTY of \$458,769 and
5 for the FPFTY of \$384,288. These adjustments apply annual merit and union
6 contract pay increases to the HTY ended November 30, 2024, annual base salaries
7 and lobbying adjustments. Labor adjustments further reflect an O&M percentage of
8 50.57% as determined on Exhibit 4, Schedule 2, Page 5. The resulting Labor
9 adjustments annualize Labor for the entirety of the FTY and FPFTY. The lobbying
10 adjustment is based on the HTY adjustment, plus 3% for 2025 and 2026 per year to
11 account for wage increases.

12 **B. Prepaid Pension Deferral Amortization Adjustment**

13 ***Exhibit 104:*** *Schedule 1, Pages 2, 3 and 4, Line 4; Schedule 2, Page 2*

14 **Q. Please describe the ratemaking adjustment for Prepaid Pension Deferral**
15 **Amortization.**

16 A. The Final Order approving the Settlement of Columbia's base rate case at Docket No.
17 R-2018-2647577 permits Columbia to recover the deferral of prepaid pension O&M
18 expense of \$8,449,772 over a ten year period starting December 16, 2018. This
19 ratemaking adjustment is necessary to reflect the on-going annual amortization
20 amount of \$844,977 for the FTY and FPFTY.

C. OPEB – Other Post-Employment Benefits

Exhibit 104: *Schedule 1, Pages 2, 3 and 4, Line 5; Schedule 2, Page 3*

Q. Please explain the ratemaking adjustment for OPEB Expense as approved in the Company's prior rate case.

A. Paragraph Nos. 30 and 31 of the Settlement Agreement of the Company's 2018 base rate case provide:

30. As established in the settlement of Columbia's base rate proceeding at R-2012-2321748, Columbia will be permitted to continue to defer the difference between the annual OPEB expense calculated pursuant to FASB Accounting Standards Codification ("ASC") 715, Compensation – Retirement Benefits (SFAS No. 106) and the annual OPEB expense allowance in rates of \$0. Only those amounts attributable to operation and maintenance would be deferred and recognized as a regulatory asset or liability. To the extent the cumulative balance recorded reflects a regulatory asset, such amount will be collected from customers in the next rate proceeding over a period to be determined in that rate proceeding. To the extent the cumulative balance recorded reflects a regulatory liability, there will be no amortization of the (non-cash) negative expense, and the cumulative balance will continue to be maintained.

31. Commencing with the effective date of rates, Columbia will deposit amounts in the OPEB trusts when the cumulative gross annual accruals calculated by its actuary pursuant to ASC 715 are greater than \$0. If annual amounts deposited into OPEB trusts, pursuant to this Settlement, exceed allowable income tax deduction limits, any income taxes paid will be recorded as negative deferred income taxes, to be added to rate base in future proceedings.

Q. Is the Company proposing a change to these provisions?

1 A. No. Total OPEB Expense at the end of the HTY is less than zero and the expected
2 OPEB Expense budget per the Company's actuarial studies continues to reflect a
3 credit to expense. Therefore, the Company proposes to continue using this
4 ratemaking treatment for OPEB Expense.

5 **Q. Do the ratemaking adjustments for OPEB Expense presented on Exhibit**
6 **104, Schedule 2, Page 3 comply with the provisions listed above?**

7 A. Yes, the FTY and FPFTY adjustments remove the credit OPEB expense of \$1,242,222
8 and \$1,343,082, respectively, from the budget to reflect an adjusted expense level of
9 \$0. These credit amounts are not projected cash receipts and are the result of
10 accounting credits.

11 **D. Outside Services**

12 ***Exhibit 104:*** *Schedule 1, Pages 2, 3 and 4, Line 7; Schedule 2, Page 4*

13 **Q. Please explain the adjustment to Outside Services for the FTY and**
14 **FPFTY.**

15 A. The FTY and the FPFTY include adjustments to remove Lobbying Expenses, utilizing
16 the HTY adjustment as the basis, plus inflation.

17 **E. Rents and Leases**

18 ***Exhibit 104:*** *Schedule 1, Pages 2, 3 and 4, Line 8 & 9; Schedule 2, Pages 5 & 6*

19 **Q. Please explain the adjustment to Building Rents and Leases for the FTY**
20 **and FPFTY.**

1 A. Known and measurable changes to Building Rents and Leases attributable to
2 contractual levels, building allocation studies, and current capitalization rates are
3 included on Exhibit 104, Schedule 2, Page 5 and 6 resulting in a decrease to the
4 budget of \$18,755 for the FTY and an increase of \$17,705 for the FPFTY.

5 **F. Corporate Insurance**

6 *Exhibit 104 Schedule 1, Pages 2, 3 and 4, Line 10; Schedule 2, Page 7*

7 **Q. Were adjustments made to Corporate Insurance?**

8 A. Yes, the FTY and FPFTY O&M Expenses for Corporate Insurance were adjusted to
9 reflect the latest known and measurable HTY annualized corporate insurance
10 premiums for the 2024/2025 policy periods, plus an applicable inflationary
11 adjustment in deriving the FPFTY pro forma O&M Expense resulting in a decrease
12 in FTY expense of \$471,340 and decrease to the FPFTY of \$481,175.

13 **G. Injuries and Damages**

14 *Exhibit 104: Schedule 1, Pages 2, 3 and 4, Line 11; Schedule 2, Page 8*

15 **Q. Were adjustments made to Injuries and Damages?**

16 A. Yes. The FTY and FPFTY expense levels for Injuries and Damages were adjusted to
17 reflect the pro forma HTY level of expense plus applicable inflationary adjustments.
18 As stated earlier in my testimony, the pro forma HTY reflects the average claim
19 payments for the five years ending November 30, 2024. The adjustment resulted in
20 an increase in FTY Injuries and Damages expense of \$230,644 and FPFTY increase
21 of \$268,509.

1 **H. Employee Expenses**

2 **Exhibit 104:** *Schedule 1, Pages 2, 3 and 4, Line 12; Schedule 2, Page 9*

3 **Q. Were adjustments made to Employee Expenses?**

4 A. Yes. Adjustments to the Employee Expense budget were performed based on the HTY
5 non-recoverable expense experience, plus inflation in arriving at a decrease to the FTY
6 Employee Expense budget of \$192,677 and FPFTY budget of \$198,554.

7 **I. Utilities and Company Used Gas**

8 **Exhibit 104:** *Schedule 1, Pages 2, 3 and 4, Line 14; Schedule 2, Page 10*

9 **Q. Please explain the adjustment for Fuel Used in Company Operations.**

10 A. The FTY and FPFTY O&M budget amounts include costs associated with Utilities and
11 Company Used Gas. Like the HTY adjustment, an adjustment to the FTY and FPFTY
12 is necessary to eliminate a representative amount for Utilities and Company Used
13 Gas O&M Expense from the budget to ensure there is no double recovery of the costs.
14 The FTY and FPFTY adjustments were calculated using the HTY adjustment, plus
15 inflation for a reduction of \$487,713 and \$502,588, respectively.

16 **J. Advertising**

17 **Exhibit 104:** *Schedule 1, Pages 2, 3 and 4, Line 15; Schedule 2, Page 11*

18 **Q. Please explain the adjustment for Advertising.**

19 A. The FTY and FPFTY O&M budget amounts are not prepared at a level that identify
20 the specific types of advertising. Because the HTY advertising includes a portion of
21 non-recoverable advertising, adjustments have been made to the budget to include a

representative pro forma level of recoverable advertising. Therefore, the adjustment used to determine the HTY recoverable advertising was also used for the FTY and FPFTY periods by leveraging the HTY adjustment, plus inflation, arriving at reductions to expense of \$192,762 and \$198,641, respectively.

K. NiSource Corporate Services Company “NCSC”

Exhibit 104: *Schedule 1, Pages 2, 3 and 4, Line 20; Schedule 2, Pages 12-14*

Q. Are you sponsoring any ratemaking adjustments to the budgeted NCSC O&M Expense for the FTY and FPFTY?

A. Yes. Exhibit 104, Schedule 2, Page 12 provides a summary of the ratemaking adjustments to Columbia’s NCSC O&M Expense for the FTY and FPFTY.

Adjustments have been made to annualize labor and to remove non-recoverable items for both future periods. Page 13 provides adjustments to annualize labor; the annualization is similar to the adjustments that the Company proposes on Exhibit 104, Schedule 2, Page 1 for Company labor. The FTY adjustment represents an increase of \$208,097 based on HTY annual base salaries and annual merit increases to take effect after November 30, 2024, and charged to O&M Expense based on the HTY labor O&M Expense experience factor for the months December 2024 through February 2025. The adjustment annualizes labor for the months prior to the budgeted annual 3% merit increase to labor, which occurred on March 1, 2025. In a similar fashion, the FPFTY increase of \$151,056 has been adjusted to include a

3% increase on the calculated HTY build-up to FTY annualized labor for the months January 2026 through February 2026.

Page 14 presents adjustments for the removal of various non-recoverable items from the NCSC O&M Expense budget. The non-recoverable adjustments are based upon the HTY adjustments, plus inflation resulting in reductions to the FTY and FPFTY of \$517,482 and \$533,265, respectively.

L. Other Adjustments to Remove Lobbying Expense

Exhibit 104: Schedule 1, Pages 2, 3 and 4, Lines 13 & 17; Schedule 2, Page 15

Q. Please describe the lobbying expense adjustments to Company Memberships, and Materials and Supplies.

A. Adjustments have been made for the removal of a representative level of lobbying expenses included in the Company's budget for Company Memberships, and Materials and Supplies. The FTY and FPFTY adjustments are based upon the HTY level of expense adjusted for inflation resulting in a reduction to expense of \$3,343 and \$3,445, respectively.

M. Rate Case Expense Normalization

Exhibit 104: Schedule 1, Pages 2, 3 and 4, Line 22; Schedule 2, Page 16

Q. Has Columbia included an adjustment to normalize Rate Case Expense for this case?

A. Yes. Exhibit 104, Schedule 2, Page 14 sets forth the Company's claim for Rate Case Expense for this proceeding. The estimated expenses for this rate case reflect costs

1 to be incurred for Columbia's outside consultant witnesses, outside counsel, and
2 incremental costs associated with legal notices, employee expenses and materials &
3 supplies. The total Rate Case Expense included for normalization is \$1,321,000.
4 Columbia proposes to normalize these costs over one year (twelve months).

5 **N. Uncollectible Accounts Expense**

6 (Uncollectible Accounts & Uncollectible Accounts – Unbundled gas)

7 ***Exhibit 104:*** *Schedule 1, Pages 2, 3 and 4, Line 23 & 24; Schedule 2, Page 17*

8 **Q. Please explain the FTY and FPFTY claim for Uncollectible Accounts**
9 **Expense.**

10 A. The HTY normalized Uncollectible Accounts average net write-off rate (representing
11 a three-year average experience of net write-offs as a percentage of billed DIS
12 revenues as developed on Exhibit 4, Schedule 2, Page 24) is applied to the annualized
13 FTY/FPFTY non-CAP DIS revenues, to arrive at Total DIS Uncollectible Accounts
14 Expense for the FTY and FPFTY.

15 **Q. Has Columbia reflected the Unbundling of Uncollectible Expense related**
16 **to gas costs, in other words has Columbia adjusted Uncollectible**
17 **Expense associated with Rider MFC?**

18 A. Yes. Columbia has identified \$1,187,650 in the FPFTY expenses associated with the
19 unbundling of uncollectible related to gas costs that are expected to be collected
20 through Rider MFC. This amount is included in the O&M Expense claim and is offset
21 by the same amount of revenues in Exhibit 103 as developed by Company witness

1 Battig. As a result, the net impact to operating income is zero and does not impact
2 the base rate increase requested in this case.

3 **O. Amortization of Deferred COVID-19 Uncollectible Expense**

4 ***Exhibit 104:*** *Schedule 1, Pages 2, 3 and 4, Line 25; Schedule 2, Page 18*

5 **Q. Please describe the ratemaking adjustment for COVID-19 Uncollectible**
6 **Expense Amortization.**

7 A. The Final Order approving the Settlement of Columbia's base rate case at Docket No.
8 R-2022-3031211 permits Columbia to recover the deferral of COVID-19 Uncollectible
9 Expense of \$2,832,363 over a four-year period starting January 1, 2023, ending in
10 2026. Exhibit 104, Schedule 2, Page 18 shows that no adjustment is required as the
11 FTY and FPFTY as the budget reflects the annual level of amortization expense of
12 \$708,091.

13 **P. Rider USP and Rider EE Costs**

14 ***Exhibit 104:*** *Schedule 1, Pages 2, 3 and 4, Lines 26 & 27; Schedule 2, Page 19*

15 **Q. Please explain the test year adjustments.**

16 A. The adjustments reflected in Exhibit 104 are a result of the matching of expenses to
17 revenue, as Rider USP and Rider EE are fully reconciled mechanisms. As calculated
18 in Exhibit 103 and supported by Company witness Battig, Rider USP and Rider EE
19 revenues for the FTY at present rates is \$31,769,765 and \$1,232,368, respectively,
20 and \$31,845,162 and \$1,235,293 for the FPFTY. As a result, the Rider USP and Rider
21 EE net impact to operating income is zero, with the expense offsetting present rate

1 revenues. Therefore, Rider USP and Rider EE costs do not impact the base rate
2 increase requested in this case.

3 **VI. Universal Services Operating Expense Recovery Proposal**

4 **Q. Is the Company proposing to change the recovery of Rider USP**
5 **Operating Expenses associated with the Company's Energy Assistance**
6 **Team ("EAT")?**

7 A. Yes, please see the Direct Testimony of Columbia witness Davis for more detail about
8 the Company's proposal to move Universal Services Operating Expense recovery
9 related to the Company's EAT from base rates to Rider USP.

10 **Q. Have you quantified the TME December 2026 FPFTY Operating**
11 **Expenses associated with the Company's Energy Assistance Team?**

12 A. Yes, please see CONFIDENTIAL Exhibit JV-1 for the calculated FPFTY (TME
13 December 2026) estimate for the Company's EAT labor and benefits O&M and
14 payroll tax expense totaling \$225,136.

15 **Q. Are the Company's EAT FPFTY Operating Expenses included in**
16 **Columbia's base rate revenue requirement in this proceeding? If yes,**
17 **please explain how the Company will adjust its base rates to transition**
18 **the cost recovery to Rider USP.**

19 A. Yes, currently the Company's EAT FPFTY Operating Expenses are included in the
20 Columbia's base rate revenue requirement. If approved, the Company's requested
21 revenue deficiency in this proceeding will be reduced by \$225,136. Concurrently with

1 the implementation of new base rates in this case, the Company would begin to defer
2 the EAT Operating Expenses to the Rider USP Regulatory Asset for recovery in the
3 Rider USP rates in the next annual filing. The Company's proposal ensures no double
4 recovery of the costs, as the accounting deferral transition would begin concurrently
5 with the reduction to new base rates.

6 **Q. Does this complete your prepared Direct Testimony?**

7 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
Columbia Gas of Pennsylvania, Inc.	)	

**DIRECT TESTIMONY OF
JOHN J. SPANOS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.**

March 20, 2025

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

2 A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill,
3 Pennsylvania.

4 **Q. With what firm are you associated and in what capacity?**

5 A. I am associated with the firm of Gannett Fleming Valuation and Rate
6 Consultants, LLC (Gannett Fleming) as President.

7 **Q. How long have you been associated with Gannett Fleming?**

8 A. I have been associated with the firm since June 1986.

9 **Q. What is your educational background?**

10 A. I have Bachelor of Science degrees in Industrial Management and Mathematics
11 from Carnegie-Mellon University and a Master of Business Administration
12 from York College of Pennsylvania.

13 **Q. Are you a member of any professional societies?**

14 A. Yes. I am a member and past President of the Society of Depreciation
15 Professionals. I am also a member of the American Gas Association/Edison
16 Electric Institute Industry Accounting Committee.

17 **Q. Have you taken the certification examination for depreciation
18 professionals?**

19 A. Yes, I passed the certification examination of the Society of Depreciation
20 Professionals in September 1997 and was recertified in August 2003, February
21 2008, January 2013, February 2018 and February 2023.

22

1 **Q. Will you outline your experience in the field of depreciation?**

2 A. I have over 38 years of depreciation experience which includes expert testimony
3 in more than 480 cases before approximately 46 regulatory commissions,
4 including this Commission. These cases have included depreciation studies in
5 the electric, gas, water, wastewater and pipeline industries. In addition to cases
6 where I have submitted testimony, I have also supervised over 900 other
7 depreciation or valuation assignments. Please refer to Appendix A for my
8 qualifications statement, which includes further information with respect to my
9 work history, case experience, and leadership in the Society of Depreciation
10 Professionals.

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

12 A. My testimony is in support of the depreciation studies conducted under my
13 direction and supervision for the gas plant of Columbia Gas of Pennsylvania,
14 Inc. (“Columbia” or the “Company”).

15 **Q. Have you prepared exhibits presenting the results of your studies?**

16 A. Yes. Exhibit No. 9 presents the results of the depreciation study as of
17 November 30, 2024. Exhibit No. 109, Schedule No. 1, Attachment A presents
18 the results of the depreciation study as of November 30, 2025. Exhibit No. 109,
19 Schedule No. 1, Attachment B presents the results of the depreciation study as
20 of December 31, 2026. In addition, I am responsible for the responses to the
21 following filing requirements pertaining to depreciation under Section
22 53.53(a)(1) of the Commission’s regulations: 3, 4, 5, 6, 7 and 17. I also sponsor
23 Exhibit No. 5 and Exhibit No. 105, which are summaries of the results to
24 Exhibit No. 9 and Exhibit No. 109, respectively.

1 **Q. Please describe Exhibit Nos. 9 and 109.**

2 A. Exhibit No. 9, Schedule No. 1, titled "2024 Depreciation Study - Calculated
3 Annual Depreciation Accruals Related to Gas Plant as of November 30, 2024,"
4 includes the results of the depreciation study as related to the original cost as of
5 November 30, 2024. The report also includes the detailed depreciation
6 calculations. Exhibit No. 109, Schedule No. 1, Attachment A, titled "2025
7 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas
8 Plant as of November 30, 2025," includes the results of the depreciation study
9 as related to the estimated original cost as of November 30, 2025. The report
10 also includes explanatory text, statistics related to the estimation of service life,
11 and the detailed depreciation calculations. Exhibit No. 109, Schedule No. 1,
12 Attachment B, titled "2026 Depreciation Study - Calculated Annual
13 Depreciation Accruals Related to Gas Plant as of December 31, 2026," includes
14 the results of the depreciation study as related to the estimated original cost as
15 of December 31, 2026.

16 **Q. What were the purposes of your depreciation studies?**

17 A. The purposes of the depreciation studies were to estimate the annual
18 depreciation accruals related to gas plant in service for ratemaking purposes
19 and, using Commission-approved procedures, to estimate the Company's book
20 reserve as of November 30, 2025, and December 31, 2026.

21 **Q. Is the Company's claim for annual depreciation in the current**
22 **proceeding based on the same methods of depreciation as were used**
23 **in its most recent Annual Depreciation Report including service life**
24 **study filed in August 2022?**

1 A. Yes, it is. For most plant accounts, the current claim for annual depreciation is
2 based on the straight line remaining life method of depreciation, which has
3 been used for over thirty years. For Accounts 391.1, 391.11, 391.12, 392, 394,
4 395 and 398, the claim is based on the straight line remaining life method of
5 amortization. The accounts have a large number of units, but small asset values
6 representing less than 1 percent of the depreciable plant. The assets represent
7 items located in office buildings, service centers, garages and warehouses.
8 Given the difficulty in maintaining accounting records for these numerous
9 assets and high cost for periodic inventories, retirements are recorded when a
10 vintage is fully amortized, rather than as the units are removed from service.
11 All units are retired when the age of the vintage reaches the amortization
12 period. The annual amortization is based on amortization accounting which
13 distributes the unrecovered cost of fixed capital assets over the remaining
14 amortization period selected for each account.

15 **Q. What group procedure is being used in this proceeding for**
16 **depreciable accounts?**

17 A. The average service life procedure is used in the current proceeding for plant
18 installed prior to 1976 and the equal life group procedure for 1976 and
19 subsequent vintages. This calculation has been used in the same manner as the
20 Company's most recent annual depreciation reports and rate cases as well as for
21 the prior forty years.

22 **Q. Is the Company's claim for accrued depreciation in the current**
23 **proceeding made on the same basis as has been used for over thirty**
24 **years?**

1 A. Yes. The current claim for accrued depreciation is the book reserve brought
2 forward from the book reserve approved by the Commission in the last
3 proceeding.

4 **Q. How was the book reserve used in the calculation of annual**
5 **depreciation?**

6 A. The book reserve by account was allocated to vintages to determine original
7 cost less accrued depreciation by vintage. The total annual accrual is the sum of
8 the results of dividing the original costs less accrued depreciation by the vintage
9 composite remaining lives.

10 **Q. How was the book reserve as of November 30, 2025 estimated?**

11 A. The book reserve as of November 30, 2025, by account, was projected by
12 adding estimated accruals, salvage and the amortization of net salvage, and
13 subtracting estimated retirements and cost of removal from the book reserve as
14 of November 30, 2024. Annual accruals were estimated using the annual
15 accruals calculated as of November 30, 2024. For most accounts, salvage and
16 cost of removal were estimated by (1) expressing actual salvage and cost of
17 removal as a percent of retirements by account, for the most recent five-year
18 period, and (2) applying those percents to the projected retirements by account.
19 For the purpose of calculating the annual accruals, the projected book reserve
20 by account was allocated to vintages based on calculated accrued depreciation
21 as of November 30, 2025.

22 **Q. Was the book reserve as of December 31, 2026 estimated using the**
23 **same methodology?**

24 A. Yes.

1 **Q. Has a service life study of the Company's gas utility property been**
2 **performed?**

3 A. Yes. The most recent service life study was performed as of December 2021.
4 The service life study is the basis for the service lives I used to calculate annual
5 accruals. Service life studies are required in Pennsylvania every five years as
6 the next one will be performed in 2027 for data through December 31, 2026.

7 **Q. Briefly outline the procedure used in performing the service life**
8 **study.**

9 A. The service life study consisted of assembling and compiling historical data
10 from the records related to the gas utility plant of the Company; statistically
11 analyzing such data to obtain historical trends of survivor characteristics;
12 obtaining supplementary information from management and operating
13 personnel concerning Company practices and plans as they relate to plant
14 operations; and interpreting the above data to form judgments of service life
15 characteristics.

16 Iowa type survivor curves were used to describe the estimated survivor
17 characteristics of the mass property groups. Individual service lives were used
18 for major individual units of plant, such as distribution buildings housing
19 offices and shops. The life span concept was recognized by coordinating the
20 lives of associated plant installed in subsequent years with the probable
21 retirement date defined by the life estimated for the major unit.

22 **Q. What statistical data were employed in the historical analyses**
23 **performed for the purpose of estimating service life characteristics?**

1 A. The data consisted of the entries made to record retirements and other
2 transactions related to the gas plant during the period 1939-2021. The year
3 1939 is the first year continuing property records were maintained. These
4 entries were classified by depreciable group, type of transaction, the year in
5 which the transaction took place, and the year in which the plant was installed.
6 Types of transactions included in the data were plant additions, retirements,
7 transfers, and balances. In the presentation of service life statistics, only the
8 significant exposure points that were utilized in determining survivor curves
9 were plotted. This process is utilized to show my judgment in service life
10 determinations.

11 **Q. What was the source of these data?**

12 A. They were assembled from Company records related to its gas plant in service.

13 **Q. Were the methods used in the service life study the same as those**
14 **used in other depreciation studies for gas utility plant presented**
15 **before this Commission?**

16 A. Yes. The methods are the same ones that have been presented previously for
17 Columbia Gas of Pennsylvania, Inc. and for other gas companies before the
18 Pennsylvania Public Utility Commission and that have been accepted by the
19 Commission in its past orders concerning gas utilities.

20 **Q. What approach did you use to estimate the lives of significant**
21 **structures such as office buildings and service centers?**

22 A. I used the life span technique to estimate the lives of significant structures. In
23 this technique, the survivor characteristics of the structures are described by
24 the use of interim survivor curves and estimated probable retirement dates.

1 The interim survivor curve describes the rate of retirement related to the
2 replacement of elements of the structure such as plumbing, heating, doors,
3 windows, roofs, etc. that occur during the life of the facility. The probable
4 retirement date provides the rate of final retirement for each year of installation
5 for the structure by truncating the interim survivor curve for each installation
6 year at its attained age at the date of probable retirement. The use of interim
7 survivor curves truncated at the date of probable retirement provides a
8 consistent method for estimating the lives of the several years of installation
9 inasmuch as concurrent retirement of all years of installation will occur when
10 the structure is retired.

11 **Q. Has your firm used this approach in other proceedings before this**
12 **Commission?**

13 A. Yes, we have used the life span technique on many occasions before the
14 Pennsylvania Public Utility Commission.

15 **Q. What are the bases for the probable retirement years that you have**
16 **estimated for each structure?**

17 A. The bases for the estimates of probable retirement years are life spans for each
18 structure that are based on judgment and incorporate consideration of the age,
19 use, size, nature of construction, management outlook and typical life spans
20 experienced and used by other gas utilities for similar structures. Most of the
21 life spans result in probable retirement dates that are many years in the future.
22 As a result, the retirement of these structures is not yet subject to specific
23 management plans. Such plans would be premature. At the appropriate time,
24 studies of the economics of rehabilitation and continued use or retirement of

1 the structure will be analyzed and the results incorporated in the estimation of
2 the structure's life span.

3 **Q. Are the factors considered in your estimates of service life presented**
4 **in Exhibit No. 109, Schedule No. 1, Attachment A?**

5 A. Yes. A discussion of the factors considered in the estimation of service lives is
6 presented by account on pages III-2 through III-6 of Exhibit No. 109, Schedule
7 No. 1, Attachment A.

8 **Q. Were there any material changes to life characteristics as a result of**
9 **this rate proceeding?**

10 A. No. There was no material change in the life estimate for plant accounts or
11 subaccounts in this rate proceeding. All life estimates were based on the recent
12 annual depreciation report and the service life study as conducted.

13 **Q. Were there any changes to specific plans for an asset class?**

14 A. The assets at the Blackhawk storage facility are planned to be retired by
15 December 31, 2025, however, if there is a delay in the retirement or sale of the
16 facility then some new compressor assets will need to be added. Therefore, the
17 existing assets will be recovered by end of 2025 and the new assets added will
18 have a recovery period of 5 years.

19 **Q. Please outline the contents of Exhibit No. 109, Schedule No. 1,**
20 **Attachment A.**

21 A. Exhibit No. 109, Schedule No. 1, Attachment A is presented in eight parts. Part
22 I, Introduction, sets forth the scope and basis of the study. Part II, Estimation
23 of Survivor Curves, includes a description of the Iowa Curves and the
24 formulation of the retirement rate method. Part III, Service Life

1 Considerations, and Part IV, Calculation of Annual and Accrued Depreciation,
2 include a description of the judgment utilized for life parameters and the
3 explanation of depreciation procedures.

4 Part V, Results of Study, presents a description of the results and
5 summaries of the depreciation calculations. Part VI, Service Life Statistics,
6 presents the graphs and tables which relate to the service life study. Part VII,
7 Detailed Depreciation Calculations, sets forth the detailed depreciation
8 calculations by account. Part VIII, Experienced Net Salvage, presents the cost
9 of removal and gross salvage by account for the years 2020 through 2024.

10 Table 1, pages V-4 through V-6 presents the estimated survivor curve,
11 the original cost as of November 30, 2025, and the book reserve and calculated
12 annual depreciation for each account or subaccount of Gas Plant. Table 2 on
13 page V-7 presents the bringforward to November 30, 2025, of the book
14 depreciation reserve as of November 30, 2024. Table 3 on pages V-8 and V-9
15 sets forth the calculation of the annual accruals used in the bringforward. Table
16 4, page V-10, presents the experienced net salvage during the five-year period,
17 2020 through 2024.

18 The section beginning on page VI-1 presents the results of the retirement
19 rate analyses prepared as the historical bases for the service life estimates. The
20 section beginning on page VII-1 presents the depreciation calculations related
21 to original cost. The tabulation on pages VII-3 through VII-6 presents the
22 cumulative depreciated original cost by year installed. The tabulations on pages
23 VII-8 through VII-70 present the calculation of annual depreciation by vintage
24 by account for each depreciable group of utility plant.

1 **Q. Please outline the contents of Exhibit No. 109, Schedule No. 1,**
2 **Attachment B.**

3 A. Exhibit No. 109, Schedule No. 1, Attachment B includes a description of the
4 results, summaries of the depreciation calculations, and the detailed
5 depreciation calculations as of December 31, 2026. The descriptions and
6 explanations presented in Exhibit No. 109, Schedule No. 1, Attachment A are
7 also applicable to the depreciation calculations presented in Exhibit No. 109,
8 Schedule No. 1, Attachment B. The graphs and tables related to service life
9 presented in Exhibit No. 109, Schedule No. 1, Attachment A also support the
10 service life estimates used in Exhibit No. 109, Schedule No. 1, Attachment B
11 inasmuch as the estimates are the same for both test years. The summary
12 tables and detailed depreciation calculations as of December 31, 2026, are
13 organized and presented in the same manner as those as of November 30,
14 2025.

15 **Q. Please outline the contents of Exhibit No. 9.**

16 A. Exhibit No. 9 includes a description of the results, summaries of the
17 depreciation calculations, and the detailed depreciation calculations as of
18 November 30, 2024. The descriptions and explanations presented in Exhibit
19 No. 109, Schedule No. 1, Attachment A are also applicable to the depreciation
20 calculations presented in Exhibit No. 9. The graphs and tables related to
21 service life presented in Exhibit No. 109, Schedule No. 1, Attachment A also
22 support the service life estimates used in Exhibit No. 9, inasmuch as the
23 estimates are the same for both test years. The summary tables and detailed

1 depreciation calculations as of November 30, 2024, are organized and
2 presented in the same manner as those as of November 30, 2025.

3 **Q. Please use an example to illustrate the manner in which the study is**
4 **presented in Exhibit Nos. 9, and 109.**

5 A. I will use Account 376, Mains, as my example, inasmuch as it is the largest
6 depreciable group and represents 70 percent of the original cost of depreciable
7 gas plant as of November 30, 2025.

8 The retirement rate method was used to analyze the survivor
9 characteristics of this group. The life tables for the 1939-2021 and 1982-2021
10 experience bands are presented on pages VI-48 through VI-55 of Exhibit No.
11 109, Schedule No. 1, Attachment A. The life tables, or original survivor curve,
12 are plotted along with the estimated smooth survivor curve, the 65-R1, on page
13 VI-47.

14 The calculations of the annual depreciation related to the original cost as
15 of November 30, 2024, of gas plant are presented by type main on pages II-33
16 through II-37 of Exhibit No. 9. The calculation is based on the 65-R1 survivor
17 curve, the attained age, and the allocated book reserve. The calculations as of
18 November 30, 2025, are presented by type main on pages VII-34 through VII-
19 37 of Exhibit No. 109, Schedule No. 1, Attachment A and are based in part on
20 the bringforward of the book reserve. Also, the calculations as of December 31,
21 2026, are presented by type main on pages II-34 through II-36 of Exhibit No.
22 109, Schedule No. 1, Attachment B and are based in part on the bringforward of
23 the book reserve. The tabulations in Exhibit Nos. 9 and 109 set forth the
24 installation year, the original cost, calculated accrued depreciation, allocated

1 book reserve, future accruals, remaining life and annual accrual. The totals are
2 brought forward to Table 1 on page I-3 in Exhibit No. 9, page V-4 in Exhibit No.
3 109, Schedule No. 1, Attachment A and on page I-3 in Exhibit No. 109, Schedule
4 No. 1, Attachment B.

5 **Q. In what manner is net salvage incorporated in the depreciation**
6 **calculations?**

7 A. As stated on page IV-9 of Exhibit No. 109, Schedule No. 1, Attachment A, no
8 adjustment for net salvage was made to the calculated annual depreciation
9 amounts. The total calculated annual depreciation set forth on page I-6 of
10 Exhibit No. 9, page V-10 of Exhibit No. 109, Schedule No. 1, Attachment A and
11 on page I-9 of Exhibit No. 109, Schedule No. 1, Attachment B should include an
12 addition for the amortization of negative net salvage in accordance with the
13 practice of this Commission. The amortization is based on experience during
14 the period 2019 through 2023 for the calculation as of November 30, 2024, and
15 on experience during the period 2020 through 2024 for the calculation as of
16 November 30, 2025.

17 The amortization for the December 31, 2026, calculation is based on
18 experience during the period 2020 through December 31, 2024, plus estimates
19 for the period January 2025 through December 2025. The amounts of the five-
20 year amortizations are calculated in Table 2 on page I-6 of Exhibit No. 9, in
21 Table 4 on page V-10 of Exhibit No. 109, Schedule No. 1, Attachment A and in
22 Table 4 on page I-9 of Exhibit No. 109, Schedule No. 1, Attachment B.

23 **Q. Have you provided a monthly bringforward to December 31, 2026,**
24 **of the plant and book depreciation reserve as of November 30, 2025**

1 A. Yes, Exhibit JJS-001 at the end of this testimony provides the monthly detail of
2 the plant in service, book depreciation reserve and the calculated depreciation.
3 This exhibit agrees with the fully projected future test year plant and reserve
4 balances as shown on Exhibit No. 109, Schedule No. 1, Attachment B, Table 1 on
5 pages I-3 through I-5.

6 **Q. Does this complete your testimony at this time?**

7 A. Yes, it does.

APPENDIX A

JOHN SPANOS

DEPRECIATION EXPERIENCE

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008, January 2013, February 2018 and February 2023.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 through December 1995, I helped prepare numerous depreciation and original cost studies for utility companies in various industries. I helped perform depreciation studies for the following telephone companies: United Telephone of Pennsylvania, United Telephone of New Jersey, and Anchorage Telephone Utility. I helped perform depreciation studies for the following

companies in the railroad industry: Union Pacific Railroad, Burlington Northern Railroad, and Wisconsin Central Transportation Corporation.

I helped perform depreciation studies for the following organizations in the electric utility industry: Chugach Electric Association, The Cincinnati Gas and Electric Company (CG&E), The Union Light, Heat and Power Company (ULH&P), Northwest Territories Power Corporation, and the City of Calgary - Electric System.

I helped perform depreciation studies for the following pipeline companies: TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

I helped perform depreciation studies for the following gas utility companies: Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, CG&E, ULH&P, Lawrenceburg Gas Company and Penn Fuel Gas, Inc.

I helped perform depreciation studies for the following water utility companies: Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

In each of the above studies, I assembled and analyzed historical and simulated data, performed field reviews, developed preliminary estimates of service life and net salvage, calculated annual depreciation, and prepared reports for submission to state public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and

Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc., in April 2012, I was promoted to the position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC) and in January of 2019, I was promoted to my present position of President of Gannett Fleming Valuation and Rate Consultants, LLC. In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Iowa-American Water Company; New Jersey-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company;

Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Aqua Illinois, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Duke Energy Progress; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Maryland-American Water Company; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company;

Black Hills Power; Black Hills Colorado Gas; Black Hills Energy Arkansas, Inc.; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation; Greater Missouri Operations; Tennessee Valley Authority; Omaha Public Power District; Indianapolis Power & Light Company; Vermont Gas Systems, Inc.; Metropolitan Edison; Pennsylvania Electric; West Penn Power; Pennsylvania Power; PHI Service Company - Delmarva Power and Light; Atmos Energy Corporation; Citizens Energy Group; PSE&G Company; Berkshire Gas Company; Alabama Gas Corporation; Mid-Atlantic Interstate Transmission, LLC; SUEZ Water; WEC Energy Group; Rocky Mountain Natural Gas, LLC; Illinois-American Water Company; Northern Illinois Gas Company; Public Service of New Hampshire; FirstEnergy Service Corporation; Northeast Ohio Natural Gas Corporation; Blue Granite Water Company; Spire Missouri, Inc.; Dominion Energy South Carolina, Inc.; South FirstEnergy Operating Companies; Dayton Power and Light Company; Liberty Utilities; East Kentucky Power Cooperative; Bangor Natural Gas; Hanover Borough Municipal Water Works; West Virginia American Water Company; Evergy Metro; Evergy Missouri West; Granite State Electric; Bluegrass Water; The Borough of Ambler; Newtown Artesian Water Company and Connecticut Water Company.

My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. Have you submitted testimony to any state utility commission on the subject of utility plant depreciation?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission; the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission (“FERC”); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; the Public Service Commission of West Virginia; Maine Public Utility Commission; Iowa Utility Board; Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission; Commonwealth of Massachusetts Department of Public Utilities; Rhode Island Public Utilities Commission and the North Carolina Utilities Commission.

Q. Have you had any additional education relating to utility plant depreciation?

A. Yes. I have completed the following courses conducted by Depreciation Programs, Inc.:
“Techniques of Life Analysis,” “Techniques of Salvage and Depreciation Analysis,”
“Forecasting Life and Salvage,” “Modeling and Life Analysis Using Simulation,” and
“Managing a Depreciation Study.” I have also completed the “Introduction to Public
Utility Accounting” program conducted by the American Gas Association.

Q. Does this conclude your qualification statement?

A. Yes.

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY

	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
01.	1998	PA PUC	R-00984375	City of Bethlehem – Bureau of Water	Original Cost and Depreciation
02.	1998	PA PUC	R-00984567	City of Lancaster	Original Cost and Depreciation
03.	1999	PA PUC	R-00994605	The York Water Company	Depreciation
04.	2000	D.T.&E.	DTE 00-105	Massachusetts-American Water Company	Depreciation
05.	2001	PA PUC	R-00016114	City of Lancaster	Original Cost and Depreciation
06.	2001	PA PUC	R-00017236	The York Water Company	Depreciation
07.	2001	PA PUC	R-00016339	Pennsylvania-American Water Company	Depreciation
08.	2001	OH PUC	01-1228-GA-AIR	Cinergy Corp – Cincinnati Gas & Elect Company	Depreciation
09.	2001	KY PSC	2001-092	Cinergy Corp – Union Light, Heat & Power Co.	Depreciation
10.	2002	PA PUC	R-00016750	Philadelphia Suburban Water Company	Depreciation
11.	2002	KY PSC	2002-00145	Columbia Gas of Kentucky	Depreciation
12.	2002	NJ BPU	GF02040245	NUI Corporation/Elizabethtown Gas Company	Depreciation
13.	2002	ID PUC	IPC-E-03-7	Idaho Power Company	Depreciation
14.	2003	PA PUC	R-0027975	The York Water Company	Depreciation
15.	2003	IN URC	R-0027975	Cinergy Corp – PSI Energy, Inc.	Depreciation
16.	2003	PA PUC	R-00038304	Pennsylvania-American Water Company	Depreciation
17.	2003	MO PSC	WR-2003-0500	Missouri-American Water Company	Depreciation
18.	2003	FERC	ER03-1274-000	NSTAR-Boston Edison Company	Depreciation
19.	2003	NJ BPU	BPU 03080683	South Jersey Gas Company	Depreciation
20.	2003	NV PUC	03-10001	Nevada Power Company	Depreciation
21.	2003	LA PSC	U-27676	CenterPoint Energy – Arkla	Depreciation
22.	2003	PA PUC	R-00038805	Pennsylvania Suburban Water Company	Depreciation
23.	2004	AB En/Util Bd	1306821	EPCOR Distribution, Inc.	Depreciation
24.	2004	PA PUC	R-00038168	National Fuel Gas Distribution Corp (PA)	Depreciation
25.	2004	PA PUC	R-00049255	PPL Electric Utilities	Depreciation
26.	2004	PA PUC	R-00049165	The York Water Company	Depreciation
27.	2004	OK Corp Cm	PUC 200400187	CenterPoint Energy – Arkla	Depreciation
28.	2004	OH PUC	04-680-EI-AIR	Cinergy Corp. – Cincinnati Gas and Electric Company	Depreciation
29.	2004	RR Com of TX	GUD#	CenterPoint Energy – Entex Gas Services Div.	Depreciation
30.	2004	NY PUC	04-G-1047	National Fuel Gas Distribution Gas (NY)	Depreciation
31.	2004	AR PSC	04-121-U	CenterPoint Energy – Arkla	Depreciation
32.	2005	IL CC	05-ICC-06	North Shore Gas Company	Depreciation
33.	2005	IL CC	05-ICC-06	Peoples Gas Light and Coke Company	Depreciation
34.	2005	KY PSC	2005-00042	Union Light Heat & Power	Depreciation

	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
35.	2005	IL CC	05-0308	MidAmerican Energy Company	Depreciation
36.	2005	MO PSC	GF-2005	Laclede Gas Company	Depreciation
37.	2005	KS CC	05-WSEE-981-RTS	Westar Energy	Depreciation
38.	2005	RR Com of TX	GUD #	CenterPoint Energy – Entex Gas Services Div.	Depreciation
39.	2005	US District Court	Cause No. 1:99-CV-1693-LJM/VSS	Cinergy Corporation	Accounting
40.	2005	OK CC	PUD 200500151	Oklahoma Gas and Electric Company	Depreciation
41.	2005	MA Dept Tele- com & Ergy	DTE 05-85	NSTAR	Depreciation
42.	2005	NY PUC	05-E-934/05-G-0935	Central Hudson Gas & Electric Company	Depreciation
43.	2005	AK Reg Com	U-04-102	Chugach Electric Association	Depreciation
44.	2005	CA PUC	A05-12-002	Pacific Gas & Electric	Depreciation
45.	2006	PA PUC	R-00051030	Aqua Pennsylvania, Inc.	Depreciation
46.	2006	PA PUC	R-00051178	T.W. Phillips Gas and Oil Company	Depreciation
47.	2006	NC Util Cm.	G-5, Sub522	Pub. Service Company of North Carolina	Depreciation
48.	2006	PA PUC	R-00051167	City of Lancaster	Depreciation
49.	2006	PA PUC	R00061346	Duquesne Light Company	Depreciation
50.	2006	PA PUC	R-00061322	The York Water Company	Depreciation
51.	2006	PA PUC	R-00051298	PPL GAS Utilities	Depreciation
52.	2006	PUC of TX	32093	CenterPoint Energy – Houston Electric	Depreciation
53.	2006	KY PSC	2006-00172	Duke Energy Kentucky	Depreciation
54.	2006	SC PSC		SCANA	Accounting
55.	2006	AK Reg Com	U-06-6	Municipal Light and Power	Depreciation
56.	2006	DE PSC	06-284	Delmarva Power and Light	Depreciation
57.	2006	IN URC	IURC43081	Indiana American Water Company	Depreciation
58.	2006	AK Reg Com	U-06-134	Chugach Electric Association	Depreciation
59.	2006	MO PSC	WR-2007-0216	Missouri American Water Company	Depreciation
60.	2006	FERC	IS05-82-002, et al	TransAlaska Pipeline	Depreciation
61.	2006	PA PUC	R-00061493	National Fuel Gas Distribution Corp. (PA)	Depreciation
62.	2007	NC Util Com.	E-7 SUB 828	Duke Energy Carolinas, LLC	Depreciation
63.	2007	OH PSC	08-709-EL-AIR	Duke Energy Ohio Gas	Depreciation
64.	2007	PA PUC	R-00072155	PPL Electric Utilities Corporation	Depreciation
65.	2007	KY PSC	2007-00143	Kentucky American Water Company	Depreciation

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66.	2007	PA PUC	R-00072229	Pennsylvania American Water Company	Depreciation
67.	2007	KY PSC	2007-0008	NiSource – Columbia Gas of Kentucky	Depreciation
68.	2007	NY PSC	07-G-0141	National Fuel Gas Distribution Corp (NY)	Depreciation
69.	2008	AK PSC	U-08-004	Anchorage Water & Wastewater Utility	Depreciation
70.	2008	TN Reg Auth	08-00039	Tennessee-American Water Company	Depreciation
71.	2008	DE PSC	08-96	Artesian Water Company	Depreciation
72.	2008	PA PUC	R-2008-2023067	The York Water Company	Depreciation
73.	2008	KS CC	08-WSEE1-RTS	Westar Energy	Depreciation
74.	2008	IN URC	43526	Northern Indiana Public Service Company	Depreciation
75.	2008	IN URC	43501	Duke Energy Indiana	Depreciation
76.	2008	MD PSC	9159	NiSource – Columbia Gas of Maryland	Depreciation
77.	2008	KY PSC	2008-000251	Kentucky Utilities	Depreciation
78.	2008	KY PSC	2008-000252	Louisville Gas & Electric	Depreciation
79.	2008	PA PUC	2008-20322689	Pennsylvania American Water Co. - Wastewater	Depreciation
80.	2008	NY PSC	08-E887/08-00888	Central Hudson	Depreciation
81.	2008	WV TC	VE-080416/VG-8080417	Avista Corporation	Depreciation
82.	2008	IL CC	ICC-09-166	Peoples Gas, Light and Coke Company	Depreciation
83.	2009	IL CC	ICC-09-167	North Shore Gas Company	Depreciation
84.	2009	DC PSC	1076	Potomac Electric Power Company	Depreciation
85.	2009	KY PSC	2009-00141	NiSource – Columbia Gas of Kentucky	Depreciation
86.	2009	FERC	ER08-1056-002	Entergy Services	Depreciation
87.	2009	PA PUC	R-2009-2097323	Pennsylvania American Water Company	Depreciation
88.	2009	NC Util Cm	E-7, Sub 090	Duke Energy Carolinas, LLC	Depreciation
89.	2009	KY PSC	2009-00202	Duke Energy Kentucky	Depreciation
90.	2009	VA St. CC	PUE-2009-00059	Aqua Virginia, Inc.	Depreciation
91.	2009	PA PUC	2009-2132019	Aqua Pennsylvania, Inc.	Depreciation
92.	2009	MS PSC	Docket No. 2011-UA-183	Entergy Mississippi	Depreciation
93.	2009	AK PSC	09-08-U	Entergy Arkansas	Depreciation
94.	2009	TX PUC	37744	Entergy Texas	Depreciation
95.	2009	TX PUC	37690	El Paso Electric Company	Depreciation
96.	2009	PA PUC	R-2009-2106908	The Borough of Hanover	Depreciation
97.	2009	KS CC	10-KCPE-415-RTS	Kansas City Power & Light	Depreciation
98.	2009	PA PUC	R-2009-	United Water Pennsylvania	Depreciation

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99.	2009	OH PUC		Aqua Ohio Water Company	Depreciation
100.	2009	WI PSC	3270-DU-103	Madison Gas & Electric Company	Depreciation
101.	2009	MO PSC	WR-2010	Missouri American Water Company	Depreciation
102.	2009	AK Reg Cm	U-09-097	Chugach Electric Association	Depreciation
103.	2010	IN URC	43969	Northern Indiana Public Service Company	Depreciation
104.	2010	WI PSC	6690-DU-104	Wisconsin Public Service Corp.	Depreciation
105.	2010	PA PUC	R-2010-2161694	PPL Electric Utilities Corp.	Depreciation
106.	2010	KY PSC	2010-00036	Kentucky American Water Company	Depreciation
107.	2010	PA PUC	R-2009-2149262	Columbia Gas of Pennsylvania	Depreciation
108.	2010	MO PSC	GR-2010-0171	Laclede Gas Company	Depreciation
109.	2010	SC PSC	2009-489-E	South Carolina Electric & Gas Company	Depreciation
110.	2010	NJ BD OF PU	ER09080664	Atlantic City Electric	Depreciation
111.	2010	VA St. CC	PUE-2010-00001	Virginia American Water Company	Depreciation
112.	2010	PA PUC	R-2010-2157140	The York Water Company	Depreciation
113.	2010	MO PSC	ER-2010-0356	Greater Missouri Operations Company	Depreciation
114.	2010	MO PSC	ER-2010-0355	Kansas City Power and Light	Depreciation
115.	2010	PA PUC	R-2010-2167797	T.W. Phillips Gas and Oil Company	Depreciation
116.	2010	PSC SC	2009-489-E	SCANA – Electric	Depreciation
117.	2010	PA PUC	R-2010-22010702	Peoples Natural Gas, LLC	Depreciation
118.	2010	AK PSC	10-067-U	Oklahoma Gas and Electric Company	Depreciation
119.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Company - NIFL	Depreciation
120.	2010	IN URC	Cause No. 43894	Northern Indiana Public Serv. Co. - Kokomo	Depreciation
121.	2010	PA PUC	R-2010-2166212	Pennsylvania American Water Co. - WW	Depreciation
122.	2010	NC Util Cn.	W-218,SUB310	Aqua North Carolina, Inc.	Depreciation
123.	2011	OH PUC	11-4161-WS-AIR	Ohio American Water Company	Depreciation
124.	2011	MS PSC	EC-123-0082-00	Entergy Mississippi	Depreciation
125.	2011	CO PUC	11AL-387E	Black Hills Colorado	Depreciation
126.	2011	PA PUC	R-2010-2215623	Columbia Gas of Pennsylvania	Depreciation
127.	2011	PA PUC	R-2010-2179103	City of Lancaster – Bureau of Water	Depreciation
128.	2011	IN URC	43114 IGCC 4S	Duke Energy Indiana	Depreciation
129.	2011	FERC	IS11-146-000	Enbridge Pipelines (Southern Lights)	Depreciation
130.	2011	IL CC	11-0217	MidAmerican Energy Corporation	Depreciation
131.	2011	OK CC	201100087	Oklahoma Gas & Electric Company	Depreciation
132.	2011	PA PUC	2011-2232243	Pennsylvania American Water Company	Depreciation

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133.	2011	FERC	RP11-___-000	Carolina Gas Transmission	Depreciation
134.	2012	WA UTC	UE-120436/UG-120437	Avista Corporation	Depreciation
135.	2012	AK Reg Cm	U-12-009	Chugach Electric Association	Depreciation
136.	2012	MA PUC	DPU 12-25	Columbia Gas of Massachusetts	Depreciation
137.	2012	TX PUC	40094	El Paso Electric Company	Depreciation
138.	2012	ID PUC	IPC-E-12	Idaho Power Company	Depreciation
139.	2012	PA PUC	R-2012-2290597	PPL Electric Utilities	Depreciation
140.	2012	PA PUC	R-2012-2311725	Borough of Hanover – Bureau of Water	Depreciation
141.	2012	KY PSC	2012-00222	Louisville Gas and Electric Company	Depreciation
142.	2012	KY PSC	2012-00221	Kentucky Utilities Company	Depreciation
143.	2012	PA PUC	R-2012-2285985	Peoples Natural Gas Company	Depreciation
144.	2012	DC PSC	Case 1087	Potomac Electric Power Company	Depreciation
145.	2012	OH PSC	12-1682-EL-AIR	Duke Energy Ohio (Electric)	Depreciation
146.	2012	OH PSC	12-1685-GA-AIR	Duke Energy Ohio (Gas)	Depreciation
147.	2012	PA PUC	R-2012-2310366	City of Lancaster – Sewer Fund	Depreciation
148.	2012	PA PUC	R-2012-2321748	Columbia Gas of Pennsylvania	Depreciation
149.	2012	FERC	ER-12-2681-000	ITC Holdings	Depreciation
150.	2012	MO PSC	ER-2012-0174	Kansas City Power and Light	Depreciation
151.	2012	MO PSC	ER-2012-0175	KCPL Greater Missouri Operations Company	Depreciation
152.	2012	MO PSC	GO-2012-0363	Laclede Gas Company	Depreciation
153.	2012	MN PUC	G007,001/D-12-533	Integrlys – MN Energy Resource Group	Depreciation
154.	2012	TX PUC	SOAH 582-14-1051/ TECQ 2013-2007-UCR	Aqua Texas	Depreciation
155.	2012	PA PUC	2012-2336379	York Water Company	Depreciation
156.	2013	NJ BPU	ER12121071	PHI Service Company– Atlantic City Electric	Depreciation
157.	2013	KY PSC	2013-00167	Columbia Gas of Kentucky	Depreciation
158.	2013	VA St CC	2013-00020	Virginia Electric and Power Company	Depreciation
159.	2013	IA Util Bd	2013-0004	MidAmerican Energy Corporation	Depreciation
160.	2013	PA PUC	2013-2355276	Pennsylvania American Water Company	Depreciation
161.	2013	NY PSC	13-E-0030, 13-G-0031, 13-S-0032	Consolidated Edison of New York	Depreciation
162.	2013	PA PUC	2013-2355886	Peoples TWP LLC	Depreciation
163.	2013	TN Reg Auth	12-0504	Tennessee American Water	Depreciation
164.	2013	ME PUC	2013-168	Central Maine Power Company	Depreciation
165.	2013	DC PSC	Case 1103	PHI Service Company – PEPCO	Depreciation

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166.	2013	WY PSC	2003-ER-13	Cheyenne Light, Fuel and Power Company	Depreciation
167.	2013	FERC	ER13-2428-0000	Kentucky Utilities	Depreciation
168.	2013	FERC	ER13- -0000	MidAmerican Energy Company	Depreciation
169.	2013	FERC	ER13-2410-0000	PPL Utilities	Depreciation
170.	2013	PA PUC	R-2013-2372129	Duquesne Light Company	Depreciation
171.	2013	NJ BPU	ER12111052	Jersey Central Power and Light Company	Depreciation
172.	2013	PA PUC	R-2013-2390244	Bethlehem, City of – Bureau of Water	Depreciation
173.	2013	OK CC	UM 1679	Oklahoma, Public Service Company of	Depreciation
174.	2013	IL CC	13-0500	Nicor Gas Company	Depreciation
175.	2013	WY PSC	20000-427-EA-13	PacifiCorp	Depreciation
176.	2013	UT PSC	13-035-02	PacifiCorp	Depreciation
177.	2013	OR PUC	UM 1647	PacifiCorp	Depreciation
178.	2013	PA PUC	2013-2350509	Dubois, City of	Depreciation
179.	2014	IL CC	14-0224	North Shore Gas Company	Depreciation
180.	2014	FERC	ER14- -0000	Duquesne Light Company	Depreciation
181.	2014	SD PUC	EL14-026	Black Hills Power Company	Depreciation
182.	2014	WY PSC	20002-91-ER-14	Black Hills Power Company	Depreciation
183.	2014	PA PUC	2014-2428304	Borough of Hanover – Municipal Water Works	Depreciation
184.	2014	PA PUC	2014-2406274	Columbia Gas of Pennsylvania	Depreciation
185.	2014	IL CC	14-0225	Peoples Gas Light and Coke Company	Depreciation
186.	2014	MO PSC	ER-2014-0258	Ameren Missouri	Depreciation
187.	2014	KS CC	14-BHCG-502-RTS	Black Hills Service Company	Depreciation
188.	2014	KS CC	14-BHCG-502-RTS	Black Hills Utility Holdings	Depreciation
189.	2014	KS CC	14-BHCG-502-RTS	Black Hills Kansas Gas	Depreciation
190.	2014	PA PUC	2014-2418872	Lancaster, City of – Bureau of Water	Depreciation
191.	2014	WV PSC	14-0701-E-D	First Energy – MonPower/PotomacEdison	Depreciation
192.	2014	VA St CC	PUC-2014-00045	Aqua Virginia	Depreciation
193.	2014	VA St CC	PUE-2013	Virginia American Water Company	Depreciation
194.	2014	OK CC	PUD201400229	Oklahoma Gas and Electric Company	Depreciation
195.	2014	OR PUC	UM1679	Portland General Electric	Depreciation
196.	2014	IN URC	Cause No. 44576	Indianapolis Power & Light	Depreciation
197.	2014	MA DPU	DPU. 14-150	NSTAR Gas	Depreciation
198.	2014	CT PURA	14-05-06	Connecticut Light and Power	Depreciation
199.	2014	MO PSC	ER-2014-0370	Kansas City Power & Light	Depreciation

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200.	2014	KY PSC	2014-00371	Kentucky Utilities Company	Depreciation
201.	2014	KY PSC	2014-00372	Louisville Gas and Electric Company	Depreciation
202.	2015	PA PUC	R-2015-2462723	United Water Pennsylvania Inc.	Depreciation
203.	2015	PA PUC	R-2015-2468056	NiSource - Columbia Gas of Pennsylvania	Depreciation
204.	2015	NY PSC	15-E-0283/15-G-0284	New York State Electric and Gas Corporation	Depreciation
205.	2015	NY PSC	15-E-0285/15-G-0286	Rochester Gas and Electric Corporation	Depreciation
206.	2015	MO PSC	WR-2015-0301/SR-2015-0302	Missouri American Water Company	Depreciation
207.	2015	OK CC	PUD 201500208	Oklahoma, Public Service Company of	Depreciation
208.	2015	WV PSC	15-0676-W-42T	West Virginia American Water Company	Depreciation
209.	2015	PA PUC	2015-2469275	PPL Electric Utilities	Depreciation
210.	2015	IN URC	Cause No. 44688	Northern Indiana Public Service Company	Depreciation
211.	2015	OH PSC	14-1929-EL-RDR	First Energy-Ohio Edison/Cleveland Electric/ Toledo Edison	Depreciation
212.	2015	NM PRC	15-00127-UT	El Paso Electric	Depreciation
213.	2015	TX PUC	PUC-44941; SOAH 473-15-5257	El Paso Electric	Depreciation
214.	2015	WI PSC	3270-DU-104	Madison Gas and Electric Company	Depreciation
215.	2015	OK CC	PUD 201500273	Oklahoma Gas and Electric	Depreciation
216.	2015	KY PSC	Doc. No. 2015-00418	Kentucky American Water Company	Depreciation
217.	2015	NC UC	Doc. No. G-5, Sub 565	Public Service Company of North Carolina	Depreciation
218.	2016	WA UTC	Docket UE-17	Puget Sound Energy	Depreciation
219.	2016	NY PSC	Case No. 16-W-0130	SUEZ Water New York, Inc.	Depreciation
220.	2016	MO PSC	ER-2016-0156	KCPL – Greater Missouri	Depreciation
221.	2016	WI PSC		Wisconsin Public Service Corporation	Depreciation
222.	2016	KY PSC	Case No. 2016-00026	Kentucky Utilities Company	Depreciation
223.	2016	KY PSC	Case No. 2016-00027	Louisville Gas and Electric Company	Depreciation
224.	2016	OH PUC	Case No. 16-0907-WW-AIR	Aqua Ohio	Depreciation
225.	2016	MD PSC	Case 9417	NiSource - Columbia Gas of Maryland	Depreciation
226.	2016	KY PSC	2016-00162	Columbia Gas of Kentucky	Depreciation
227.	2016	DE PSC	16-0649	Delmarva Power and Light Company – Electric	Depreciation
228.	2016	DE PSC	16-0650	Delmarva Power and Light Company – Gas	Depreciation
229.	2016	NY PSC	Case 16-G-0257	National Fuel Gas Distribution Corp – NY Div	Depreciation
230.	2016	PA PUC	R-2016-2537349	Metropolitan Edison Company	Depreciation
231.	2016	PA PUC	R-2016-2537352	Pennsylvania Electric Company	Depreciation
232.	2016	PA PUC	R-2016-2537355	Pennsylvania Power Company	Depreciation

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233.	2016	PA PUC	R-2016-2537359	West Penn Power Company	Depreciation
234.	2016	PA PUC	R-2016-2529660	NiSource - Columbia Gas of PA	Depreciation
235.	2016	KY PSC	Case No. 2016-00063	Kentucky Utilities / Louisville Gas & Electric Co	Depreciation
236.	2016	MO PSC	ER-2016-0285	KCPL Missouri	Depreciation
237.	2016	AR PSC	16-052-U	Oklahoma Gas & Electric Co	Depreciation
238.	2016	PSCW	6680-DU-104	Wisconsin Power and Light	Depreciation
239.	2016	ID PUC	IPC-E-16-23	Idaho Power Company	Depreciation
240.	2016	OR PUC	UM1801	Idaho Power Company	Depreciation
241.	2016	ILL CC	16-	MidAmerican Energy Company	Depreciation
242.	2016	KY PSC	Case No. 2016-00370	Kentucky Utilities Company	Depreciation
243.	2016	KY PSC	Case No. 2016-00371	Louisville Gas and Electric Company	Depreciation
244.	2016	IN URC	Cause No. 45029	Indianapolis Power & Light	Depreciation
245.	2016	AL RC	U-16-081	Chugach Electric Association	Depreciation
246.	2017	MA DPU	D.P.U. 17-05	NSTAR Electric Company and Western Massachusetts Electric Company	Depreciation
247.	2017	TX PUC	PUC-26831, SOAH 973-17-2686	El Paso Electric Company	Depreciation
248.	2017	WA UTC	UE-17033 and UG-170034	Puget Sound Energy	Depreciation
249.	2017	OH PUC	Case No. 17-0032-EL-AIR	Duke Energy Ohio	Depreciation
250.	2017	VA SCC	Case No. PUE-2016-00413	Virginia Natural Gas, Inc.	Depreciation
251.	2017	OK CC	Case No. PUD201700151	Public Service Company of Oklahoma	Depreciation
252.	2017	MD PSC	Case No. 9447	Columbia Gas of Maryland	Depreciation
253.	2017	NC UC	Docket No. E-2, Sub 1142	Duke Energy Progress	Depreciation
254.	2017	VA SCC	Case No. PUR-2017-00090	Dominion Virginia Electric and Power Company	Depreciation
255.	2017	FERC	ER17-1162	MidAmerican Energy Company	Depreciation
256.	2017	PA PUC	R-2017-2595853	Pennsylvania American Water Company	Depreciation
257.	2017	OR PUC	UM1809	Portland General Electric	Depreciation
258.	2017	FERC	ER17-217-000	Jersey Central Power & Light	Depreciation
259.	2017	FERC	ER17-211-000	Mid-Atlantic Interstate Transmission, LLC	Depreciation
260.	2017	MN PUC	Docket No. G007/D-17-442	Minnesota Energy Resources Corporation	Depreciation
261.	2017	IL CC	Docket No. 17-0124	Northern Illinois Gas Company	Depreciation
262.	2017	OR PUC	UM1808	Northwest Natural Gas Company	Depreciation
263.	2017	NY PSC	Case No. 17-W-0528	SUEZ Water Owego-Nichols	Depreciation
264.	2017	MO PSC	GR-2017-0215	Laclede Gas Company	Depreciation
265.	2017	MO PSC	GR-2017-0216	Missouri Gas Energy	Depreciation

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266.	2017	ILL CC	Docket No. 17-0337	Illinois-American Water Company	Depreciation
267.	2017	FERC	Docket No. ER18-22-000	PPL Electric Utilities Corporation	Depreciation
268.	2017	IN URC	Cause No. 44988	Northern Indiana Public Service Company	Depreciation
269.	2017	NJ BPU	BPU Docket No. WR17090985	New Jersey American Water Company, Inc.	Depreciation
270.	2017	RI PUC	Docket No. 4800	SUEZ Water Rhode Island	Depreciation
271.	2017	OK CC	Cause No. PUD 201700496	Oklahoma Gas and Electric Company	Depreciation
272.	2017	NJ BPU	ER18010029 & GR18010030	Public Service Electric and Gas Company	Depreciation
273.	2017	NC Util Com.	Docket No. E-7, SUB 1146	Duke Energy Carolinas, LLC	Depreciation
274.	2017	KY PSC	Case No. 2017-00321	Duke Energy Kentucky, Inc.	Depreciation
275.	2017	MA DPU	D.P.U. 18-40	Berkshire Gas Company	Depreciation
276.	2018	IN IURC	Cause No. 44992	Indiana-American Water Company, Inc.	Depreciation
277.	2018	IN IURC	Cause No. 45029	Indianapolis Power and Light	Depreciation
278.	2018	NC Util Com.	Docket No. W-218, Sub 497	Aqua North Carolina, Inc.	Depreciation
279.	2018	PA PUC	Docket No. R-2018-2647577	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
280.	2018	OR PUC	Docket UM 1933	Avista Corporation	Depreciation
281.	2018	WA UTC	Docket No. UE-108167	Avista Corporation	Depreciation
282.	2018	ID PUC	AVU-E-18-03, AVU-G-18-02	Avista Corporation	Depreciation
283.	2018	IN URC	Cause No. 45039	Citizens Energy Group	Depreciation
284.	2018	FERC	Docket No. ER18-	Duke Energy Progress	Depreciation
285.	2018	PA PUC	Docket No. R-2018-3000124	Duquesne Light Company	Depreciation
286.	2018	MD PSC	Case No. 948	NiSource - Columbia Gas of Maryland	Depreciation
287.	2018	MA DPU	D.P.U. 18-45	NiSource - Columbia Gas of Massachusetts	Depreciation
288.	2018	OH PUC	Case No. 18-0299-GA-ALT	Vectren Energy Delivery of Ohio	Depreciation
289.	2018	PA PUC	Docket No. R-2018-3000834	SUEZ Water Pennsylvania Inc.	Depreciation
290.	2018	MD PSC	Case No. 9847	Maryland-American Water Company	Depreciation
291.	2018	PA PUC	Docket No. R-2018-3000019	The York Water Company	Depreciation
292.	2018	FERC	ER-18-2231-000	Duke Energy Carolinas, LLC	Depreciation
293.	2018	KY PSC	Case No. 2018-00261	Duke Energy Kentucky, Inc.	Depreciation
294.	2018	NJ BPU	BPU Docket No. WR18050593	SUEZ Water New Jersey	Depreciation
295.	2018	WA UTC	Docket No. UE-180778	PacifiCorp	Depreciation
296.	2018	UT PSC	Docket No. 18-035-36	PacifiCorp	Depreciation
297.	2018	OR PUC	Docket No. UM-1968	PacifiCorp	Depreciation
298.	2018	ID PUC	Case No. PAC-E-18-08	PacifiCorp	Depreciation
299.	2018	WY PSC	20000-539-EA-18	PacifiCorp	Depreciation
300.	2018	PA PUC	Docket No. R-2018-3003068	Aqua Pennsylvania, Inc.	Depreciation

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301.	2018	IL CC	Docket No. 18-1467	Aqua Illinois, Inc.	Depreciation
302.	2018	KY PSC	Case No. 2018-00294	Louisville Gas & Electric Company	Depreciation
303.	2018	KY PSC	Case No. 2018-00295	Kentucky Utilities Company	Depreciation
304.	2018	IN URC	Cause No. 45159	Northern Indiana Public Service Company	Depreciation
305.	2018	VA SCC	Case No. PUR-2019-00175	Virginia American Water Company	Depreciation
306.	2019	PA PUC	Docket No. R-2018-3006818	Peoples Natural Gas Company, LLC	Depreciation
307.	2019	OK CC	Cause No. PUD201800140	Oklahoma Gas and Electric Company	Depreciation
308.	2019	MD PSC	Case No. 9490	FirstEnergy – Potomac Edison	Depreciation
309.	2019	SC PSC	Docket No. 2018-318-E	Duke Energy Progress	Depreciation
310.	2019	SC PSC	Docket No. 2018-319-E	Duke Energy Carolinas	Depreciation
311.	2019	DE PSC	DE 19-057	Public Service of New Hampshire	Depreciation
312.	2019	NY PSC	Case No. 19-W-0168 & 19-W-0269	SUEZ Water New York	Depreciation
313.	2019	PA PUC	Docket No. R-2019-3006904	Newtown Artesian Water Company	Depreciation
314.	2019	MO PSC	ER-2019-0335	Ameren Missouri	Depreciation
315.	2019	MO PSC	EC-2019-0200	KCP&L Greater Missouri Operations Company	Depreciation
316.	2019	MN DOC	G011/D-19-377	Minnesota Energy Resource Corp.	Depreciation
317.	2019	NY PSC	Case 19-E-0378 & 19-G-0379	New York State Electric and Gas Corporation	Depreciation
318.	2019	NY PSC	Case 19-E-0380 & 19-G-0381	Rochester Gas and Electric Corporation	Depreciation
319.	2019	WA UTC	Docket UE-190529 / UG-190530	Puget Sound Energy	Depreciation
320.	2019	PA PUC	Docket No. R-2019-3010955	City of Lancaster	Depreciation
321.	2019	IURC	Cause No. 45253	Duke Energy Indiana	Depreciation
322.	2019	KY PSC	Case No. 2019-00271	Duke Energy Kentucky, Inc.	Depreciation
323.	2019	OH PUC	Case No. 18-1720-GA-AIR	Northeast Ohio Natural Gas Corp	Depreciation
324.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Carolinas	Depreciation
325.	2019	FERC	Docket No. ER20-277-000	Jersey Central Power & Light Company	Depreciation
326.	2019	MA DPU	D.P.U. 19-120	NSTAR Gas Company	Depreciation
327.	2019	SC PSC	Docket No. 2019-290-WS	Blue Granite Water Company	Depreciation
328.	2019	NC Util. Com.	Docket No. E-2, Sub 1219	Duke Energy Progress	Depreciation
329.	2019	MD PSC	Case No. 9609	NiSource Columbia Gas of Maryland, Inc.	Depreciation
330.	2019	HI PUC	Docket No. 2019-0117	Young Brothers, LLC	Depreciation
331.	2020	NJ BPU	Docket No. ER20020146	Jersey Central Power & Light Company	Depreciation
332.	2020	PA PUC	Docket No. R-2020-3018835	NiSource - Columbia Gas of Pennsylvania, Inc.	Depreciation
333.	2020	PA PUC	Docket No. R-2020-3019369	Pennsylvania-American Water Company	Depreciation
334.	2020	PA PUC	Docket No. R-2020-3019371	Pennsylvania-American Water Company	Depreciation
335.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation
336.	2020	NM PRC	Case No. 20-00104-UT	El Paso Electric Company	Depreciation
337.	2020	MD PSC	Case No. 9644	Columbia Gas of Maryland, Inc.	Depreciation
338.	2020	MO PSC	GO-2018-0309, GO-2018-0310	Spire Missouri, Inc.	Depreciation

	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
339.	2020	VA St CC	Case No. PUR-2020-00095	Virginia Natural Gas Company	Depreciation
340.	2020	SC PSC	Docket No. 2020-125-E	Dominion Energy South Carolina, Inc.	Depreciation
341.	2020	WV PSC	Case No. 20-0745-G-D	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	Depreciation
342.	2020	VA St CC	Case No. PUR-2020-00106	Aqua Virginia, Inc.	Depreciation
343.	2020	PA PUC	Docket No. R-2020-3020256	City of Bethlehem – Bureau of Water	Depreciation
344.	2020	NE PSC	Docket No. NG-109	Black Hills Nebraska	Depreciation
345.	2020	NY PSC	Case No. 20-E-0428 & 20-G-0429	Central Hudson Gas & Electric Corporation	Depreciation
346.	2020	FERC	ER20-598	Duke Energy Indiana	Depreciation
347.	2020	FERC	ER20-855	Northern Indiana Public Service Company	Depreciation
348.3	2020	OR PSC	UE 374	PacifiCorp	Depreciation
349.	2020	MD PSC	Case No. 9490 Phase II	Potomac Edison – Maryland	Depreciation
350.	2020	IN URC	Case No. 45447	Southern Indiana Gas and Electric Company	Depreciation
351.	2020	IN URC	IURC Cause No. 45468	Indiana Gas Company, Inc. d/b/a Vectren Energy Delivery of Indiana, Inc.	Depreciation
352.	2020	KY PSC	Case No. 2020-00349	Kentucky Utilities Company	Depreciation
353.	2020	KY PSC	Case No. 2020-00350	Louisville Gas and Electric Company	Depreciation
354.	2020	FERC	Docket No. ER21- 000	South FirstEnergy Operating Companies	Depreciation
355.	2020	OH PUC	Case Nos 20-1651-EL-AIR, 20-1652-EL-AAM & 20-1653-EL-ATA	Dayton Power and Light Company	Depreciation
356.	2020	OR PSC	UG 388	Northwest Natural Gas Company	Depreciation
357.	2020	MO PSC	Case No. GR-2021-0241	Ameren Missouri Gas	Depreciation
358.	2021	KY PSC	Case No. 2021-00103	East Kentucky Power Cooperative	Depreciation
359.	2021	MPUC	Docket No. 2021-00024	Bangor Natural Gas	Depreciation
360.	2021	PA PUC	Docket No. R-2021-3024296	Columbia Gas of Pennsylvania, Inc.	Depreciation
361.	2021	NC Util. Com.	Doc. No. G-5, Sub 632	Public Service of North Carolina	Depreciation
362.	2021	MO PSC	ER-2021-0240	Ameren Missouri	Depreciation
363.	2021	PA PUC	Docket No. R-2021-3024750	Duquesne Light Company	Depreciation
364.	2021	KS PSC	21-BHCG-418-RTS	Black Hills Kansas Gas	Depreciation
365.	2021	KY PSC	Case No. 2021-00190	Duke Energy Kentucky	Depreciation
366.	2021	OR PSC	Docket UM 2152	Portland General Electric	Depreciation
367.	2021	ILL CC	Docket No. 20-0810	North Shore Gas Company	Depreciation
368.	2021	FERC	ER21-1939-000	Duke Energy Progress	Depreciation
369.	2021	FERC	ER21-1940-000	Duke Energy Carolina	Depreciation
370.	2021	KY PSC	Case No. 2021-00183	NiSource Columbia Gas of Kentucky	Depreciation
371.	2021	MD PSC	Case No. 9664	NiSource Columbia Gas of Maryland	Depreciation
372.	2021	OH PUC	Case No. 21-0596-ST-AIR	Aqua Ohio	Depreciation
373.	2021	PA PUC	Docket No. R-2021-3026116	Hanover Borough Municipal Water Works	Depreciation
374.	2021	OR PSC	UM-2180	Idaho Power Company	Depreciation
375.	2021	ID PUC	Case No. IPC-E-21-18	Idaho Power Company	Depreciation

	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
376.	2021	WPSC	6690-DU-104	Wisconsin Public Service Company	Depreciation
377.	2021	PAPUC	Docket No. R-2021-3026116	Borough of Hanover	Depreciation
378.	2021	OH PUC	Case No. 21-637-GA-AIR; Case No. 21-638-GA-ALT; Case No. 21-639-GA-UNC; Case No. 21-640-GA-AAM	NiSource Columbia Gas of Ohio	Depreciation
379.	2021	TX PUC	Texas PUC Docket No. 52195; SOHA Docket No. 473-21-2606	El Paso Electric	Depreciation
380.	2021	MO PSC	Case No. GR.2021-0108	Spire Missouri	Depreciation
381.	2021	WV PSC	Case No. 21-0215-WS-P	West Virginia American Water Company	Depreciation
382.	2021	FERC	ER21-2736	Duke Energy Carolinas	Depreciation
383.	2021	FERC	ER21-2737	Duke Energy Progress	Depreciation
384.	2021	IN URC	Cause #45621	Northern Indiana Public Service Company	Depreciation
385.	2021	PA PUC	Docket No. R-2021-3026682	City of Lancaster	Depreciation
386.	2021	OH PUC	Case No. 21-887-EL-AIR; Case No. 21-888-EL-ATA; Case No. 889-EL-AAM	Duke Energy Ohio	Depreciation
387.	2021	AK PSC	Docket No. 21-097-U	Black Hills Energy Arkansas, Inc.	Depreciation
388.	2021	OK CC	Cause No. PUD202100164	Oklahoma Gas & Electric	Depreciation
389.	2021	FERC	Case ER-22-392-001	El Paso Electric	Depreciation
390.	2021	FERC	Case ER-21-XXX	MidAmerican Electric	Depreciation
391.	2021	PA PUC	Docket Nos. R-2021-3027385, R-2021-3027386	Aqua Pennsylvania, Inc. Aqua Pennsylvania Wastewater, Inc.	Depreciation
392.	2022	FERC	Case ER-22-282-000	El Paso Electric	Depreciation
393.	2022	ILL CC	Docket No. 22-0154	MidAmerican Gas	Depreciation
394.	2022	MO PSC	Case No. ER-2022-0129	Evergy Metro	Depreciation
395.	2022	MO PSC	Case No. ER-2022-0130	Evergy Missouri West	Depreciation
396.	2022	PA PUC	Docket No. R-2022-3031211	NiSource Columbia Gas of Pennsylvania, Inc.	Depreciation
397.	2022	MA DPU	D.P.U. 22-20	The Berkshire Gas Company	Depreciation
398.	2022	PA PUC	R-2022-3031672; R-2022-3031673	Pennsylvania-American Water Company	Depreciation
399.	2022	SD PUC	Docket No. NG22-	MidAmerican Gas	Depreciation
400.	2022	MD PSC	Case No. 9680	NiSource Columbia Gas of Maryland	Depreciation
401.	2022	WYPSC	Docket No. 20003-214-ER-22	Black Hills Energy – Cheyenne Light, Fuel and Power Company	Depreciation
402.	2022	MA DPU	D.P.U. 22.22	NSTAR Electric Company d/b/a Eversource Energy	Depreciation
403.	2022	NC Util Com	Docket No. W-218, Sub 573	Aqua North Carolina, Inc.	Depreciation
404.	2022	OR PUC	UM2213	Northwest Natural Gas	Depreciation

	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
405.	2022	OR PUC	UM2214	Northwest Natural Gas	Depreciation
406.	2022	ME PUC	Docket No. 2022-00152	Central Maine Power	Depreciation
407.	2022	SC PSC	Docket No. 2022-254-E	Duke Energy Progress	Depreciation
408.	2022	NC Util	Docket No. E-2, SUB 1300	Duke Energy Progress	Depreciation
409.	2022	IN URC	Cause #45772	Northern Indiana Public Service Company	Depreciation
410.	2022	PA PUC	R-2022-3031340	The York Water Company	Depreciation
411.	2022	PA PUC	R-2022-3032806	The York Water Company	Depreciation
412.	2022	PA PUC	R-2022-3031704	Borough of Ambler	Depreciation
413.	2022	MO PSC	ER-2022-0337	Ameren Missouri	Depreciation
414.	2022	OH PUC	Case No. 22-507-GA-AIR	Duke Energy Ohio	Depreciation
415.	2022	PA PUC	R-2022-3035730	National Fuel Gas Distribution Corporation – PA Division	Depreciation
416.	2022	NC Util	Docket No. E-22, Sub 493	Virginia Electric and Power Company	Depreciation
417.	2022	WY PSC	20003-214-ER-22	Cheyenne Light, Fuel and Power Company	Depreciation
418.	2022	NJ BPU	BPU Docket No. ER2303144	Jersey Central Power & Light Company	Depreciation
419.	2022	KY PSC	Case No. 2022-00372	Duke Energy Kentucky	Depreciation
420.	2022	TX PUC	SOAH Docket No. 473-23-04521	Aqua Texas, Inc.	Depreciation
421.	2022	NC Util	Docket No. E-7, Sub 1276	Duke Energy Carolinas, LLC	Depreciation
422.	2022	KY PSC	Case No. 2022-00432	Bluegrass Water	Depreciation
423.	2023	ILL CC	Docket No. 23-0069	The Peoples Gas Light and Coke Company	Depreciation
424.	2023	ILL CC	Docket No. 23-0068	North Shore Gas Company	Depreciation
425.	2023	WV PSC	Case No. 23-0030-E-D	Monongahela Power Company and The Potomac Edison Company	Depreciation
426.	2023	ID PUC	AVU-E-23-01; AVU-G-23-01	Avista Corporation	Depreciation
427.	2023	ILL CC	Docket No. 23-0066	Northern Illinois Gas Company d/b/a Nicor Gas Company	Depreciation
428.	2023	SC PSC	Docket No. 2023-70-G	Dominion Energy South Carolina, Inc.	Depreciation
429.	2023	FERC	Docket No. ER23-xxx-00	Duke Energy Ohio, Inc.	Depreciation
430.	2023	WY PSC	Docket No. 30036-78-GR-23	Black Hills Wyoming Gas Company d/b/a Black Hills Energy	Depreciation
431.	2023	MD PSC	Case No. 9695	The Potomac Edison Company	Depreciation
432.	2023	OR PUC	Case No. UM2277	Avista Corporation	Depreciation
433.	2023	FERC	Docket No. ER23-1629-000	PPL Electric Utilities	Depreciation
434.	2023	OH PUC	Case No. 23-0154-GA-AIR	Northeast Ohio Natural Gas Corporation	Depreciation
435.	2023	DE PSC	PSC Docket No. 23-0601	Artesian Water Company	Depreciation
436.	2023	CO PUC	No. 23AL-0231G	Black Hills Colorado d/b/a Black Hills Energy	Depreciation
437.	2023	NH PUC	Docket No. DE 23-039	Granite State Electric d/b/a Liberty Utilities	Depreciation
438.	2023	MD PSC	Case No. 9701	Columbia Gas of Maryland	Depreciation
439.	2023	NY PSC	Case Nos. 23-E-0418; 23-G-0419	Central Hudson Gas and Electric	Depreciation
440.	2023	FERC	Docket No. ER23-xxx-000	Central Maine Power Company	Depreciation
441.	2023	SD PUC	Docket Number EL23-016	Northwestern Energy	Depreciation

	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	<u>Subject</u>
442.	2023	CT PURA	Docket No. 23-08-32	Connecticut Water Company	Depreciation
443.	2023	OH PUC	Case 23-0894-GA-AIR	The East Ohio Gas Company d/b/a Dominion Energy Ohio	Depreciation
444.	2023	IN URC	Cause No. 45911	Indianapolis Power & Light	Depreciation
445.	2023	IN URC	Cause No. 45967	Northern Indiana Public Service Company	Depreciation
446.	2023	PA PUC	Docket No. R-2023-3043189 and Docket No. R-2023-3043190	Pennsylvania-American Water Company	Depreciation
447.	2023	IN URC	Cause No. 45988	Citizens Energy Group	Depreciation
448.	2023	NY PSC	Case No. 23-G-0627	National Fuel Gas Distribution Corporation	Depreciation
449.	2023	IN URC	Cause No. 45990	Southern Indiana Gas and Electric Company d/b/a Centerpoint Energy Indiana South	Depreciation
450.	2023	PA PUC	Docket No. R-2023-3044549	Peoples Natural Gas Company LLC	Depreciation
451.	2023	OR PUC	Docket No. UM-2312	Northwest Natural Gas Company	Depreciation
452.	2023	AZ PCC	Docket No. WS-21182A-23-2092	Northwest Natural Water Company, LLC	Depreciation
453.	2023	SC PSC	Docket No. 2023-388-E	Duke Energy Carolinas	Depreciation
454.	2024	FERC	Docket No. ER24-768-000	Duke Energy Progress	Depreciation
455.	2024	FERC	Docket No. ER24-2057	Duke Energy Carolina	Depreciation
456.	2024	FERC	Docket No. SPP-0007	Evergy Metro, Inc. and Evergy Missouri West, Inc.	Depreciation
457.	2024	NJ BPU	Docket No. WR24010057	Aqua New Jersey, Inc.	Depreciation
458.	2024	ILL CC	Docket No. 24-0044	Aqua Illinois, Inc.	Depreciation
459.	2024	PA PUC	Docket No. R-2024-3046519	NiSource – Columbia Gas of Pennsylvania, Inc.	Depreciation
460.	2024	KY PSC	Case No. 2024-00092	NiSource – Columbia Gas of Kentucky, Inc.	Depreciation
461.	2024	VA SCC	Case No. PUR-2024-00030	NiSource – Columbia Gas of Virginia, Inc.	Depreciation
462.	2024	NE PSC	Docket No. 24-	Northwestern Energy	Depreciation
463.	2024	IA Util Bd	Docket No. RPU-2023-0002	Alliant - Interstate Power and Light Company	Depreciation
464.	2024	PA PUC	Docket No. R-2024-3047068	FirstEnergy Pennsylvania – Metropolitan Edison; Pennsylvania Electric; Pennsylvania Power; West Penn Power	Depreciation
465.	2024	PA PUC	Docket No. R-2024-3046523	Duquesne Light Company	Depreciation
466.	2024	NCUC	Docket No. E-22, Sub 694	Dominion Energy North Carolina	Depreciation
467.	2024	IN URC	IURC Cause No. 46038	Duke Energy Indiana	Depreciation
468.	2024	NJ BPU	Docket Nos. ER23120924 and GF 23120925	Public Service Electric and Gas Company	Depreciation
469.	2024	CO PUC	Docket No. 24-AL-0275E	Black Hills Colorado Electric, LLC	Depreciation
470.	2024	OH PUC	Case No. 24-0468-EL-AIR, Case No. 24-0469-EL-ATA, Case No. 24-0470-EL-AAM, Case No. 24-0471-EL-UNC	FirstEnergy Ohio	Depreciation

	<u>Year</u>	<u>Jurisdiction</u>	<u>Docket No.</u>	<u>Client Utility</u>	
471.	2024	SD PUC	Docket No. NG24-005	Northwestern Energy	Depreciation
472.	2024	PA PUC	Docket No. R-2024-3047822	Aqua Pennsylvania, Inc	Depreciation
473.	2024	PA PUC	Docket No. R-2024-3047824	Aqua Pennsylvania Wastewater, Inc	Depreciation
474.	2024	NH PUC	Docket No. DE 24-070	Eversource Energy - Public Service of New Hampshire	Depreciation
475.	2024	VA SCC	Case No. PUR-2024-00048	Virginia Natural Gas Company	Depreciation
476.	2024	WV PSC	Case No. 24-0678-G-D	Hope Gas, Inc.	Depreciation
477.	2024	MO PSC	ER-2024-0319	Ameren Missouri	Depreciation
478.	2024	PA PUC	Docket No. R-2024-3050208	Newtown Artesian Water Company	Depreciation
479.	2024	PA PUC	Docket No. RP-24-1106-00	Adelphia Gateway	Depreciation
480.	2024	OH PUC	Case No. 24-0832-GA-AIR	Centerpoint Energy Ohio	Depreciation
481.	2024	MT PSC	Docket 2024-05-053	Northwestern Energy	Depreciation
482.	2024	MD PSC	Case No. 9754	NiSource – Columbia Gas of Maryland	Depreciation
483.	2024	IURC	Cause No. 46120	Northern Indiana Public Service Company LLC	Depreciation
484.	2024	MO PSC	GR-2024-0369	Ameren Missouri	Depreciation
485.	2024	PUCO	Case No. 24-1009-EL-AIR, Case No. 24-1010-EL-AAM, Case No. 24-1011-EL-ATA	The Dayton Power and Light Company d/b/a AES Ohio	Depreciation
486.	2024	KY PSC	Case No. 2024-00092	Duke Energy Kentucky	Depreciation
487.	2024	MO PSC	GR-2025-0107	Spire Missouri, Inc.	Depreciation
488.	2024	PUCO	UG 520	Northwest Natural Gas	Depreciation

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2025						
	Nov 30	Rates							DECEMBER						
	Begin. Balance	11-2025							Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	16,191	0	16,191	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	22,613	0	22,613	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	49,899	0	49,899	0	0	0	1,072,322
352.10	206,932	0.00			0			0	9	0	9	0	0	0	206,941
353.00	385,707	0.02			118			118	90	477	567	0	0	0	385,797
354.00	945,591	0.22			0			0	2,047	0	2,047	0	0	0	947,638
354.10	0	19.88			0			0	8,159	0	8,159	0	0	0	8,636
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,068	1,167	16,235	11,275	0	0	1,278,004
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,933,706
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	16,474	3,104	19,579	34,733	14,588	0	1,659,678
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	76,659
375.70	10,224,250	2.60			18			16	111,855	2	111,857	0	0	0	10,336,107
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,684
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,299,975	106,551	6,406,526	10,856,392	868,511	0	457,479,091
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	488,224	10,682	498,906	980,438	117,653	0	37,139,845
379.10	43,635	8.11			6			6	805	1	806	0	0	0	44,441
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,527,053	309,692	2,836,745	2,985,842	895,753	0	193,540,685
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	108,894	4,005	112,900	308,142	15,407	0	16,971,613
381.10	21,272,655	2.52			0			0	57,679	0	57,679	54,378	0	0	21,275,956
382.00	17,253,364	1.93			486			486	88,650	41	88,690	108,786	0	0	17,233,268
383.00	6,249,223	2.03	0.00		185	0.00		0	34,821	15	34,837	56,327	0	0	6,227,732
384.00	2,972,542	1.31			0			0	3,833	0	3,833	1,192	0	0	2,975,183
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	39,054	5,151	44,205	46,745	10,284	0	3,092,372
387.00	91,475	2.56			0			0	292	0	292	0	0	0	91,767
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	966	84,681	0	0	0	3,885,149
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,091,708
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,633,116
391.11	70,430	5.66			0			0	431	0	431	0	0	0	70,861
391.12	127,821	1.05			0			0	114	0	114	0	0	0	127,935
392.00	25,921	0.00			194			194	0	16	16	0	0	0	25,937
394.00	8,463,352	3.97			0			0	91,250	0	91,250	0	0	0	8,554,602
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	133,507
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	0	0	0	0	984,967
397.50	585,348	6.08			0			0	16,273	0	16,273	112,292	0	0	489,329
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	703,711
					0			0							
303.00	33,269,871				0			0	1,200,074	0	1,200,074	432,816	0	0	34,037,128
303.60	8,282,412				0			0	344,490	0	344,490	158,960	0	0	8,467,942
362.10	(175,383)				84,665			71,418	0	7,055	7,055	0	0	0	(168,328)
375.71	4,032,971				0			0	79,428	0	79,428	0	0	0	4,112,399
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,345
Total	849,818,430				5,376,232			5,484,681	11,753,872	448,487	12,202,358	16,148,318	1,922,196	0	843,950,275

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates			Amort of NS			Amort of NS	JANUARY						
	Begin. Balance	11-2025			2020-2024			2021-2025	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118			0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	8,986	0	8,986	0	0	0	17,622
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,109	1,164	16,273	250	0	0	1,294,026
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,936,589
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	16,621	2,837	19,458	372	156	0	1,678,608
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	76,697
375.70	10,224,250	2.60			18			16	111,879	1	111,880	0	0	0	10,447,987
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,712
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,342,992	140,705	6,483,697	119,824	9,586	0	463,833,379
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	493,390	13,670	507,060	8,635	1,036	0	37,637,234
379.10	43,635	8.11			6			6	805	1	806	0	0	0	45,247
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,543,737	281,994	2,825,732	33,238	9,971	0	196,323,207
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	110,276	5,961	116,236	3,563	178	0	17,084,108
381.10	21,272,655	2.52			0			0	57,917	0	57,917	629	0	0	21,333,244
382.00	17,253,364	1.93			486			486	89,051	41	89,091	1,705	0	0	17,320,655
383.00	6,249,223	2.03	0.00		185	0.00		0	35,065	0	35,065	1,182	0	0	6,261,616
384.00	2,972,542	1.31			0			0	3,836	0	3,836	26	0	0	2,978,993
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	39,440	4,207	43,647	483	106	0	3,135,430
387.00	91,475	2.56			0			0	292	0	292	0	0	0	92,058
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	3,969,801
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,097,908
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,662,876
391.11	70,430	5.66			0			0	431	0	431	0	0	0	71,291
391.12	127,821	1.05			0			0	114	0	114	0	0	0	128,048
392.00	25,921	0.00			194			194	0	16	16	0	0	0	25,953
394.00	8,463,352	3.97			0			0	93,370	0	93,370	0	0	0	8,647,972
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	134,699
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0	984,477
397.50	585,348	6.08			0			0	17,628	0	17,628	1,957	0	0	505,000
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	710,018
					0			0							
303.00	33,269,871				0			0	1,193,559	0	1,193,559	987,927	0	0	34,242,761
303.60	8,282,412				0			0	345,855	0	345,855	0	0	0	8,813,797
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(162,376)
375.71	4,032,971				0			0	79,428	0	79,428	0	0	0	4,191,827
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,398
Total	849,818,430				5,376,232			5,484,681	11,729,907	457,047	12,186,954	1,159,790	21,034	0	854,956,404

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates							FEBRUARY						
	Begin. Balance	11-2025							Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118		0	0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	9,212	0	9,212	0	0	0	26,834
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,139	1,164	16,303	988	0	0	1,309,341
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,939,472
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	16,694	2,837	19,531	1,668	701	0	1,695,770
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	76,736
375.70	10,224,250	2.60			18			16	111,987	1	111,989	0	0	0	10,559,976
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,741
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,363,847	140,705	6,504,552	491,001	39,280	0	469,807,650
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	495,254	13,670	508,924	25,844	3,101	0	38,117,212
379.10	43,635	8.11			6			6	805	1	806	0	0	0	46,052
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,552,239	281,994	2,834,233	149,979	44,994	0	198,962,468
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	111,005	5,961	116,965	16,352	818	0	17,183,904
381.10	21,272,655	2.52			0			0	58,043	0	58,043	2,886	0	0	21,388,401
382.00	17,253,364	1.93			486			486	89,300	41	89,341	7,085	0	0	17,402,910
383.00	6,249,223	2.03	0.00		185	0.00		0	35,244	0	35,244	4,703	0	0	6,292,157
384.00	2,972,542	1.31			0			0	3,839	0	3,839	104	0	0	2,982,728
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	39,626	4,207	43,833	2,181	480	0	3,176,602
387.00	91,475	2.56			0			0	292	0	292	0	0	0	92,350
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	4,054,452
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,104,109
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,692,637
391.11	70,430	5.66			0			0	431	0	431	0	0	0	71,722
391.12	127,821	1.05			0			0	114	0	114	0	0	0	128,162
392.00	25,921	0.00			194			194	0	16	16	0	0	0	25,970
394.00	8,463,352	3.97			0			0	95,335	0	95,335	0	0	0	8,743,307
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	135,891
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0	983,988
397.50	585,348	6.08			0			0	18,474	0	18,474	6,996	0	0	516,478
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	716,326
					0			0							
303.00	33,269,871				0			0	1,213,324	0	1,213,324	59,126	0	0	35,396,958
303.60	8,282,412				0			0	347,171	0	347,171	0	0	0	9,160,968
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(156,425)
375.71	4,032,971				0			0	81,333	0	81,333	0	0	0	4,273,160
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,450
Total	849,818,430				5,376,232			5,484,681	11,788,833	457,047	12,245,880	768,914	89,373	0	866,343,998

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates			Amort of NS			Amort of NS	MARCH						
	Begin. Balance	11-2025			2020-2024			2021-2025	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118			0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	9,497	0	9,497	0	0	0	36,331
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,173	1,164	16,337	1,544	0	0	1,324,134
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,942,355
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	16,780	2,837	19,617	2,593	1,089	0	1,711,705
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	76,774
375.70	10,224,250	2.60			18			16	112,106	1	112,108	0	0	0	10,672,084
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,769
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,387,471	140,705	6,528,176	771,802	61,744	0	475,502,280
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	497,025	13,670	510,695	41,462	4,975	0	38,581,470
379.10	43,635	8.11			6			6	805	1	806	0	0	0	46,858
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,562,321	281,994	2,844,315	233,054	69,916	0	201,503,812
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	111,877	5,961	117,838	25,392	1,270	0	17,275,080
381.10	21,272,655	2.52			0			0	58,193	0	58,193	4,481	0	0	21,442,113
382.00	17,253,364	1.93			486			486	89,584	41	89,624	11,048	0	0	17,481,486
383.00	6,249,223	2.03	0.00		185	0.00		0	35,442	0	35,442	7,347	0	0	6,320,251
384.00	2,972,542	1.31			0			0	3,842	0	3,842	163	0	0	2,986,406
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	39,846	4,207	44,054	3,389	746	0	3,216,522
387.00	91,475	2.56			0			0	292	0	292	0	0	0	92,641
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	4,139,104
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,110,309
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,722,398
391.11	70,430	5.66			0			0	431	0	431	0	0	0	72,153
391.12	127,821	1.05			0			0	114	0	114	0	0	0	128,276
392.00	25,921	0.00			194			194	0	16	16	0	0	0	25,986
394.00	8,463,352	3.97			0			0	97,587	0	97,587	0	0	0	8,840,894
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	137,084
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	0	0	0	0	983,498
397.50	585,348	6.08			0			0	19,420	0	19,420	12,226	0	0	523,672
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	722,634
					0			0							
303.00	33,269,871				0			0	1,211,135	0	1,211,135	697,570	0	0	35,910,523
303.60	8,282,412				0			0	346,185	0	346,185	153,636	0	0	9,353,517
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(150,473)
375.71	4,032,971				0			0	81,524	0	81,524	0	0	0	4,354,684
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,503
Total	849,818,430				5,376,232			5,484,681	11,826,774	457,047	12,283,821	1,965,707	139,740	0	876,522,372

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates			Amort of NS			Amort of NS	APRIL						
	Begin. Balance	11-2025			2020-2024			2021-2025	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118			0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	9,879	0	9,879	0	0	0	46,210
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,203	1,164	16,367	867	0	0	1,339,634
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,945,238
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	16,881	2,837	19,718	2,934	1,232	0	1,727,256
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	76,813
375.70	10,224,250	2.60			18			16	112,128	1	112,129	0	0	0	10,784,212
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,797
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,417,002	140,705	6,557,707	978,148	78,252	0	481,003,587
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	499,188	13,670	512,859	49,385	5,926	0	39,039,017
379.10	43,635	8.11			6			6	805	1	806	0	0	0	47,664
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,574,332	281,994	2,856,326	270,735	81,221	0	204,008,182
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	112,947	5,961	118,908	31,321	1,566	0	17,361,101
381.10	21,272,655	2.52			0			0	58,377	0	58,377	5,527	0	0	21,494,963
382.00	17,253,364	1.93			486			486	89,870	41	89,910	8,809	0	0	17,562,588
383.00	6,249,223	2.03	0.00		185	0.00		0	35,622	0	35,622	4,372	0	0	6,351,501
384.00	2,972,542	1.31			0			0	3,844	0	3,844	92	0	0	2,990,159
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	40,109	4,207	44,317	3,943	867	0	3,256,028
387.00	91,475	2.56			0			0	292	0	292	0	0	0	92,933
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	4,223,755
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,116,510
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,752,158
391.11	70,430	5.66			0			0	431	0	431	0	0	0	72,583
391.12	127,821	1.05			0			0	114	0	114	0	0	0	128,390
392.00	25,921	0.00			194			194	0	16	16	0	0	0	26,002
394.00	8,463,352	3.97			0			0	99,923	0	99,923	0	0	0	8,940,817
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	138,276
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	0	0	0	0	983,009
397.50	585,348	6.08			0			0	20,398	0	20,398	9,267	0	0	534,803
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	728,941
					0			0							
303.00	33,269,871				0			0	1,159,197	0	1,159,197	3,913,381	0	0	33,156,339
303.60	8,282,412				0			0	345,108	0	345,108	156,244	0	0	9,542,382
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(144,522)
375.71	4,032,971				0			0	81,705	0	81,705	0	0	0	4,436,389
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,555
Total	849,818,430				5,376,232			5,484,681	11,823,482	457,047	12,280,529	5,435,024	169,065	0	883,198,813

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates			Amort of NS			Amort of NS	MAY						
	Begin. Balance	11-2025			2020-2024			2021-2025	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118			0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	10,295	0	10,295	0	0	0	56,505
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,222	1,164	16,386	1,048	0	0	1,354,971
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,948,121
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	16,978	2,837	19,815	3,405	1,430	0	1,742,237
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	76,851
375.70	10,224,250	2.60			18			16	112,181	1	112,183	0	0	0	10,896,395
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,825
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,446,776	140,705	6,587,481	1,121,828	89,746	0	486,379,494
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	501,356	13,670	515,026	59,505	7,141	0	39,487,398
379.10	43,635	8.11			6			6	805	1	806	0	0	0	48,470
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,585,986	281,994	2,867,981	313,783	94,135	0	206,468,244
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	114,016	5,961	119,977	36,215	1,811	0	17,443,053
381.10	21,272,655	2.52			0			0	58,562	0	58,562	6,391	0	0	21,547,134
382.00	17,253,364	1.93			486			486	90,097	41	90,138	10,399	0	0	17,642,326
383.00	6,249,223	2.03	0.00		185	0.00		0	35,742	0	35,742	5,263	0	0	6,381,979
384.00	2,972,542	1.31			0			0	3,846	0	3,846	111	0	0	2,993,894
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	40,365	4,207	44,572	4,570	1,005	0	3,295,025
387.00	91,475	2.56			0			0	292	0	292	0	0	0	93,225
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	4,308,407
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,122,710
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,781,919
391.11	70,430	5.66			0			0	431	0	431	0	0	0	73,014
391.12	127,821	1.05			0			0	114	0	114	0	0	0	128,503
392.00	25,921	0.00			194			194	0	16	16	0	0	0	26,018
394.00	8,463,352	3.97			0			0	101,588	0	101,588	0	0	0	9,042,406
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	139,468
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0	982,520
397.50	585,348	6.08			0			0	21,088	0	21,088	9,090	0	0	546,801
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	735,249
					0			0							
303.00	33,269,871				0			0	1,107,563	0	1,107,563	3,942,327	0	0	30,321,575
303.60	8,282,412				0			0	346,774	0	346,774	0	0	0	9,889,155
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(138,570)
375.71	4,032,971				0			0	82,467	0	82,467	0	0	0	4,518,856
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,608
Total	849,818,430				5,376,232			5,484,681	11,822,670	457,047	12,279,717	5,513,937	195,268	0	889,769,325

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates			Amort of NS			Amort of NS	JUNE						
	Begin. Balance	11-2025			2020-2024			2021-2025	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118		0	0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	10,926	0	10,926	0	0	0	67,431
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,246	1,164	16,410	1,559	0	0	1,369,822
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,951,004
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	17,120	2,837	19,957	6,638	2,788	0	1,752,768
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	76,890
375.70	10,224,250	2.60			18			16	112,268	1	112,269	0	0	0	11,008,664
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,853
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,490,269	140,705	6,630,974	2,201,432	176,115	0	490,632,922
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	504,425	13,670	518,095	107,166	12,860	0	39,885,467
379.10	43,635	8.11			6			6	805	1	806	0	0	0	49,276
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,603,099	281,994	2,885,093	615,583	184,675	0	208,553,079
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	115,599	5,961	121,559	72,024	3,601	0	17,488,987
381.10	21,272,655	2.52			0			0	58,834	0	58,834	12,710	0	0	21,593,258
382.00	17,253,364	1.93			486			486	90,410	41	90,451	18,244	0	0	17,714,533
383.00	6,249,223	2.03	0.00		185	0.00		0	35,895	0	35,895	8,094	0	0	6,409,780
384.00	2,972,542	1.31			0			0	3,848	0	3,848	165	0	0	2,997,577
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	40,740	4,207	44,947	8,968	1,973	0	3,329,031
387.00	91,475	2.56			0			0	292	0	292	0	0	0	93,516
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	4,393,059
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,128,911
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,811,680
391.11	70,430	5.66			0			0	431	0	431	0	0	0	73,445
391.12	127,821	1.05			0			0	114	0	114	0	0	0	128,617
392.00	25,921	0.00			194			194	0	16	16	0	0	0	26,034
394.00	8,463,352	3.97			0			0	103,538	0	103,538	0	0	0	9,145,944
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	140,660
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0	982,030
397.50	585,348	6.08			0			0	21,890	0	21,890	14,211	0	0	554,480
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	741,557
					0			0							
303.00	33,269,871				0			0	1,091,716	0	1,091,716	1,805,626	0	0	29,607,665
303.60	8,282,412				0			0	302,921	0	302,921	2,790,958	0	0	7,401,118
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(132,619)
375.71	4,032,971				0			0	83,229	0	83,229	0	0	0	4,602,085
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,660
Total	849,818,430				5,376,232			5,484,681	11,833,742	457,047	12,290,789	7,663,380	382,012	0	894,014,723

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates			Amort of NS			Amort of NS	JULY						
	Begin. Balance	11-2025			2020-2024			2021-2025	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118			0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	11,644	0	11,644	0	0	0	79,076
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,264	1,164	16,427	272	0	0	1,385,977
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,953,887
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	17,272	2,837	20,109	3,537	1,486	0	1,767,854
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	76,928
375.70	10,224,250	2.60			18			16	112,507	1	112,509	0	0	0	11,121,173
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,882
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,538,752	140,705	6,679,457	1,274,952	101,996	0	495,935,430
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	507,821	13,670	521,491	65,548	7,866	0	40,333,544
379.10	43,635	8.11			6			6	805	1	806	0	0	0	50,081
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,621,652	281,994	2,903,646	332,489	99,747	0	211,024,489
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	117,341	5,961	123,302	40,023	2,001	0	17,570,264
381.10	21,272,655	2.52			0			0	59,135	0	59,135	7,063	0	0	21,645,330
382.00	17,253,364	1.93			486			486	90,705	41	90,745	7,378	0	0	17,797,901
383.00	6,249,223	2.03	0.00		185	0.00		0	36,013	0	36,013	1,810	0	0	6,443,983
384.00	2,972,542	1.31			0			0	3,850	0	3,850	29	0	0	3,001,398
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	41,146	4,207	45,354	4,848	1,067	0	3,368,470
387.00	91,475	2.56			0			0	292	0	292	0	0	0	93,808
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	4,477,710
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,135,111
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,841,440
391.11	70,430	5.66			0			0	431	0	431	0	0	0	73,875
391.12	127,821	1.05			0			0	114	0	114	0	0	0	128,731
392.00	25,921	0.00			194			194	0	16	16	0	0	0	26,050
394.00	8,463,352	3.97			0			0	105,435	0	105,435	0	0	0	9,251,378
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	141,852
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0	981,541
397.50	585,348	6.08			0			0	22,674	0	22,674	7,249	0	0	569,905
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	747,864
					0			0							
303.00	33,269,871				0			0	1,107,471	0	1,107,471	477,408	0	0	30,237,729
303.60	8,282,412				0			0	304,616	0	304,616	0	0	0	7,705,734
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(126,667)
375.71	4,032,971				0			0	86,678	0	86,678	0	0	0	4,688,763
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,712
Total	849,818,430				5,376,232			5,484,681	11,931,744	457,047	12,388,791	2,222,607	214,162	0	903,966,745

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates			Amort of NS			Amort of NS	AUGUST						
	Begin. Balance	11-2025			2020-2024			2021-2025	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118		0	0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	12,510	0	12,510	0	0	0	91,586
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,290	1,164	16,454	2,527	0	0	1,399,905
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,956,770
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	17,461	2,837	20,298	9,208	3,868	0	1,775,076
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	76,967
375.70	10,224,250	2.60			18			16	112,703	1	112,705	0	0	0	11,233,877
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,910
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,598,595	140,705	6,739,300	3,069,413	245,553	0	499,359,764
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	512,327	13,670	525,997	167,438	20,093	0	40,672,011
379.10	43,635	8.11			6			6	805	1	806	0	0	0	50,887
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,644,541	281,994	2,926,535	851,111	255,333	0	212,844,579
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	119,476	5,961	125,436	98,853	4,943	0	17,591,905
381.10	21,272,655	2.52			0			0	59,503	0	59,503	17,445	0	0	21,687,388
382.00	17,253,364	1.93			486			486	91,093	41	91,134	26,833	0	0	17,862,202
383.00	6,249,223	2.03	0.00		185	0.00		0	36,185	0	36,185	12,855	0	0	6,467,313
384.00	2,972,542	1.31			0			0	3,852	0	3,852	267	0	0	3,004,983
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	41,648	4,207	45,856	12,397	2,727	0	3,399,201
387.00	91,475	2.56			0			0	292	0	292	0	0	0	94,100
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	4,562,362
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,141,312
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,871,201
391.11	70,430	5.66			0			0	431	0	431	0	0	0	74,306
391.12	127,821	1.05			0			0	114	0	114	0	0	0	128,845
392.00	25,921	0.00			194			194	0	16	16	0	0	0	26,067
394.00	8,463,352	3.97			0			0	108,363	0	108,363	0	0	0	9,359,742
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	143,044
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	0	0	0	0	981,051
397.50	585,348	6.08			0			0	23,883	0	23,883	26,545	0	0	567,244
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	754,172
					0			0							
303.00	33,269,871				0			0	1,119,622	0	1,119,622	212,325	0	0	31,145,025
303.60	8,282,412				0			0	292,958	0	292,958	817,972	0	0	7,180,720
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(120,716)
375.71	4,032,971				0			0	86,678	0	86,678	0	0	0	4,775,441
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,765
Total	849,818,430				5,376,232			5,484,681	12,028,457	457,047	12,485,504	5,325,188	532,516	0	910,594,544

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates			Amort of NS			Amort of NS	SEPTEMBER						
	Begin. Balance	11-2025			2020-2024			2021-2025	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118			0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	13,308	0	13,308	0	0	0	104,894
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,322	1,164	16,485	1,235	0	0	1,415,155
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,959,653
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	17,639	2,837	20,476	5,057	2,124	0	1,788,372
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	77,005
375.70	10,224,250	2.60			18			16	112,703	1	112,705	0	0	0	11,346,582
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,938
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,654,824	140,705	6,795,530	1,809,943	144,795	0	504,200,554
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	516,996	13,670	530,666	126,997	15,240	0	41,060,440
379.10	43,635	8.11			6			6	805	1	806	0	0	0	51,693
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,666,062	281,994	2,948,056	468,596	140,579	0	215,183,460
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	121,463	5,961	127,424	54,732	2,737	0	17,661,860
381.10	21,272,655	2.52			0			0	59,845	0	59,845	9,659	0	0	21,737,575
382.00	17,253,364	1.93			486			486	91,491	41	91,532	14,097	0	0	17,939,637
383.00	6,249,223	2.03	0.00		185	0.00		0	36,383	0	36,383	6,378	0	0	6,497,318
384.00	2,972,542	1.31			0			0	3,854	0	3,854	131	0	0	3,008,707
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	42,120	4,207	46,327	6,826	1,502	0	3,437,200
387.00	91,475	2.56			0			0	292	0	292	0	0	0	94,391
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	4,647,013
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,147,512
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,900,962
391.11	70,430	5.66			0			0	431	0	431	0	0	0	74,736
391.12	127,821	1.05			0			0	114	0	114	0	0	0	128,958
392.00	25,921	0.00			194			194	0	16	16	0	0	0	26,083
394.00	8,463,352	3.97			0			0	111,373	0	111,373	0	0	0	9,471,115
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	144,236
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	0	0	0	0	980,562
397.50	585,348	6.08			0			0	25,112	0	25,112	13,471	0	0	578,885
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	760,480
					0			0							
303.00	33,269,871				0			0	1,126,040	0	1,126,040	421,691	0	0	31,849,374
303.60	8,282,412				0			0	294,628	0	294,628	0	0	0	7,475,348
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(114,764)
375.71	4,032,971				0			0	86,678	0	86,678	0	0	0	4,862,119
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,817
Total	849,818,430				5,376,232			5,484,681	12,127,610	457,047	12,584,657	2,938,814	306,976	0	919,933,410

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates			Amort of NS			Amort of NS	OCTOBER						
	Begin. Balance	11-2025			2020-2024			2021-2025	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118			0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	13,973	0	13,973	0	0	0	118,868
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,360	1,164	16,524	3,876	0	0	1,427,803
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,962,536
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	17,799	2,837	20,636	9,105	3,824	0	1,796,079
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	77,044
375.70	10,224,250	2.60			18			16	112,703	1	112,705	0	0	0	11,459,287
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,966
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,704,532	140,705	6,845,237	2,969,541	237,563	0	507,838,687
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	521,922	13,670	535,592	209,579	25,149	0	41,361,304
379.10	43,635	8.11			6			6	805	1	806	0	0	0	52,499
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,685,153	281,994	2,967,147	830,569	249,171	0	217,070,868
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	123,191	5,961	129,152	93,693	4,685	0	17,692,634
381.10	21,272,655	2.52			0			0	60,143	0	60,143	16,534	0	0	21,781,184
382.00	17,253,364	1.93			486			486	91,902	41	91,942	32,308	0	0	17,999,271
383.00	6,249,223	2.03	0.00		185	0.00		0	36,621	0	36,621	18,878	0	0	6,515,061
384.00	2,972,542	1.31			0			0	3,858	0	3,858	410	0	0	3,012,155
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	42,538	4,207	46,745	12,088	2,659	0	3,469,198
387.00	91,475	2.56			0			0	292	0	292	0	0	0	94,683
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	4,731,665
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,153,713
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,930,722
391.11	70,430	5.66			0			0	431	0	431	0	0	0	75,167
391.12	127,821	1.05			0			0	114	0	114	0	0	0	129,072
392.00	25,921	0.00			194			194	0	16	16	0	0	0	26,099
394.00	8,463,352	3.97			0			0	114,868	0	114,868	0	0	0	9,585,982
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	145,429
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	0	0	0	0	980,072
397.50	585,348	6.08			0			0	26,529	0	26,529	36,955	0	0	568,458
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	766,788
					0			0							
303.00	33,269,871				0			0	1,142,049	0	1,142,049	179,146	0	0	32,812,277
303.60	8,282,412				0			0	296,175	0	296,175	9,050	0	0	7,762,473
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(108,813)
375.71	4,032,971				0			0	86,678	0	86,678	0	0	0	4,948,796
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,870
Total	849,818,430				5,376,232			5,484,681	12,227,761	457,047	12,684,808	4,421,731	523,051	0	927,673,436

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates			Amort of NS			Amort of NS	NOVEMBER						
	Begin. Balance	11-2025			2020-2024			2021-2025	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118		0	0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	14,677	0	14,677	0	0	0	133,545
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,420	1,164	16,583	5,948	0	0	1,438,438
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,965,419
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	17,982	2,837	20,819	10,174	4,273	0	1,802,451
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	77,082
375.70	10,224,250	2.60			18			16	112,703	1	112,705	0	0	0	11,571,992
375.80	9,656	2.05			0			0	28	0	28	0	0	0	9,995
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,758,355	140,705	6,899,060	3,055,309	244,425	0	511,438,013
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	527,128	13,670	540,798	200,766	24,092	0	41,677,245
379.10	43,635	8.11			6			6	805	1	806	0	0	0	53,305
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,706,897	281,994	2,988,891	915,273	274,582	0	218,869,904
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	125,114	5,961	131,075	99,949	4,997	0	17,718,763
381.10	21,272,655	2.52			0			0	60,475	0	60,475	17,638	0	0	21,824,020
382.00	17,253,364	1.93			486			486	92,444	41	92,485	42,887	0	0	18,048,868
383.00	6,249,223	2.03	0.00		185	0.00		0	36,973	0	36,973	28,338	0	0	6,523,696
384.00	2,972,542	1.31			0			0	3,863	0	3,863	629	0	0	3,015,388
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	43,014	4,207	47,221	13,309	2,928	0	3,500,182
387.00	91,475	2.56			0			0	292	0	292	0	0	0	94,974
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	4,816,316
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,159,913
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,960,483
391.11	70,430	5.66			0			0	431	0	431	0	0	0	75,598
391.12	127,821	1.05			0			0	114	0	114	0	0	0	129,186
392.00	25,921	0.00			194			194	0	16	16	0	0	0	26,115
394.00	8,463,352	3.97			0			0	119,767	0	119,767	0	0	0	9,705,749
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	146,621
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0	979,583
397.50	585,348	6.08			0			0	28,477	0	28,477	48,694	0	0	548,242
398.00	697,403	6.38			0			0	6,308	0	6,308	0	0	0	773,095
					0			0							
303.00	33,269,871				0			0	1,155,080	0	1,155,080	108,894	0	0	33,858,463
303.60	8,282,412				0			0	297,289	0	297,289	34,080	0	0	8,025,681
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(102,861)
375.71	4,032,971				0			0	86,678	0	86,678	0	0	0	5,035,474
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,922
Total	849,818,430				5,376,232			5,484,681	12,334,103	457,047	12,791,150	4,581,888	555,297	0	935,327,402

RESERVE BRINGFORWARD

PROJECTED 2025									PROJECTED 2026						
Account	2025	'Accrual	COR	Salvage	'5-yr	COR	Salvage	'5-yr	2026						
	Nov 30	Rates			Amort of NS			Amort of NS	DECEMBER						
	Begin. Balance	11-2025			2020-2024			2021-2025	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,932	0.00							0	0	0	0	0	0	1,932
351.20	3,278,649	0.49			0			0	0	0	0	0	0	0	3,294,840
352.01	1,104,159	2.01			0			0	0	0	0	0	0	0	1,126,772
352.02	1,022,423	4.65			0			0	0	0	0	0	0	0	1,072,322
352.10	206,932	0.00			0			0	0	0	0	0	0	0	206,941
353.00	385,707	0.02			118			118		0	0	0	0	0	385,797
354.00	945,591	0.22			0			0	0	0	0	0	0	0	947,638
354.10	0	19.88			0			0	15,455	0	15,455	0	0	0	149,000
355.00	104,477	0.00			0			0	0	0	0	0	0	0	104,477
374.40	1,273,044	1.64			14,000			13,964	15,489	1,164	16,653	19,944	0	0	1,435,147
374.50	1,930,823	1.07			0			0	2,883	0	2,883	0	0	0	1,968,302
375.34	1,689,421	2.49	0.42		37,252	0.42		34,045	18,172	2,837	21,009	36,750	15,435	0	1,771,276
375.60	76,620	0.54	0.00		0	0.00		0	39	0	39	0	0	0	77,121
375.70	10,224,250	2.60			18			16	112,727	1	112,728	0	0	0	11,684,720
375.80	9,656	2.05			0			0	28	0	28	0	0	0	10,023
376.00	462,797,469	2.31	0.08		1,278,607	0.08		1,688,462	6,812,984	140,705	6,953,689	11,595,236	927,619	0	505,868,847
378.00	37,739,029	3.25	0.12		128,187	0.12		164,041	532,557	13,670	546,227	852,466	102,296	0	41,268,709
379.10	43,635	8.11			6			6	805	1	806	0	0	0	54,111
380.00	194,585,535	3.25	0.30		3,716,302	0.30		3,383,930	2,729,272	281,994	3,011,266	3,318,288	995,487	0	217,567,395
381.00	17,182,262	2.58	0.05		48,062	0.05		71,527	127,064	5,961	133,025	365,550	18,277	0	17,467,960
381.10	21,272,655	2.52			0			0	60,811	0	60,811	64,509	0	0	21,820,323
382.00	17,253,364	1.93			486			486	93,049	41	93,090	148,445	0	0	17,993,514
383.00	6,249,223	2.03	0.00		185	0.00		0	37,387	0	37,387	95,455	0	0	6,465,627
384.00	2,972,542	1.31			0			0	3,869	0	3,869	2,108	0	0	3,017,148
385.00	3,105,196	4.89	0.22		61,808	0.22		50,488	43,504	4,207	47,711	48,264	10,618	0	3,489,012
387.00	91,475	2.56			0			0	292	0	292	0	0	0	95,266
387.40	3,800,468	5.34	0.03		11,586	0.03		11,230	83,716	936	84,652	0	0	0	4,900,968
387.50	2,085,507	3.38			0			0	6,201	0	6,201	0	0	0	2,166,114
390.10	49,821	0.00			0			0	0	0	0	0	0	0	49,821
391.10	1,603,355	5.00			0			0	29,761	0	29,761	0	0	0	1,990,244
391.11	70,430	5.66			0			0	373	0	373	24,427	0	0	51,544
391.12	127,821	1.05			0			0	114	0	114	0	0	0	129,299
392.00	25,921	0.00			194			194	0	16	16	0	0	0	26,131
394.00	8,463,352	3.97			0			0	126,233	0	126,233	186,889	0	0	9,645,093
395.00	132,315	5.40			0			0	1,192	0	1,192	0	0	0	147,813
396.00	985,456	0.00			(5,873)			(5,873)	0	(489)	(489)	0	0	0	979,094
397.50	585,348	6.08			0			0	30,853	0	30,853	195,592	0	0	383,504
398.00	697,403	6.38			0			0	6,291	0	6,291	6,123	0	0	773,264
					0			0							0
303.00	33,269,871				0			0	1,160,706	0	1,160,706	1,860,114	0	0	33,159,055
303.60	8,282,412				0			0	297,477	0	297,477	118,441	0	0	8,204,718
362.10	(175,383)				84,665			71,418	0	5,952	5,952	0	0	0	(96,910)
375.71	4,032,971				0			0	86,678	0	86,678	0	0	0	5,122,152
NonDeprPlant	235,293				629			629	0	52	52	0	0	0	235,974
Total	849,818,430				5,376,232			5,484,681	12,435,982	457,047	12,893,029	18,938,602	2,069,732	0	927,212,098

PLANT BRINGFORWARD

Account	2025	2025			2026		
	NOV 30	DECEMBER			JANUARY		
	Begin. Balance	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	1,932.08	0.00	0.00	1,932.08	0.00	0.00	1,932.08
351.00	3,294,840.04	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04
352.01	1,126,771.92	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92
352.02	1,072,322.09	0.00	0.00	1,072,322.09	0.00	0.00	1,072,322.09
352.10	206,940.78	0.00	0.00	206,940.78	0.00	0.00	206,940.78
353.00	385,797.21	0.00	0.00	385,797.21	0.00	0.00	385,797.21
354.00	947,637.58	0.00	0.00	947,637.58	0.00	0.00	947,637.58
354.10	449,536.94	85,920.30	0.00	535,457.24	13,891.77	0.00	549,349.01
355.00	104,476.92	0.00	0.00	104,476.92	0.00	0.00	104,476.92
374.40	11,008,773.01	45,101.02	11,275.26	11,042,598.77	25,541.43	249.96	11,067,890.24
374.50	3,233,313.87	0.00	0.00	3,233,313.87	0.00	0.00	3,233,313.87
375.34	7,887,261.80	138,933.03	34,733.26	7,991,461.57	38,045.17	372.33	8,029,134.41
375.60	85,565.04	0.00	0.00	85,565.04	0.00	0.00	85,565.04
375.70	51,614,653.44	21,781.40	0.00	51,636,434.84	0.00	0.00	51,636,434.84
375.80	16,515.16	0.00	0.00	16,515.16	0.00	0.00	16,515.16
376.00	3,256,429,736.99	43,425,567.89	10,856,391.98	3,288,998,912.90	12,243,885.33	119,824.11	3,301,122,974.12
378.00	178,796,716.00	3,921,752.30	980,438.08	181,738,030.22	882,319.78	8,634.77	182,611,715.23
379.10	119,158.02	0.00	0.00	119,158.02	0.00	0.00	119,158.02
380.00	928,587,037.16	11,943,369.44	2,985,842.36	937,544,564.24	3,396,344.05	33,238.13	940,907,670.16
381.00	50,186,336.91	1,232,566.13	308,141.53	51,110,761.51	364,062.56	3,562.88	51,471,261.19
381.10	27,384,527.15	217,511.67	54,377.92	27,547,660.90	64,246.34	628.74	27,611,278.50
382.00	54,955,718.61	435,143.29	108,785.82	55,282,076.08	174,202.24	1,704.82	55,454,573.50
383.00	20,499,491.83	225,309.18	56,327.29	20,668,473.72	120,731.37	1,181.53	20,788,023.56
384.00	3,509,385.47	4,767.93	1,191.98	3,512,961.42	2,700.17	26.43	3,515,635.16
385.00	9,513,777.69	186,978.94	46,744.74	9,654,011.89	49,364.15	483.10	9,702,892.94
387.00	136,698.14	0.00	0.00	136,698.14	0.00	0.00	136,698.14
387.40	18,812,522.43	0.00	0.00	18,812,522.43	0.00	0.00	18,812,522.43
387.50	2,201,371.95	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95
390.10	49,821.42	0.00	0.00	49,821.42	0.00	0.00	49,821.42
391.10	7,142,560.08	0.00	0.00	7,142,560.08	0.00	0.00	7,142,560.08
391.11	91,303.67	0.00	0.00	91,303.67	0.00	0.00	91,303.67
391.12	129,970.17	0.00	0.00	129,970.17	0.00	0.00	129,970.17
392.00	25,616.89	0.00	0.00	25,616.89	0.00	0.00	25,616.89
393.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
394.00	27,287,535.33	588,719.15	0.00	27,876,254.48	692,731.90	0.00	28,568,986.38
395.00	264,921.24	0.00	0.00	264,921.24	0.00	0.00	264,921.24
396.00	948,698.04	0.00	0.00	948,698.04	0.00	0.00	948,698.04
397.50	3,043,266.96	449,166.69	112,291.67	3,380,141.98	199,924.27	1,956.55	3,578,109.70
398.00	1,186,398.23	0.00	0.00	1,186,398.23	0.00	0.00	1,186,398.23
	0.00	0.00	0.00	0.00	0.00	0.00	0.00
303.00	79,879,820.12	1,449,436.22	432,816.27	80,896,440.07	492,694.67	987,926.67	80,401,208.07
303.60	21,383,249.19	979,822.30	158,959.76	22,204,111.73	23,711.76	0.00	22,227,823.49
305.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
362.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
362.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00
375.71	5,851,943.95	21,781.41	0.00	5,873,725.36	0.00	0.00	5,873,725.36
389.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NonDeprPlant	3,533,173.45	0.00	0.00	3,533,173.45	0.00	0.00	3,533,173.45
Total Plant	4,783,387,094.97	65,373,628.29	16,148,317.92	4,832,612,405.34	18,784,396.96	1,159,790.02	4,850,237,012.28

PLANT BRINGFORWARD

Account	2026			2026			2026		
	FEBRUARY			MARCH			APRIL		
	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	0.00	0.00	1,932.08	0.00	0.00	1,932.08	0.00	0.00	1,932.08
351.00	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04
352.01	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92
352.02	0.00	0.00	1,072,322.09	0.00	0.00	1,072,322.09	0.00	0.00	1,072,322.09
352.10	0.00	0.00	206,940.78	0.00	0.00	206,940.78	0.00	0.00	206,940.78
353.00	0.00	0.00	385,797.21	0.00	0.00	385,797.21	0.00	0.00	385,797.21
354.00	0.00	0.00	947,637.58	0.00	0.00	947,637.58	0.00	0.00	947,637.58
354.10	13,461.37	0.00	562,810.38	20,860.71	0.00	583,671.09	25,303.25	0.00	608,974.34
355.00	0.00	0.00	104,476.92	0.00	0.00	104,476.92	0.00	0.00	104,476.92
374.40	20,192.25	988.05	11,087,094.44	31,553.43	1,543.98	11,117,103.89	14,758.76	866.62	11,130,996.03
374.50	0.00	0.00	3,233,313.87	0.00	0.00	3,233,313.87	0.00	0.00	3,233,313.87
375.34	34,093.74	1,668.28	8,061,559.87	52,993.54	2,593.09	8,111,960.32	49,974.60	2,934.44	8,159,000.48
375.60	0.00	0.00	85,565.04	0.00	0.00	85,565.04	0.00	0.00	85,565.04
375.70	100,000.00	0.00	51,736,434.84	10,000.00	0.00	51,746,434.84	9,500.00	0.00	51,755,934.84
375.80	0.00	0.00	16,515.16	0.00	0.00	16,515.16	0.00	0.00	16,515.16
376.00	10,034,298.04	491,000.56	3,310,666,271.60	15,772,882.33	771,802.27	3,325,667,351.66	16,658,211.22	978,148.07	3,341,347,414.81
378.00	528,167.63	25,844.42	183,114,038.44	847,327.11	41,461.60	183,919,903.95	841,046.94	49,385.16	184,711,565.73
379.10	0.00	0.00	119,158.02	0.00	0.00	119,158.02	0.00	0.00	119,158.02
380.00	3,065,033.92	149,978.94	943,822,725.14	4,762,797.04	233,054.27	948,352,467.91	4,610,713.86	270,735.00	952,692,446.77
381.00	334,169.30	16,351.65	51,789,078.84	518,923.11	25,392.06	52,282,609.89	533,404.82	31,320.82	52,784,693.89
381.10	58,971.05	2,885.59	27,667,363.96	91,574.67	4,480.95	27,754,457.68	94,130.26	5,527.20	27,843,060.74
382.00	144,800.88	7,085.43	55,592,288.95	225,774.10	11,047.63	55,807,015.42	150,016.00	8,808.74	55,948,222.68
383.00	96,119.53	4,703.34	20,879,439.75	150,153.83	7,347.36	21,022,246.22	74,453.99	4,371.84	21,092,328.37
384.00	2,134.67	104.45	3,517,665.38	3,335.74	163.23	3,520,837.89	1,560.25	91.62	3,522,306.52
385.00	44,568.26	2,180.82	9,745,280.38	69,254.01	3,388.75	9,811,145.64	67,150.55	3,942.99	9,874,353.20
387.00	0.00	0.00	136,698.14	0.00	0.00	136,698.14	0.00	0.00	136,698.14
387.40	0.00	0.00	18,812,522.43	0.00	0.00	18,812,522.43	0.00	0.00	18,812,522.43
387.50	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95
390.10	0.00	0.00	49,821.42	0.00	0.00	49,821.42	0.00	0.00	49,821.42
391.10	0.00	0.00	7,142,560.08	0.00	0.00	7,142,560.08	0.00	0.00	7,142,560.08
391.11	0.00	0.00	91,303.67	0.00	0.00	91,303.67	0.00	0.00	91,303.67
391.12	0.00	0.00	129,970.17	0.00	0.00	129,970.17	0.00	0.00	129,970.17
392.00	0.00	0.00	25,616.89	0.00	0.00	25,616.89	0.00	0.00	25,616.89
393.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
394.00	495,376.03	0.00	29,064,362.41	865,759.51	0.00	29,930,121.92	546,831.64	0.00	30,476,953.56
395.00	0.00	0.00	264,921.24	0.00	0.00	264,921.24	0.00	0.00	264,921.24
396.00	0.00	0.00	948,698.04	0.00	0.00	948,698.04	0.00	0.00	948,698.04
397.50	142,966.84	6,995.69	3,714,080.85	249,860.51	12,226.23	3,951,715.13	157,817.07	9,266.81	4,100,265.39
398.00	0.00	0.00	1,186,398.23	0.00	0.00	1,186,398.23	0.00	0.00	1,186,398.23
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
303.00	1,261,872.24	59,126.44	81,603,953.87	461,628.68	697,569.64	81,368,012.91	446,190.49	3,913,380.87	77,900,822.53
303.60	27,646.53	0.00	22,255,470.02	30,973.95	153,635.68	22,132,808.29	29,938.09	156,243.54	22,006,502.84
305.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
362.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
362.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
375.71	100,000.00	0.00	5,973,725.36	10,000.00	0.00	5,983,725.36	9,500.00	0.00	5,993,225.36
389.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NonDeprPlant	0.00	0.00	3,533,173.45	0.00	0.00	3,533,173.45	0.00	0.00	3,533,173.45
Total Plant	16,503,872.28	768,913.66	4,865,971,970.90	24,175,652.27	1,965,706.74	4,888,181,916.43	24,320,501.79	5,435,023.72	4,907,067,394.50

PLANT BRINGFORWARD

Account	2026			2026			2026		
	MAY			JUNE			JULY		
	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	0.00	0.00	1,932.08	0.00	0.00	1,932.08	0.00	0.00	1,932.08
351.00	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04
352.01	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92
352.02	0.00	0.00	1,072,322.09	0.00	0.00	1,072,322.09	0.00	0.00	1,072,322.09
352.10	0.00	0.00	206,940.78	0.00	0.00	206,940.78	0.00	0.00	206,940.78
353.00	0.00	0.00	385,797.21	0.00	0.00	385,797.21	0.00	0.00	385,797.21
354.00	0.00	0.00	947,637.58	0.00	0.00	947,637.58	0.00	0.00	947,637.58
354.10	24,930.49	0.00	633,904.83	51,255.83	0.00	685,160.66	35,441.34	0.00	720,602.00
355.00	0.00	0.00	104,476.92	0.00	0.00	104,476.92	0.00	0.00	104,476.92
374.40	15,300.35	1,048.15	11,145,248.23	22,763.66	1,559.43	11,166,452.46	4,631.70	271.97	11,170,812.19
374.50	0.00	0.00	3,233,313.87	0.00	0.00	3,233,313.87	0.00	0.00	3,233,313.87
375.34	49,700.10	3,404.71	8,205,295.87	96,892.61	6,637.64	8,295,550.84	60,239.69	3,537.19	8,352,253.34
375.60	0.00	0.00	85,565.04	0.00	0.00	85,565.04	0.00	0.00	85,565.04
375.70	40,000.00	0.00	51,795,934.84	40,000.00	0.00	51,835,934.84	181,000.00	0.00	52,016,934.84
375.80	0.00	0.00	16,515.16	0.00	0.00	16,515.16	0.00	0.00	16,515.16
376.00	16,375,832.85	1,121,828.38	3,356,601,419.28	32,135,287.88	2,201,431.73	3,386,535,275.43	21,712,891.15	1,274,952.16	3,406,973,214.42
378.00	868,626.26	59,505.35	185,520,686.64	1,564,355.65	107,166.37	186,977,875.92	1,116,308.39	65,548.15	188,028,636.16
379.10	0.00	0.00	119,158.02	0.00	0.00	119,158.02	0.00	0.00	119,158.02
380.00	4,580,437.58	313,783.42	956,959,100.93	8,985,947.71	615,583.42	965,329,465.22	5,662,409.61	332,489.19	970,659,385.64
381.00	528,646.36	36,214.98	53,277,125.27	1,051,369.02	72,024.16	54,256,470.13	681,613.92	40,023.47	54,898,060.58
381.10	93,290.53	6,390.88	27,929,960.39	185,535.71	12,710.15	28,102,785.95	120,284.81	7,062.96	28,216,007.80
382.00	151,803.31	10,399.30	56,089,626.69	266,317.46	18,244.11	56,337,700.04	125,644.61	7,377.68	56,455,966.97
383.00	76,832.77	5,263.44	21,163,897.70	118,156.98	8,094.36	21,273,960.32	30,832.98	1,810.47	21,302,982.83
384.00	1,617.51	110.81	3,523,813.22	2,406.51	164.86	3,526,054.87	489.65	28.75	3,526,515.77
385.00	66,705.25	4,569.65	9,936,488.80	130,912.59	8,968.18	10,058,433.21	82,559.73	4,847.80	10,136,145.14
387.00	0.00	0.00	136,698.14	0.00	0.00	136,698.14	0.00	0.00	136,698.14
387.40	0.00	0.00	18,812,522.43	0.00	0.00	18,812,522.43	0.00	0.00	18,812,522.43
387.50	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95
390.10	0.00	0.00	49,821.42	0.00	0.00	49,821.42	0.00	0.00	49,821.42
391.10	0.00	0.00	7,142,560.08	0.00	0.00	7,142,560.08	0.00	0.00	7,142,560.08
391.11	0.00	0.00	91,303.67	0.00	0.00	91,303.67	0.00	0.00	91,303.67
391.12	0.00	0.00	129,970.17	0.00	0.00	129,970.17	0.00	0.00	129,970.17
392.00	0.00	0.00	25,616.89	0.00	0.00	25,616.89	0.00	0.00	25,616.89
393.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
394.00	459,777.10	0.00	30,936,730.66	718,801.45	0.00	31,655,532.11	427,784.38	0.00	32,083,316.49
395.00	0.00	0.00	264,921.24	0.00	0.00	264,921.24	0.00	0.00	264,921.24
396.00	0.00	0.00	948,698.04	0.00	0.00	948,698.04	0.00	0.00	948,698.04
397.50	132,692.90	9,090.14	4,223,868.15	207,448.02	14,211.25	4,417,104.92	123,459.71	7,249.39	4,533,315.24
398.00	0.00	0.00	1,186,398.23	0.00	0.00	1,186,398.23	0.00	0.00	1,186,398.23
	0.00	0.00		0.00	0.00		0.00	0.00	
303.00	486,700.05	3,942,327.29	74,445,195.29	644,596.11	1,805,625.86	73,284,165.54	1,391,522.35	477,408.15	74,198,279.74
303.60	32,656.16	0.00	22,039,159.00	43,250.53	2,790,958.20	19,291,451.33	36,445.29	0.00	19,327,896.62
305.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
362.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
362.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
375.71	40,000.00	0.00	6,033,225.36	40,000.00	0.00	6,073,225.36	181,000.00	0.00	6,254,225.36
389.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NonDeprPlant	0.00	0.00	3,533,173.45	0.00	0.00	3,533,173.45	0.00	0.00	3,533,173.45
Total Plant	24,025,549.57	5,513,936.50	4,925,579,007.57	46,305,297.72	7,663,379.72	4,964,220,925.57	31,974,559.31	2,222,607.33	4,993,972,877.55

PLANT BRINGFORWARD

Account	2026			2026			2026		
	AUGUST			SEPTEMBER			OCTOBER		
	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	0.00	0.00	1,932.08	0.00	0.00	1,932.08	0.00	0.00	1,932.08
351.00	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04
352.01	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92
352.02	0.00	0.00	1,072,322.09	0.00	0.00	1,072,322.09	0.00	0.00	1,072,322.09
352.10	0.00	0.00	206,940.78	0.00	0.00	206,940.78	0.00	0.00	206,940.78
353.00	0.00	0.00	385,797.21	0.00	0.00	385,797.21	0.00	0.00	385,797.21
354.00	0.00	0.00	947,637.58	0.00	0.00	947,637.58	0.00	0.00	947,637.58
354.10	69,116.94	0.00	789,718.94	27,152.80	0.00	816,871.74	53,189.40	0.00	870,061.14
355.00	0.00	0.00	104,476.92	0.00	0.00	104,476.92	0.00	0.00	104,476.92
374.40	36,880.69	2,526.52	11,205,166.36	12,621.67	1,235.21	11,216,552.82	49,502.51	3,875.63	11,262,179.70
374.50	0.00	0.00	3,233,313.87	0.00	0.00	3,233,313.87	0.00	0.00	3,233,313.87
375.34	134,419.06	9,208.39	8,477,464.01	51,671.16	5,056.77	8,524,078.40	116,291.53	9,104.65	8,631,265.28
375.60	0.00	0.00	85,565.04	0.00	0.00	85,565.04	0.00	0.00	85,565.04
375.70	0.00	0.00	52,016,934.84	0.00	0.00	52,016,934.84	0.00	0.00	52,016,934.84
375.80	0.00	0.00	16,515.16	0.00	0.00	16,515.16	0.00	0.00	16,515.16
376.00	44,805,605.02	3,069,413.31	3,448,709,406.13	18,494,390.68	1,809,943.48	3,465,393,853.33	37,929,257.61	2,969,540.93	3,500,353,570.01
378.00	2,444,163.43	167,437.71	190,305,361.88	1,297,686.43	126,997.38	191,476,050.93	2,676,901.16	209,578.78	193,943,373.31
379.10	0.00	0.00	119,158.02	0.00	0.00	119,158.02	0.00	0.00	119,158.02
380.00	12,424,053.55	851,111.27	982,232,327.92	4,788,217.40	468,596.29	986,551,949.03	10,608,662.24	830,568.76	996,330,042.51
381.00	1,442,996.51	98,852.65	56,242,204.44	559,260.88	54,731.76	56,746,733.56	1,196,721.74	93,693.22	57,849,762.08
381.10	254,646.44	17,444.58	28,453,209.66	98,693.10	9,658.55	28,542,244.21	211,186.18	16,534.10	28,736,896.29
382.00	391,692.46	26,832.94	56,820,826.49	144,044.83	14,096.87	56,950,774.45	412,662.86	32,308.02	57,331,129.29
383.00	187,651.55	12,855.09	21,477,779.29	65,170.03	6,377.83	21,536,571.49	241,124.54	18,878.02	21,758,818.01
384.00	3,898.92	267.10	3,530,147.59	1,334.33	130.58	3,531,351.34	5,233.26	409.72	3,536,174.88
385.00	180,963.98	12,396.96	10,304,712.16	69,754.21	6,826.46	10,367,639.91	154,398.56	12,088.10	10,509,950.37
387.00	0.00	0.00	136,698.14	0.00	0.00	136,698.14	0.00	0.00	136,698.14
387.40	0.00	0.00	18,812,522.43	0.00	0.00	18,812,522.43	0.00	0.00	18,812,522.43
387.50	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95
390.10	0.00	0.00	49,821.42	0.00	0.00	49,821.42	0.00	0.00	49,821.42
391.10	0.00	0.00	7,142,560.08	0.00	0.00	7,142,560.08	0.00	0.00	7,142,560.08
391.11	0.00	0.00	91,303.67	0.00	0.00	91,303.67	0.00	0.00	91,303.67
391.12	0.00	0.00	129,970.17	0.00	0.00	129,970.17	0.00	0.00	129,970.17
392.00	0.00	0.00	25,616.89	0.00	0.00	25,616.89	0.00	0.00	25,616.89
393.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
394.00	1,342,623.53	0.00	33,425,940.02	476,957.94	0.00	33,902,897.96	1,635,532.82	0.00	35,538,430.78
395.00	0.00	0.00	264,921.24	0.00	0.00	264,921.24	0.00	0.00	264,921.24
396.00	0.00	0.00	948,698.04	0.00	0.00	948,698.04	0.00	0.00	948,698.04
397.50	387,484.73	26,544.69	4,894,255.28	137,651.33	13,471.17	5,018,435.44	472,019.14	36,955.12	5,453,499.46
398.00	0.00	0.00	1,186,398.23	0.00	0.00	1,186,398.23	0.00	0.00	1,186,398.23
	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
303.00	833,232.31	212,324.97	74,819,187.08	697,481.58	421,691.47	75,094,977.19	1,014,245.12	179,146.36	75,930,075.95
303.60	55,907.47	817,972.01	18,565,832.08	46,798.99	0.00	18,612,631.07	68,052.91	9,049.74	18,671,634.24
305.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
362.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
362.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
375.71	0.00	0.00	6,254,225.36	0.00	0.00	6,254,225.36	0.00	0.00	6,254,225.36
389.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NonDeprPlant	0.00	0.00	3,533,173.45	0.00	0.00	3,533,173.45	0.00	0.00	3,533,173.45
Total Plant	64,995,336.59	5,325,188.19	5,053,643,025.95	26,968,887.36	2,938,813.82	5,077,673,099.49	56,844,981.58	4,421,731.15	5,130,096,349.92

PLANT BRINGFORWARD

Account	2026			2026		
	NOVEMBER			DECEMBER		
	Additions	Retirements	Ending Balance	Additions	Retirements	Ending Balance
350.20	0.00	0.00	1,932.08	0.00	0.00	1,932.08
351.00	0.00	0.00	3,294,840.04	0.00	0.00	3,294,840.04
352.01	0.00	0.00	1,126,771.92	0.00	0.00	1,126,771.92
352.02	0.00	0.00	1,072,322.09	0.00	0.00	1,072,322.09
352.10	0.00	0.00	206,940.78	0.00	0.00	206,940.78
353.00	0.00	0.00	385,797.21	0.00	0.00	385,797.21
354.00	0.00	0.00	947,637.58	0.00	0.00	947,637.58
354.10	31,803.08	0.00	901,864.22	62,101.06	0.00	963,965.28
355.00	0.00	0.00	104,476.92	0.00	0.00	104,476.92
374.40	46,755.86	5,948.46	11,302,987.10	81,518.76	19,944.47	11,364,561.39
374.50	0.00	0.00	3,233,313.87	0.00	0.00	3,233,313.87
375.34	79,970.51	10,174.15	8,701,061.64	150,206.75	36,749.75	8,814,518.64
375.60	0.00	0.00	85,565.04	0.00	0.00	85,565.04
375.70	0.00	0.00	52,016,934.84	21,781.40	0.00	52,038,716.24
375.80	0.00	0.00	16,515.16	0.00	0.00	16,515.16
376.00	24,015,233.98	3,055,309.15	3,521,313,494.84	47,393,043.65	11,595,236.06	3,557,111,302.43
378.00	1,578,050.00	200,765.51	195,320,657.80	3,484,273.50	852,466.33	197,952,464.97
379.10	0.00	0.00	119,158.02	0.00	0.00	119,158.02
380.00	7,194,193.65	915,272.60	1,002,608,963.56	13,562,793.09	3,318,288.41	1,012,853,468.24
381.00	785,613.22	99,948.69	58,535,426.61	1,494,106.01	365,549.68	59,663,982.94
381.10	138,637.62	17,638.00	28,857,895.91	263,665.76	64,508.77	29,057,052.90
382.00	337,099.35	42,887.06	57,625,341.58	606,737.41	148,445.07	58,083,633.92
383.00	222,739.95	28,337.82	21,953,220.14	390,153.09	95,455.30	22,247,917.93
384.00	4,942.90	628.85	3,540,488.93	8,617.93	2,108.47	3,546,998.39
385.00	104,614.21	13,309.42	10,601,255.16	197,268.37	48,263.90	10,750,259.63
387.00	0.00	0.00	136,698.14	0.00	0.00	136,698.14
387.40	0.00	0.00	18,812,522.43	0.00	0.00	18,812,522.43
387.50	0.00	0.00	2,201,371.95	0.00	0.00	2,201,371.95
390.10	0.00	0.00	49,821.42	0.00	0.00	49,821.42
391.10	0.00	0.00	7,142,560.08	0.00	0.00	7,142,560.08
391.11	0.00	0.00	91,303.67	0.00	24,427.00	66,876.67
391.12	0.00	0.00	129,970.17	0.00	0.00	129,970.17
392.00	0.00	0.00	25,616.89	0.00	0.00	25,616.89
393.00	0.00	0.00	0.00	0.00	0.00	0.00
394.00	1,326,183.33	0.00	36,864,614.11	2,770,038.85	186,888.81	39,447,764.15
395.00	0.00	0.00	264,921.24	0.00	0.00	264,921.24
396.00	0.00	0.00	948,698.04	0.00	0.00	948,698.04
397.50	382,740.05	48,693.64	5,787,545.87	799,440.60	195,592.05	6,391,394.42
398.00	0.00	0.00	1,186,398.23	0.00	6,122.60	1,180,275.63
	0.00	0.00		0.00	0.00	
303.00	794,854.59	108,893.97	76,616,036.57	1,933,032.91	1,860,113.84	76,688,955.64
303.60	2,040,048.41	34,080.36	20,677,602.29	979,822.30	118,441.18	21,538,983.41
305.00	0.00	0.00	0.00	0.00	0.00	0.00
362.00	0.00	0.00	0.00	0.00	0.00	0.00
362.10	0.00	0.00	0.00	0.00	0.00	0.00
375.71	0.00	0.00	6,254,225.36	21,781.41	0.00	6,276,006.77
389.20	0.00	0.00	0.00	0.00	0.00	0.00
NonDeprPlant	0.00	0.00	3,533,173.45	0.00	0.00	3,533,173.45
Total Plant	39,083,480.71	4,581,887.68	5,164,597,942.95	74,220,382.85	18,938,601.69	5,219,879,724.11

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

DIRECT TESTIMONY OF
KEVIN L. JOHNSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

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1 **I. Introduction**

2
3 **Q. Please state your name and business address.**

4 A. My name is Kevin L. Johnson. My business address is 290 West Nationwide
5 Boulevard, Columbus, Ohio 43215.

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

7 A. I am employed by NiSource Corporate Services Company (“NCSC”), a
8 management and services subsidiary of NiSource Inc. (“NiSource”). My current
9 title is Lead Regulatory Studies Analyst in the Regulatory Studies Department at
10 NCSC.

11 **Q. Please briefly describe your professional experience.**

12 A. I have over 20 years of experience working in various accounting, compliance, and
13 regulatory functions primarily supporting NiSource companies, including
14 Columbia Gas of Pennsylvania, Inc. (“Columbia” or “the Company”). In April
15 1999, I was hired by Columbia Gas of Ohio, Inc. (“COH”) as a Financial Analyst in
16 the Special Studies group, providing accounting support for the Columbia Gas
17 Distribution Companies. In May 2002, I was promoted to the position of
18 Accounting Manager of NCSC, overseeing its general books and records. From
19 March 2010 through June 2015, I was the Manager of Consolidation Accounting
20 and Securities and Exchange Commission Financial Reporting for NiSource,
21 ensuring accurate and timely financial statement preparation. In July 2015,
22 NiSource spun-off its gas transmission and storage business and created a new
23 standalone entity named Columbia Pipeline Group (“CPG”). I was named Director,

1 Sarbanes-Oxley (“SOX”) Compliance at CPG overseeing its overall SOX
2 compliance program until early 2017 when this role ended after the acquisition of
3 CPG by TC Energy. From mid-2017 until mid-2019, I was an Accounting Manager
4 at JPMorgan Chase. In June 2019, I rejoined NCSC in the Regulatory Studies
5 department as a Lead Regulatory Studies Analyst supporting various NiSource
6 companies.

7 **Q. Please describe your educational background.**

8 A. I graduated from The Ohio State University in 1999 with a Bachelor of Science
9 degree in Business Administration, majoring in Accounting. I am a Certified Public
10 Accountant and a member of the Ohio Society of Certified Public Accountants.

11 **Q. What are your responsibilities in your current position?**

12 A. My responsibilities as a Lead Regulatory Studies Analyst include providing support
13 for regulatory filings for several NiSource gas distribution companies, including,
14 Columbia, Columbia Gas of Maryland, Inc. (“CMD”), Columbia Gas of Kentucky,
15 Inc. (“CKY”), Columbia Gas of Virginia, Inc. (“CVA”), and COH.

16 **Q. Have you previously testified before this or any other regulatory**
17 **agency?**

18 A. I have presented testimony for Columbia before the Pennsylvania Public Utility
19 Commission (“Commission”) in Case Nos. R-2022-3031211 and R-2024-3046519 as
20 the Allocated Cost of Service and Rate Design witness and Case No. R-2008-2011621
21 supporting NCSC costs. I have presented testimony for CMD before the Public
22 Service Commission of Maryland in Case No. 9701 as the Allocated Cost of Service

1 and Rate Design witness and in Case No. 9644 as the Cash Working Capital witness.

2 I have presented testimony for CKY before the Kentucky Public Service Commission
3 in Case No. 2021-00183 as the Cash Working Capital, Allocated Cost of Service, and
4 Rate Design witness and in Case No. 2024-00092 as the Cash Working Capital
5 witness. I have presented testimony for CVA before the State Corporation
6 Commission of Virginia in Case No. PUR-2022-00036 as the Cash Working Capital
7 witness. I have also provided Allocated Cost of Service and Rate Design support to
8 witnesses in previous Columbia and CMD rate cases.

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

10 A. I am sponsoring Columbia's Allocated Cost of Service ("ACOS") studies and the
11 proposed rate design shown in Exhibit 103, Schedule 8. As required by Section 53.53
12 IV¹, Items 1 and 9, of the Commission's regulations, I prepared ACOS studies by rate
13 class at present and proposed rates (Item 1) and a cost analysis supporting minimum
14 charges for all rate schedules (Item 9). The studies and cost analysis are presented in
15 Exhibit 111. Item 10 of Section 53.53 IV requires a cost analysis supporting demand
16 charges. I did not prepare a cost analysis for demand charges because Columbia's
17 present and proposed tariffs do not contain distribution demand charges.

18 **Q. Please describe Exhibit No. 11.**

19 A. Exhibit No. 11 addresses the Commission's filing requirements regarding ACOS
20 studies as required by Section 53.53 IV. The Company's ACOS studies are
21 presented in Exhibit No. 111 and a detailed description of the methodologies are

¹ 52 Pa Code § 53.51 *et. seq.*

1 included in this testimony. The ACOS studies are based on the fully projected
2 future test year ending December 31, 2026.

3 **II. Allocated Cost of Service**

4 **Q. Are you responsible for the ACOS studies presented in Exhibit No. 111?**

5 A. Yes, I am.

6 **Q. Three ACOS studies are included in Exhibit No. 111. Is that correct?**

7 A. Yes.

8 **Q. Why did you conduct three ACOS studies?**

9 A. Columbia has filed two studies in its base rate proceedings since the early 1980s
10 that provide the outside limits of the possible allocations of mains to the various
11 classes of service. The customer-demand study (Exhibit No. 111, Schedule 1)
12 produces results that are generally more favorable to the industrial class, while the
13 peak and average study (Exhibit No. 111, Schedule 2) produces results that are
14 generally more favorable to the residential class. Columbia has in the past
15 submitted the results of two such studies as they provided a reasonable range of
16 returns for use as a guide in establishing appropriate rates. Columbia continues to
17 believe that the two studies provide the reasonable range of returns for use in
18 revenue allocation. However, Columbia recognizes this Commission's preference
19 for the use of the peak and average study and therefore, used the peak and average
20 study as the primary guide for the allocation of the revenue increase in this case.

21 **Q. What is the basis of the third study, and why did Columbia include it in**
22 **the filing?**

A. The third study, as presented in Exhibit No. 111, Schedule 3, is an average of the customer-demand study and the peak and average study. The average study with its equal weighting of the two studies, provides the Company, the parties and the Commission with another set of returns that can be used as a guide in revenue allocation. In other words, the average study serves as another tool that can be used by the parties to inform the revenue allocation in setting cost-based rates.

Q. Could you provide a list of the schedules and attachments you are sponsoring through your testimony?

A. Yes. Table KLJ-1 below lists all the schedules and attachments that I am sponsoring.

Table KLJ-1

<u>Schedule/Attachment</u>	<u>Description</u>
Exh. No. 11	ACOS Studies
Exh. No. 111, Schedule No. 1	Customer-Demand Study
Exh. No. 111, Schedule No. 2	Peak and Average Study
Exh. No. 111, Schedule No. 3	Average Study
Exh. No. 111, Schedule Nos. 5 & 6	Bill Comparisons
Exh. No. 103, Schedule No. 8	Proposed Revenue Allocation, Rates
Statement No. 6, Exhibit KLJ-1	Development of Allocation Factors
Statement No. 6, Exhibit KLJ-2	Calculation of Allocation Factors
Statement No. 6, Exhibit KLJ-3	Factor Selection and Rationale
Statement No. 6, Exhibit KLJ-4	Intra-Class Adjustment of Storage Carrying Costs
Statement No. 6, Exhibit KLJ-5	ACOS Study Return Results
Statement No. 6, Exhibit KLJ-6	Gas Procurement Charge Calc.
Statement No. 6, Exhibit KLJ-7	Residential and Small Commercial Energy Efficiency Rider Calculation

1 **Q. Could you briefly describe the format of the ACOS studies that you are**
2 **sponsoring?**

3 A. The format is generally identical for the three studies except for the peak and average
4 study, Exhibit No. 111, Schedule No. 2. It contains 30 pages, while the customer-
5 demand study in Exhibit No. 111, Schedule 1 and the average study in Exhibit No. 111,
6 Schedule 3 both contain 13 pages. The peak and average study contains the customer
7 charge studies, which I will discuss later in my testimony, and which are shown on
8 pages 14 through 30 of Exhibit No. 111, Schedule No. 2. The rates of return that are
9 shown on page 1 of each study are based on income generated using proposed rates,
10 with page 2 showing the rates of return generated using current rates. Both page 1
11 and page 2 summarize the same allocated cost of service with the exception of
12 forfeited discounts, income taxes and uncollectibles, which vary with the changes in
13 revenue as a result of the change in current rates to proposed rates. The allocation of
14 gross plant investment is shown on page 3, while page 4 contains the reserve for
15 depreciation and page 5 contains depreciation and amortization expenses. Revenue
16 by account and rate schedule is summarized on page 6 for both current and proposed
17 rates and pages 7 and 8 contain the allocation for operation and maintenance
18 ("O&M") expenses, while page 9 contains the allocation of taxes other than income.
19 Rate base is detailed by rate schedule on page 10, with page 11 calculating Federal
20 and Corporate Net Income taxes. The allocation factors are listed on pages 12 and 13.

21 **Q. How were the rate schedules grouped in allocating the cost of service?**

1 A. For residential and small general service, sales and delivery services were
2 combined, respectively; Residential Sales Service (“RSS”) and Residential
3 Distribution Service (“RDS”) were combined and presented in Column D of each
4 study, and Small General Sales Service (“SGSS”), Small Commercial Distribution
5 (“SCD”) and Small General Distribution Service (“SGDS”) were combined and
6 presented in Column E of each study for Commercial and Industrial (“C&I”)
7 customers whose annual usage is less than 6,440 therms. SGSS, SCD and SGDS
8 were combined and presented in Column F of each study for C&I customers whose
9 annual usage is greater than 6,440 therms but less than 64,400 therms. Because
10 essentially any customer can qualify and, therefore, switch between sales and
11 distribution services under these schedules, it is reasonable to conclude that
12 customer characteristics are the same for both types of services, i.e., size,
13 consumption patterns, heat sensitivity, human need requirement, etc. With no
14 long-term difference in the customers’ profiles, the distribution cost to provide
15 such service to these customers is the same whether the customer is a sales
16 customer or distribution customer. For the larger customers, the studies present
17 the cost of service for each rate schedule: Small Distribution Service and the lower
18 band of Large General Sales Service (“SDS/LGSS”) is presented in Column G of
19 each study for C&I customers whose annual usage is greater than 64,400 therms
20 but less than 540,000 therms. Large Distribution Service (“LDS”) and the upper
21 band of Large General Sales Service (“LGSS”) is presented in Column H of each
22 study for C&I customers whose annual usage is greater than 540,000 therms.

1 Main Line Sales Service (“MLS”) and Main Line Distribution Service (“MLDS”) are
2 combined and presented in Column I due to their unique characteristic of
3 proximity to an interstate pipeline. Costs and revenues attributable to customers
4 taking service under the Flexible Rate Provisions and Negotiated Contract Service
5 tariffs (combined and identified as “FLEX”) are presented in Column J².

6 **Q. How were Total Company O&M expenses determined by Federal**
7 **Energy Regulatory Commission (“FERC”) account in the allocated cost**
8 **of service studies?**

9 A. O&M expenses for the fully projected future test year presented in Exhibit 104 were
10 based on cost element data, i.e., labor, benefits, insurance, etc. The ACOS studies’
11 spreadsheets submitted in response to Standard Data Request No. GAS-COS-008
12 show a conversion of the forecasted O&M by description (cost element) to the
13 FERC account, based on allocation percentages representative of the historic test
14 year data (twelve months ending November 30, 2024).

15 **Q. How was the demand component for each class determined?**

16 A. The demand component by class was provided by NCSC’s Energy Supply and
17 Optimization Department and represents expected requirements under design day
18 conditions. I note that the calculation reflects design day total requirements and
19 thus, assumes suppliers will make deliveries necessary to meet customer
20 requirements.

² Per paragraph No. 46 of the Joint Petition for Partial Settlement at Docket No. R-2018-2647557.

1 **Q. Why were the MLS/MLDS customer groups excluded from the above-**
2 **described allocations of mains?**

3 A. Customers served under rate schedules MLS/MLDS were excluded from the
4 allocations of mains under all studies because these customers are served directly
5 from an interstate pipeline or are in close proximity to an interstate pipeline.
6 Accordingly, Columbia has little or no main investment associated with providing
7 service to these customers. An inventory of the mains investment in serving these
8 customers was made by studying the Company's plant records and maps on a
9 customer-by-customer basis. The mains investment cost was then directly assigned
10 to MLS/MLDS rate schedules. Therefore, it is appropriate to exclude them from the
11 allocation of mains and mains-related costs.

12 **Q. Since a significant portion of the Company's investment and expense is**
13 **related to mains and services, does the allocation of these items**
14 **significantly impact the studies?**

15 A. Yes, it does. Mains and services account for the majority of the Company's gross
16 plant investment and distribution O&M expenses, excluding gas costs. The
17 allocation of these items significantly influences the outcome of the studies. In
18 addition, many other elements of O&M expenses are allocated on plant-related
19 factors.

20 **Q. How are purchased gas costs allocated in the studies?**

1 A. Gas costs are directly assigned to each class at the pro forma levels determined by
2 Company witness Battig (Columbia Statement No. 3) in her Exhibit No. 103,
3 Schedule No.1, Pages 13 through 18.

4 **Q. Were there any other major O&M expense items that you directly**
5 **assigned?**

6 A. Yes. As shown on Page 8, Lines 8 and 16 of all three studies, I assigned recovery of
7 costs from the Company's Universal Services Program ("USP") and Energy
8 Efficiency Rider ("Rider EE") to the residential class. Under both current and
9 proposed rates, these costs are recoverable from the residential class, whether sales
10 or delivery service. Line 8 relates to the uncollectible component attributable to
11 low-income residential customers enrolled in the Company's Customer Assistance
12 Program ("CAP") and Line 16 relates to Rider EE which currently only applies to
13 the residential class.

14 **Q. How did you handle Uncollectibles related to unbundling?**

15 A. Columbia utilizes three systems to bill customers: 1) Distributive Information System
16 ("DIS") that bills monthly read customers for either sales or Choice transportation
17 service, 2) Gas Measurement Billing ("GMB") that bills monthly read customers for
18 either sales or Choice distribution service, and 3) Gas Transportation System ("GTS")
19 that bills customers for traditional (non-Choice) distribution service. Please note the
20 GMB and GTS billing systems do not bill residential customers. Because DIS billed
21 net charge-offs are accounted for in the Company's accounting reports by customer
22 class, the residential net charge-offs were assigned to the residential class. The DIS

1 billed commercial net charge-offs were allocated between the SGSS1/SCD1/SGDS1
2 and SGSS2/SCD2/ SGDS2 rate classes based on DIS billed revenue within each class.
3 The portion of Account 904 related to the GMB and GTS billing systems and the
4 COVID-19 amortization was allocated to GMB and GTS billed customers by rate class
5 based on their GMB/GTS revenues.

6 **Q. Please describe how you allocated plant Account 380 - Services and the**
7 **related O&M accounts.**

8 A. First, I identified the services related to MLS/MLDS and directly assigned them. The
9 remaining investment in Account 380 - Services and the related O&M accounts were
10 based on an actual assignment of services installed on customers' premises.
11 Individual customer services were identified by size from the Company's DIS billing
12 system and accumulated by customer class and rate schedule. Based on the historic
13 test year per book data, the average unit price per size of pipe was determined and
14 applied to the number of services under each rate schedule based on pipe size. The
15 resulting values, by rate schedule, were converted to percentages and used to allocate
16 service investment and related expenses.

17 **Q. Please describe how you allocated plant Account 381 – Meters and**
18 **Account 382 – Meter Installations in the studies.**

19 A. First, I identified the services related to MLS/MLDS and directly assigned them. I
20 assigned meters to the various rate classes based on an actual inventory of meters
21 installed on customers' premises. Columbia recognizes four separate pressure
22 groups for meters based on the meter's maximum cubic feet per hour gas flow

1 (“CFH”), 0-500 CFH, 501-1000 CFH, 1001-1,500 CFH, and over 1,500 CFH. Each
2 meter type varies in cost as the size increases. Individual installed meters as identified
3 on DIS were summarized by the four pressure groups. The capitalized property
4 investment as identified on the Company’s books and records for the four pressure
5 groups was divided by the number of meters as reflected on the Company’s books
6 and records as of November 30, 2024, to develop a cost per meter for each group of
7 meters. The costs per meter were multiplied by the identified installed meters in DIS
8 to determine the investment for each rate class. The percentages were developed for
9 Account 381 and used for assigning Account 381 Meters as well as the investment in
10 Account 382 Meter Installations.

11 **Q. Please describe how you allocated plant accounts 383 – House**
12 **Regulators and 384 – House Regulator Installations.**

13 A. Both of these accounts contain costs that are directly associated with the cost of house
14 regulators. These regulators are installed where the distribution lines are
15 transporting gas at intermediate, medium, or high pressure. Recognizing this fact
16 and understanding, therefore, that customers being served by low pressure lines do
17 not require house regulators, I developed an allocation factor that excludes
18 customers served from low pressure lines from the total. The allocation factor uses
19 total number of customers, grouped by rate class, as assigned in DIS. The resulting
20 allocation percentages are then applied to the total capitalized property investment,
21 as identified on the Company’s books and records to determine the cost of house
22 regulators for each applicable rate class.

1 **Q. Please describe how you allocated plant Account 385 – Industrial**
2 **Measurement & Regulation (“M&R”) Equipment in the studies.**

3 A. Using data retrieved from DIS, I obtained, for each active customer who has an M&R
4 Station assigned to them, each station’s rate schedule and station number. Then, I
5 cross-referenced the station identification numbers to the Company’s plant
6 accounting records in order to identify the costs of each station. Then, I grouped
7 these costs into the corresponding rate classes (excluding MLS/MLDS) and used the
8 resulting totals as the basis for allocating all M & R plant.

9 **Q. Do you provide a more complete description of how these factors were**
10 **developed and the related calculations?**

11 A. Yes. In Exhibit KLJ-1 attached to this testimony, entitled “Development of
12 Allocation Factors”, I provide a description for all allocation factors used for the
13 studies. In Exhibit KLJ-2, I include all calculations of all allocation factors. And
14 in Exhibit KLJ-3, I provide the rationale for factor selection, by account, as it
15 pertains to the various categories of rate base and expense.

16 **Q. Did you prepare a study in support of the Company’s minimum or system**
17 **charges?**

18 A. Yes. I prepared two studies in support of the Company’s minimum or system charges.
19 They are contained in Exhibit No. 111, Schedule 2, pages 14 through 30.

20 **Q. Please describe the two studies.**

21 A. The study included in Exhibit 111, Schedule No. 2, pages 14 through 22 contains the
22 Company’s traditional customer charge study based on the customer-demand ACOS

1 study and includes the customer portion of mains costs. Columbia has used this
2 method in support of its customer charges in its previous general rate case filings.

3 The study presented on pages 23 through 30 of Schedule No. 2 is similar but excludes
4 the customer component of mains and other operations.

5 **Q. Why did you present the study excluding the customer component of**
6 **mains?**

7 A. I am aware that there have been disagreements concerning the inclusion of any mains
8 costs as a customer component. Therefore, I included the alternative calculation
9 excluding the customer component of mains. I also used the alternative study that
10 excludes all mains costs to establish a minimum customer cost benchmark for
11 determination of Columbia's customer charges.

12 **Q. Why does the Company believe a customer component of mains should**
13 **be included in a minimum system customer charge study?**

14 A. The allocation of a portion of distribution mains costs on a customer basis is
15 appropriate because of the way the distribution system is designed. Customer-
16 related costs include, at a minimum, the cost incurred by the Company to extend its
17 existing distribution system using a minimum size pipe (2" diameter) to attach a
18 customer to the distribution system. Simply stated, the customer component of
19 mains calculated in the ACOS represents a minimum fixed cost investment in mains
20 to attach a customer to the distribution system and therefore, has a direct
21 relationship to the number of customers served by the Company. At a minimum,
22 fixed costs that have a direct relationship to the number of customers served by the

1 Company should be recovered equally from all customers within a rate class, and that
2 is what a customer charge is designed to do. I discuss the Company's proposed
3 customer charges later in my testimony.

4 **Q. Did you prepare a study supporting the intra-class adjustment of storage**
5 **costs between the SGDS1 and the SGSS1/SCD1 classes and between the**
6 **SGDS2 and the SGSS2/SCD2 classes?**

7 A. Yes. I prepared a study, attached to this testimony as Exhibit KLJ-4, supporting the
8 intra-class adjustment of storage costs from the SGDS1 and SGDS2 classes to the
9 SGSS1, SGSS2, SCD1 and SCD2 classes. This adjustment is made because SGDS1 and
10 SGDS2 customers are not priority customers for whom Columbia purchases gas in
11 storage to serve.

12 **Q. Please describe this study.**

13 A. The study calculates the storage carrying costs, by rate class, by applying the
14 proposed pre-tax rate of return (Line 6) to the allocated storage balances (Line 3) and
15 utilizing Allocation Factor No. 25. The resulting storage carrying costs for the
16 SGS1/SGDS1 class and the SGS2/SGDS2 class (Line 7) includes costs that would,
17 without an adjustment, be assigned entirely to the SGDS1 class (Line 15) and SGDS2
18 class (Line 22). These costs are assigned to the SGSS1 and SCD1 classes and the
19 SGSS2 and SCD2 classes ratably, using a factor derived from their projected
20 throughput (Lines 13 & 14 under the heading "Ratio" for the SGSS1 and SCD1 classes
21 and Lines 20 & 21 for the SGSS2 and SCD2 classes). No other intra-class adjustments
22 are being supported or shown on this exhibit.

III. Revenue Allocation and Rate Design

a. Revenue Allocation

Q. Please describe the rate design principles that the Company considered when developing the proposed revenue allocation and rates.

A. The principles that were used to guide the development of the Company's rate design include: efficiency, simplicity, continuity, fairness, and earnings stability. An efficient rate design provides accurate price signals and thus, an accurate basis for consumers' decisions and provides the Company a reasonable opportunity to recover the cost of providing service. A simple rate structure is one that is understood by customers. The goal of rate continuity seeks gradual changes to rate design that will allow customers to adjust their consumption patterns, as needed. A fair rate design will consider the results of the allocated cost of service study in determining customer classes' total revenue responsibility. Finally, earnings stability means that the Company's earnings resulting from its rates should not vary significantly over the period of a few years.

Q. Please state the basis for the Company's proposed revenue allocation among the rate classes.

A. Consistent with the goal of continuity, Columbia seeks to move base rates closer to the allocated cost of service for each customer class gradually, so as to avoid rate shock to any particular rate class. The cost to serve each rate class is defined through the allocated cost of service study.

1 **Q. How were the results of the cost allocation studies used in designing the**
2 **proposed revenue requirements and rates?**

3 A. The cost allocation studies were used as a guide for assigning additional revenue
4 responsibility to customer groups. The peak and average study and the customer
5 demand study provide information about class cost relationships and help establish
6 a “zone of reasonableness” from which an appropriate revenue allocation and rate
7 design can be derived. For this case, Columbia used the peak and average study as
8 the primary study to establish class rates of return at current and proposed rates. The
9 peak and average study was given primary consideration given the Commission’s
10 ruling on the matter in Columbia’s 2020 base rate case. However, Columbia believes
11 the results from the other two studies can still be useful as other reference points in
12 guiding the allocation of the proposed revenue increase. The results of the cost
13 allocation studies support the Company’s proposed rate schedules. Details
14 concerning the application of the cost study results in the proposed rate design are
15 provided later in this testimony.

16 **Q. What are the results of the allocated cost of service studies at current**
17 **rates?**

18 A. Exhibit KLJ-5, attached to my testimony, shows the class-level return indices for each
19 of the ACOS studies. Return indices compare individual class returns to the overall
20 total Company return. A return index is calculated by dividing the class return by the
21 total Company return. The total Company return index will always be 1.00. The
22 closer an individual class’s return is to the total Company return, the closer its index

1 will be to 1.00 and to parity. The term “parity” in this context means that the class
2 return and the total Company return are equal.

3 The return index for the residential class ranges from 0.74 under the
4 Customer/Demand study to 1.19 under the Peak & Average study. The average ACOS
5 study produces a residential return index of 0.93.

6 The SGS1/SCD1/SGD1 return indices are 1.11 for the Peak & Average study,
7 1.16 for the Customer/Demand study and 1.13 for the average ACOS study.

8 The SGS2/SCD2/SGD2 return indices are 1.12 for the Peak & Average study,
9 2.49 for the Customer/Demand study and 1.62 for the average ACOS study.

10 The SDS/LGSS return indices are 1.14 for the Peak & Average study, 3.90 for
11 the Customer/Demand study and 1.92 for the average ACOS study.

12 The LDS/LGSS return indices are 0.40 for the Peak & Average study, 2.87 for
13 the Customer/Demand study, and 0.97 for the average ACOS study.

14 The return index for the MLDS class indicates that, by directly assigning
15 mains investment, the return is the same under each of the three ACOS studies
16 showing a return that is above parity with a return index of 38.05.

17 The FLEX return indices are -0.53 for the Peak & Average study, -0.23 for the
18 Customer/Demand study, and -0.46 for the average ACOS study.

19 **Q. What is the primary goal of Columbia’s class revenue allocation?**

20 A. The primary goal in Columbia’s approach to revenue allocation is to maintain a
21 movement toward parity among the various rate classes, consistent with Commission
22 decisions in previous Company rate cases. Movement toward parity, through a goal

of equal rates of return by class, is a way of assuring that the revenue allocation process takes into account the overall Company return and the relative returns by rate class. Each class's revenue increase is determined within the context of other rate class returns so that, over time, interclass returns remain close to one another rather than diverging. Maintaining a movement toward parity is a way to minimize potential cross-subsidization between classes.

Q. Do the Company's proposed rate increases for the various rate classes reflect the principle of gradualism?

A. Yes. First, Columbia's proposed rate increases for the various rate classes move the unitized returns toward parity (unitized return of 1.00) for each of the rate classes but with no rate class yet reaching parity. Second, the range of base rate revenue increase percentages for any class does not exceed 1.5 times the total system average increase of 16.73% (see Exhibit 103, Schedule No. 8, Page 1, Lines 20 through 37).

Q. Please describe the Company's proposed revenue allocation.

A. Columbia's allocation of the proposed base rate revenue increase, which is shown in Exhibit 103, Schedule No. 8, Page 4, Line 19, reflects the following allocations: 66.85% of the overall increase is applied to the residential class; 9.65% of the overall increase is applied to the SGS1/SCD1/SGDS1 class; 10.93% of the overall increase is applied to the SGS2/SCD2/SGDS2 class; 6.84% of the overall increase is applied to the SDS/LGS class; 5.73% of the overall increase is applied to the LDS/LGS class; 0.00% of the overall increase is applied to MLDS customers; and 0.00% of the overall increase is applied to the FLEX customers.

Exhibit 103, Schedule 8, Page 4, Lines 5 and 6 shows the movement toward parity produced by Columbia's proposed revenue allocation using the peak and average ACOS Study. The movement toward parity (unitized return of 1.00) measures each class's return versus the total Company return under current and proposed rates.

Q. Please explain why the revenue allocation to FLEX customers was limited to the revenue generated by increased customer charges.

A. A FLEX agreement is an individually negotiated contract with a customer who has provided a sworn affidavit that a lower rate is required to meet competition from an alternate fuel. Per the Flexible Rate Provisions of Columbia's tariff, the customer charge is not eligible for downward adjustment and is not negotiable. The customer charges that FLEX customers are charged are set under the rate schedule in which the customer is receiving service.³.

Q. Do FLEX rate agreements benefit Columbia's non-flex customers?

A. Yes. Revenue collected from FLEX rate customers contributes to the recovery of the Company's fixed costs. Absent FLEX rates, the Company may lose these customers to alternative fuels. Without the revenues from FLEX rate customers, the Company's non-flex customers would be assigned additional fixed cost recovery responsibility, and their rates would increase.

Q. Other than the ACOS studies, what guidelines or criteria have you considered in the design of the Company's rates?

³ Columbia Gas of Pennsylvania Tariff, Supplement No. 221 to Tariff Gas – Pa. PUC. No. 9 Sixth Revised Sheet No. 68.

1 A. There are a number of criteria that I considered in the design of rates, including the
2 following:

3 First, the design of Columbia's rates recognizes that rates must be just and
4 reasonable and must not be unduly discriminatory. Columbia's proposed rate design
5 also attempts to minimize cross-class subsidies.

6 Second, where rates require adjustment to achieve proper cost recovery,
7 customer impact considerations have been factored into the rate design process. For
8 instance, Columbia's proposed rate design moves each of the rate classes toward
9 parity (unitized return of 1.00 and a total Company required rate of return of 8.55%)
10 but recognizes a move to full parity of 1.00 in this case would not be consistent with
11 the principle of gradualism.

12 Third, Columbia's proposed rate design provides for recovery of fixed costs
13 through the customer charge at least proportional to the percentage recovery of fixed
14 costs in current rates. In the case of the residential class, where the proportion of
15 fixed costs has eroded since the 2012 base rate case, Columbia's proposed rate design
16 provides for recovery of an increasing proportion of fixed costs through the customer
17 charge.

18 **b. Customer Charge Rate Design**

19 **Q. What are the new base rates proposed for residential customers?**

20 A. Columbia proposes to increase the monthly residential customer charge from
21 \$17.25 to \$31.97. The remaining residential revenue increase was assigned to the
22 volumetric charge for a resulting rate of \$10.4458 per Dth.

1 **Q. How did Columbia determine a residential customer charge of \$31.97?**

2 A. Exhibit No. 111, Schedule 2, pages 16 and 25, show the range of minimum monthly
3 customer-based costs, both including and excluding distribution mains costs, for the
4 residential class. The Company is proposing a monthly customer charge of \$31.97 to
5 update rates to be more cost-based, to better reflect the Company's cost of providing
6 natural gas distribution service to its customers by increasing the recovery of
7 customer and demand-related costs through fixed charges. Additional discussion
8 regarding the Company's rate design strategy is detailed in Company witness Taylor's
9 Direct Testimony (Columbia Statement 17).

10 **Q. Describe the new base rates proposed for Small General Service**
11 **customers consuming less than or equal to 6,440 therms annually.**

12 A. Columbia proposes to increase the customer charge from \$33.00 to \$39.00. The
13 increased customer charge is proportional to the overall base revenue increase for
14 the rate class. The remaining revenue requirement for this customer class would
15 be recovered through the volumetric rates. Exhibit No. 111, Schedule No. 2, pages
16 16 and 25, show that the minimum customer costs for this rate class range from
17 \$33.13 (excluding mains) to \$87.76 (including mains). Columbia's customer
18 charge proposal of \$39.00 falls near the low end of the range of customer-based
19 costs. The remaining revenue is recovered through the volumetric base rates of
20 \$9.5455/Dth for SGSS1/SCD1 service and \$9.4172/Dth for SGDS1 service.

21 **Q. What are the customer-based costs for the Small General Service**
22 **customers using between 6,440 and 64,400 therms annually?**

1 A. The proposed SGSS2/SCD2/SGDS2 customer charge for customers whose annual
2 usage is between 6,440 therms and 64,400 therms is \$75.00. The increased
3 customer charge is proportional to the overall base revenue increase for the rate class.
4 The remaining revenue requirement for this customer class would be recovered
5 through the volumetric rates. The volumetric charge will be \$8.1187/Dth for
6 SGSS/SCD service and \$7.9903/Dth for SGDS service.

7 **Q. Please explain why the SGDS customers in the two rate classes above**
8 **have a different volumetric charge than the SGSS and SCD customers in**
9 **those rate classes.**

10 A. Consistent with previous base rate proceedings, Columbia re-allocated the storage
11 working capital costs assigned to the SGSS/SCD/SGDS classes, as a whole, through
12 the ACOS to SGSS/SCD classes only. As shown on Exhibit KLJ-4, Columbia has re-
13 allocated \$300,249 of storage working capital costs from the SGDS class to
14 SGSS/SCD. This intra-class re-allocation is shown on Lines 16 of Exhibit 103,
15 Schedule 8, Pages 6 and 7. As a result, the Company charges a different volumetric
16 base rate to the SGSS and SCD customers than to the SGDS customers, and that
17 principle will not change under proposed rates.

18 **Q. Please summarize Columbia's SDS/LGSS rate design proposal.**

19 A. The proposed SDS/LGSS customer charge for customers whose annual usage is
20 between 64,400 therms and 110,000 therms is \$358.00, and the proposed
21 customer charge for customers whose annual usage is between 110,000 therms
22 and 540,000 therms is \$1,623.00. The increase in customer charges is

proportional to the overall base revenue increase for the rate class. The remaining revenue requirement for this customer class would be recovered through the volumetric rates.

The volumetric base rate will be \$6.1188/Dth for SDS/LGSS customers whose annual usage is between 64,400 therms and 110,000 therms and \$5.7208/Dth for SDS/LGSS for customers whose annual usage is between 110,000 therms and 540,000 therms.

Q. Please summarize Columbia's LDS/LGSS rate design proposal.

A. Table KLJ-2 below shows the proposed customer charges for the LDS/LGSS rate class, which reflect an increase proportional to the base revenue increase for the rate class.

Table KLJ-2

Annual Usage Levels	Proposed Cust. Charge
> 540,000 to ≤ 1,074,000 Therms	\$4,252.00
> 1,074,000 to ≤ 3,400,000 Therms	\$6,614.00
> 3,400,000 to ≤ 7,500,000 Therms	\$12,754.00
> 7,500,000 Therms	\$18,895.00

Q. How is the LDS/LGSS volumetric based rate revenue requirement shown in Exhibit 103, Schedule 8, Page 8, Line 26 spread among the LDS/LGSS annual usage groups?

A. The volumetric base revenue requirement is split among the LDS/LGSS annual usage groups proportionately based on revenue produced from current volumetric base rates. (See Exhibit 103, Schedule 8, Page 8, Lines 28 through 31).

1 **IV. Revenue Proof and Bill Comparisons**

2 **Q. Please provide a proof of the Fully Projected Future Test Year (“FPFTY”)**
3 **base revenue requirement by rate schedule.**

4 A. Refer to Exhibit No. 103, Schedule No. 8.

5 **Q. What are the class-level bill impacts resulting from the Company’s**
6 **proposal?**

7 A. The class average bill impacts are shown on Exhibit No. 103, Schedule No. 8, Page 1,
8 column 7.

9 **Q. Is the Company providing graphs of the bill impacts?**

10 A. Yes. Please refer to Exhibit No. 111, Schedule No. 5, pages 1-9. Graphs depicting
11 Residential Sales Service are shown on page 1, and pages 2 through 9 provide graphs
12 for C&I customers.

13 **Q. What is the range of bill impacts for residential customers?**

14 A. Please refer to Exhibit No. 111, Schedule No. 6, page 1 that shows monthly bill impacts
15 for residential customers at various usage levels.

16 **Q. Has the Company performed bill impact analyses at various usage levels**
17 **for C&I customers?**

18 A. Yes. Refer to Exhibit No. 111, Schedule No. 6, pages 2 through 9. These pages provide
19 monthly bill impacts for Small General Sales Service and Large General Sales Service
20 customers at various usage levels.

21 **V. Other Rate Design Items**

22 **Q. Is Columbia proposing any changes to its current Weather**

Normalization Adjustment (“WNA”) mechanism?

A. Yes. Please see Columbia witness Taylor’s Direct Testimony (Columbia Statement No. 17) detailing the Company’s request to the Commission to approve the current pilot WNA mechanism as a permanent program.

Q. Is Columbia proposing a Revenue Normalization Adjustment (“RNA”) mechanism in this proceeding?

A. Yes. Please see Columbia witness Taylor’s Direct Testimony (Columbia Statement No. 17) detailing the Company’s proposal to implement an RNA mechanism for non-CAP residential and C&I customers.

Q. Did you prepare any other calculations?

A. Yes. I prepared the Gas Procurement Charge calculation as detailed in Exhibit KLJ-6 attached to my testimony.

Q. Did you propose making an adjustment to the Gas Procurement Charge?

A. No. Exhibit KLJ-6 shows the calculation of the Gas Procurement Charge in the 2021 base rate case. Similar to the 2022 and 2024 base rate cases, since the overall fundamentals of the Gas Procurement process did not change, the Company elected not to change the Gas Procurement Charge, but instead keep it at the 2021 calculated rate of \$0.00113 per/therm.

Q. Do you have any other rate calculations you would like to discuss?

A. Yes. As noted in Columbia witness Nunley’s Direct Testimony (Columbia Statement No. 13), Columbia is proposing the Phase II Three-Year Energy

1 Efficiency Plan (“EE Plan Rider” or “Plan”) which will expand the measure offerings
2 in the Residential Prescriptive program to provide customers with more natural gas
3 saving opportunities and the addition of a Small Commercial (“SC”) program. The SC
4 program will provide natural gas saving opportunities through equipment rebates to
5 small commercial customers by providing rebates for installing energy efficient
6 equipment for heating, water heating, steam process, commercial cooking and
7 dishwashing, and controls, as well as rebates for making improvements to the
8 building shell through insulation and air sealing.

9 In Exhibit KLJ-7 attached to my testimony, I have prepared the calculation
10 of the residential EE Plan Rider that will be billed to all residential customers
11 (excluding CAP customers). Based on the 2026 Program Costs, the Residential EE
12 Plan Rider rate is calculated at \$0.00634 per/therm. In addition, I have calculated
13 the SC Energy Efficiency Plan Rider rate that will be billed to all Small Commercial
14 customers, which includes the Small General Sales Service, Small Commercial
15 Distribution (Choice), and Small General Distribution Service customers. Based on
16 the 2026 Program Costs, the SC EE Plan Rider rate is calculated at \$0.00343
17 per/therm.

18 This Phase II Three-Year Energy Efficiency Plan update is not included in
19 the Company’s base rate revenue requirement in this case but is being submitted
20 as a separate request. However, the impact of the EE Plan Rider is shown on the
21 residential customer bill comparisons detailed in Exhibit No. 111, Schedule 6, Page

1 1, and the small commercial customer bill comparisons detailed in Exhibit No. 111,
2 Schedule 6, Pages 2 & 3.

3 **Q. Did you make any adjustments to the Company's State Tax Adjustment**
4 **Surcharge ("STAS")?**

5 A. No. The STAS remains at \$0 in the Company's FPFTY.

6 **Q. Does this complete your prepared Direct Testimony?**

7 A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Direct Assignment

“Direct Assignment” refers to a specific identification and isolation of plant and/or expenses based on Columbia’s accounting records and incurred exclusively to serve a specific customer or group of customers. Instances of the use of direct assignments in the study can be identified by the omission of an allocation factor number (generally in column c) and the use of the term “direct” immediately after the account number. The operative principle is to utilize direct assignment of plant and expenses wherever practicable and to allocate when accounting records do not indicate class categorization.

Factor No. 1 - Design Day

The quantities contained in Factor No. 1 represent the total demand projected to occur at Columbia’s design peak day. See Exhibit KLJ-2, Page 1.

Factor No. 2- Throughput Excluding Transportation

Throughput quantities, excluding transportation, for the twelve months ending December 31, 2026, are the basis for Factor No. 2. See Exhibit KLJ-2, Page 2.

Factor No. 3- Throughput Excluding MDS

Factor No. 3 represents the throughput quantities excluding MDS quantities for the twelve months ending December 31, 2026. See Exhibit KLJ-2, Page 2.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 4- Gas Purchase Expense

Factor No. 4 is based on gas cost assigned to each rate schedule for the twelve months ending December 31, 2026 using the applicable Gas Cost Recovery (“GCR”) rates. See Exhibit KLJ-2, Page 3.

Factor No. 5 - Composite of Factors No. 1 and Throughput

Factor No. 5 combines design day quantities included in Factor No. 1 and throughput quantities for the historic test year ended November 30, 2024 to produce a composite Factor No. 5. Factor No. 5 was used to allocate mains and mains related accounts for the Peak and Average Study. Please see Exhibit KLJ-2 Page 4 for the detail development of Factor No. 5.

Factor No. 6 - Average Number of Customers

Customers for each month of the twelve months ending December 31, 2026 were averaged and used to develop Factor No. 6. See Exhibit KLJ-2, Page 5.

Factor No. 7 – Current DIS Revenue

Factor No. 7 reflects gross charge-offs recorded during the twelve months ending November 30, 2024 to small usage customers through the Company’s Distributive Information System (“DIS”). See Exhibit KLJ-2, Page 6.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 8 – Current GMB/GTS

Factor No. 8 reflects revenue to be billed during the twelve months ending December 31, 2026 to larger sales usage and transportation customers through the Company's Gas Measurement Billing and General Transportation Systems. See Exhibit KLJ-2, Page 7.

Factor No. 9 – Customer Deposits

Factor No. 9 represents customer security deposits collected from customers by class as of November 30, 2024. See Exhibit KLJ-2, Page 8.

Factor No. 10 - Forfeited Discounts

Factor No. 10 is based on the amount of forfeited discounts billed to customers during the twelve months ended November 30, 2024. See Exhibit KLJ-2, Page 9.

Factor No. 11 - Distribution Plant Excluding Other

Factor No. 11 ratios are based on the spread of distribution plant dollars, excluding gas plant accounts 375.70, 375.71, and 387, to the customer groups resulting from the application of the various allocation factors to each gas plant account. The allocated dollars are aggregated and reduced to percentages to produce Factor No. 11. See Exhibit KLJ-2, Page 10.

Factor No. 12 - Gross Plant

Factor No. 12 ratios are based on the spread of total plant dollars to the customer groups resulting from the application of the various allocation factors to each gas plant

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

account. The allocated dollars are aggregated and reduced to percentages to produce Factor No. 12. See Exhibit KLJ-2, Page 13.

Factor No. 13 – Mains – Account 376

Factor No. 13 reflects the relationship based on the spread of dollars in account 376 Mains among all customer classes that resulted from allocating the Mains using composite Factor No. 5 for the Demand-Commodity Study and Factor No. 20 for the Customer-Demand Study for classes that could not be directly assigned. The dollars are aggregated and reduced to percentages to produce Factor No. 13. See Exhibit KLJ-2, Page 14.

Factor No. 14 – Composite Direct Plant – Accts 376 & 380

Factor No. 14 reflects the relationship based on the spread of dollars in accounts 376 Mains and 380 Services among all customer classes resulting from the application of the appropriate account allocation factor. The allocated dollars in each account are aggregated and reduced to percentages to produce Factor No. 14. See Exhibit KLJ-2, Page 15.

Factor No. 15 – Direct Assignment - Services

Factor No. 15 – reflects Services – Account 380 assigned by rate schedule based on an actual assignment of services installed on customers' premises. Individual customer services were identified by size kind from DIS and accumulated by customer class and rate schedule. Based on the historic test year per book data, average unit prices by service size were developed from the data and applied to the number of services under each rate schedule. The resulting values, by rate schedule were converted to

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

percentages and used to allocate service investment and related expenses. See Exhibit KLJ-2, Page 18.

Factor No. 16 – Direct Assignment – Meters

Meters were assigned to the various classes of customers based on meters installed on customers' premises. Columbia recognizes four separate pressure groups for meters. Each varies in cost as the size changes. Individually installed meters as identified in DIS were summarized by the four pressure groups. The capitalized property investment, as identified on the Company's books and records for the four pressure groups, was divided by the number of installed meters as reflected on the Company's books and records to develop a cost per meter for each group of meters. The costs per meter were multiplied by the identified installed meters in DIS to determine the investment for each customer class. The percentages were developed for account 381 and used for assigning account 381 Meters as well as the investment in account 382 Meter Installations since these costs are incurred in direct relation with meters. See Exhibit KLJ-2, Page 19.

Factor No. 17 – Direct Assignment - Ind M&R

Individual measuring stations are identified in DIS by customer by station number and Columbia's plant records by station number. The investments were aggregated by rate schedule and reduced to percentages to produce Factor No. 17. See Exhibit KLJ-2 Page 28.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 18 - Other Distribution Expense

Factor No. 18 is based on the spread of dollars to the various classes of customers within the following distribution expense accounts:

Page 7 - Distribution Expense Allocation

Line 19 Account 871 - Distribution Load Dispatch

Line 20 Account 874 - Mains & Services

Line 21 Account 875 - M & R - General

Line 22 Account 876 - M & R - Industrial

Line 23 Account 878 - Meters & House Regulators

Line 24 Account 879 - Customer Installation

Line 29 Account 886 - Structures & Improvements

Line 30 Account 887 - Mains

Line 31 Account 889 - M & R - General

Line 32 Account 890 - M & R - Industrial

Line 33 Account 892 - Services

Line 34 Account 893 - Meters & House Regulators

See Exhibit KLJ-2, Page 29.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 19 – O&M Excl Gas Pur, Uncollectibles, & A&G

Factor No. 19 is based on total Operating and Maintenance Expenses (Page 8, Line 37) less Gas Purchased Cost (Page 7, Line 1), Uncollectibles (Page 8, Lines 5, 6, 7, 9, & 10), USP Rider (Page 8, Line 8) and A&G Expenses (Page 8, Line 36). See Exhibit KLJ-2, Page 30.

Factor No. 20 Minimum System Mains

Factor No. 20 is a composite using customers and design day quantities to allocate mains. The development of the factor is presented on Exhibit KLJ-2, Page 31.

A minimum 2" system approach is used to determine the customer related cost component of mains. The concept is based on the assumption that in order for a customer to obtain service, mains of at least the most common, minimum size in the distribution system must be present. That portion of the Mains Account investment is considered customer-related and is computed by multiplying the total pipe quantity in the system by the cost per foot for the most prevalent size of mains, that being two inch. The cost of the minimum system, computed in that manner, is divided by the total cost of all mains to arrive at a Customer Component factor. The reciprocal of the Customer Component factor becomes the Demand Component factor and is used to allocate the remaining mains costs which are considered demand related and allocated using the appropriate design day factor.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 21 – House Regulators

Factor No. 21 is based on the bill counts for all customers that are not served by low pressure lines. These counts are segregated by customer class and converted to percentages to create Factor No. 21 and used for assigning account 383 House Regulators as well as the investment in account 384 House Regulator Installations since these costs are incurred in direct relation with House Regulators. See Exhibit KLJ-2, Page 32.

Factor No. 22 – Average Factor Nos. 5 & 20

Factor No. 22 is based on the average of Factor Nos. 5 and 20 on an equal basis and is used to average the Customer-Demand Study and the Peak and Average Study. See Exhibit KLJ-2, Page 33.

Factor No. 23 – Meters and House Regulators

Factor No. 23 reflects the relationship based on the spread of dollars in accounts 381 Meters, 381.10 Automatic Meter Reading, 382 Meter Installations, 383 House Regulators, and 384 House Regulator Installations (Page 3, Lines 34 through 39) among all customer classes resulting from the application of the appropriate account allocation factor. The allocated dollars in each account are aggregated and reduced to percentages to produce Factor No. 23. See Exhibit KLJ-2, Page 34.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 24 - Labor

Factor No. 24 is based on the allocation of labor charges with the various Federal Energy Regulatory Committee ("FERC") Accounts. The labor dollars allocated to the various rate classes are summed and converted to percentages to create Factor No. 24. See Exhibit KLJ-2, Page 35.

Factor No. 25 – Sales and CHOICE Transportation

Factor No. 25 is based on the sales and CHOICE transportation activity for the twelve months ending December 31, 2026. See Exhibit KLJ-2, Page 2.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 1
DESIGN DAY [1] (2024-2025)

LINE NO.	Rate	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	FLEX	Total
	<u>Residential</u>							
1	RS	353,600	0	0	0	0	0	353,600
2	RC2	32,800	0	0	0	0	0	32,800
3	RTC	62,300	0	0	0	0	0	62,300
	<u>Commercial</u>							
4	LDS/LGSS	0	0	0	0	15,500	0	15,500
5	LDS FLEX	0	0	0	0	0	16,100	16,100
6	SDS/LGSS	0	0	0	45,400	0	0	45,400
7	SDS FLEX	0	0	0	0	0	100	100
8	SGS2	0	0	51,900	0	0	0	51,900
9	SGS1	0	60,600	0	0	0	0	60,600
10	SCD1	0	20,600	0	0	0	0	20,600
11	SCD2	0	0	24,600	0	0	0	24,600
12	SGDS1	0	2,700	0	0	0	0	2,700
13	SGDS2	0	0	32,000	0	0	0	32,000
	<u>Industrial</u>							
14	LDS/LGSS	0	0	0	0	36,300	0	36,300
15	LDS FLEX	0	0	0	0	0	26,600	26,600
16	SDS/LGSS	0	0	0	10,900	0	0	10,900
17	SGS2	0	0	500	0	0	0	500
18	SGS1	0	100	0	0	0	0	100
19	SGDS2	<u>0</u>	<u>0</u>	<u>1,000</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>1,000</u>
20	Total	448,700	84,000	110,000	56,300	51,800	42,800	793,600
21	MLDS							25,900
22	Other (Co. Used)							<u>2,000</u>
23	Total							821,500
24	ALLOCATOR #1	56.540%	10.585%	13.861%	7.094%	6.527%	5.393%	100.000%

[1] Includes Firm and Non-Firm Service. Volumes in MDth/Day.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS 2, 3, & 25
THROUGHPUT EXCLUDING TRANSPORTATION, THROUGHPUT EXCLUDING MLDS

LINE NO.		<u>RSS/RDS</u>	<u>SGS/DS-1</u>	<u>SGS/DS-2</u>	<u>SDS/LGSS</u>	<u>LDS/LGSS</u>	<u>MLDS</u>	<u>FLEX</u>	<u>TOTAL</u>
	<u>Sales</u>								
1	RSS	27,293,489.2	-	-	-	-	-	-	27,293,489.2
2	RDGSS	-	-	-	-	-	-	-	-
3	RC2 1/	2,495,400.8	-	-	-	-	-	-	2,495,400.8
4	SGSS1	-	3,983,415.9	-	-	-	-	-	3,983,415.9
5	SGSS2	-	-	3,825,270.3	-	-	-	-	3,825,270.3
6	NSS/MLSS-1	-	-	-	-	-	60,000.0	-	60,000.0
7	LGSS1 & 2	-	-	-	1,054,673.3	-	-	-	1,054,673.3
8	LGSS3 & greater	-	-	-	-	17,784.3	-	-	17,784.3
	<u>Transportation</u>								
9	RDS	3,683,080.7	-	-	-	-	-	-	3,683,080.7
10	RDGDS	-	-	-	-	-	-	-	-
11	SCD1	-	1,396,372.8	-	-	-	-	-	1,396,372.8
12	SCD2	-	-	1,864,575.7	-	-	-	-	1,864,575.7
13	SGDS1	-	240,725.2	-	-	-	-	-	240,725.2
14	SGDS2	-	-	3,350,063.1	-	-	-	-	3,350,063.1
15	SDS	-	-	-	6,651,766.2	-	-	-	6,651,766.2
16	LDS	-	-	-	-	10,530,612.1	-	-	10,530,612.1
17	FLEX	-	-	-	-	-	-	8,874,400.0	8,874,400.0
18	MLDS	-	-	-	-	-	5,891,000.0	-	5,891,000.0
19	Total Throughput Excl. Trans. (Allocator 2)	29,788,890.0	3,983,415.9	3,825,270.3	1,054,673.3	17,784.3	60,000.0	-	38,730,033.8
20	ALLOCATOR #2	76.914%	10.285%	9.877%	2.723%	0.046%	0.155%	0.000%	
21	Total Throughput Excl. MLDS (Allocator 3)	33,471,970.7	5,620,513.9	9,039,909.1	7,706,439.5	10,548,396.4	-	8,874,400.0	75,261,629.6
22	ALLOCATOR #3	44.474%	7.468%	12.011%	10.240%	14.016%	-	11.791%	
23	Sales and Choice Volume	33,471,970.7	5,379,788.7	5,689,846.0	1,054,673.3	17,784.3	60,000.0	-	45,674,063.0
24	ALLOCATOR #25	73.285%	11.779%	12.457%	2.309%	0.039%	0.131%	0.000%	

NOTE: 1/ RC2 rate schedule is for CAP customers. They can be either CHOICE or Sales.

**COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 4
GAS PURCHASE EXPENSE**

LINE NO.		<u>RSS/RDS</u> <u>GAS COST</u>	<u>SGS/DS-1</u> <u>GAS COST</u>	<u>SGS/DS-2</u> <u>GAS COST</u>	<u>SDS/LGSS</u> <u>GAS COST</u>	<u>LDS/LGSS</u> <u>GAS COST</u>	<u>MLDS</u> <u>GAS COST</u>	<u>FLEX</u> <u>GAS COST</u>	<u>TOTAL</u>
1	RSS	157,229,603	-	-	-	-	-	-	157,229,603
2	RC2	14,375,255	-	-	-	-	-	-	14,375,255
3	RDS	10,452,583	-	-	-	-	-	-	10,452,583
4	SGSS	-	22,947,264	22,036,235	-	-	-	-	44,983,499
5	NSS	-	-	-	-	204,869	-	-	204,869
6	SCD	-	3,962,906	5,291,666	-	-	-	-	9,254,572
7	SGDS	-	163,278	2,189,720	-	-	-	-	2,352,998
8	LGS	-	-	-	6,075,656	102,450	-	-	6,178,106
9	TOTAL	182,057,441	27,073,448	29,517,621	6,075,656	102,450	204,869	-	245,031,485
10	ALLOCATOR #4	74.299%	11.049%	12.046%	2.480%	0.042%	0.084%	0.000%	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2024

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

PAGE 1

WITNESS: K. L. Johnson

<u>Line</u> <u>No.</u>	<u>Description</u>	<u>Alloc</u>	<u>Total</u> <u>Company</u>	<u>RSS/RDS</u>	<u>SGS/DS-1</u>	<u>SGS/DS-2</u>	<u>SDS/LGSS</u>	<u>LDS/LGSS</u>	<u>FLEX</u>
1	Throughput Volumes (Total Company excl MLDS)		75,261,630	33,471,971	5,620,514	9,039,909	7,706,440	10,548,396	8,874,400
2	Percent Throughput		100.000%	44.474%	7.468%	12.011%	10.240%	14.016%	11.791%
3	Throughput Component		50.000%	22.236%	3.734%	6.006%	5.120%	7.008%	5.896%
4	Design Day Volumes (Total Company excl MLDS)		793,600	448,700	84,000	110,000	56,300	51,800	42,800
5	Percent Design Day Volumes		100.000%	56.540%	10.585%	13.861%	7.094%	6.527%	5.393%
6	Demand Component		50.000%	28.268%	5.293%	6.931%	3.547%	3.264%	2.697%
7	Demand/Commodity Factor		100.000%	50.504%	9.027%	12.937%	8.667%	10.272%	8.593%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 6
AVERAGE NO. OF CUSTOMERS

										[1] Total No of Bills (Incl Final) Final Bills	
LINE	NO.	TARIFF RATE SCHEDULES	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX		
	1	RSS	4,150,758	0	0	0	0	0	0	4,208,973	58,215
	2	RC2	261,703	0	0	0	0	0	0	265,520	3,817
	3	RDS	538,794	0	0	0	0	0	0	542,536	3,742
	4	RDGDS	0	0	0	0	0	0	0	0	0
	5	SGSS1	0	285,360	0	0	0	0	0	287,160	1,800
	6	SGSS2	0	0	30,633	0	0	0	0	30,737	104
	7	NSS	0	0	0	0	0	12	0	12	0
	8	SCD1	0	83,994	0	0	0	0	0	84,296	302
	9	SCD2	0	0	14,718	0	0	0	0	14,747	29
	10	SGDS1	0	10,458	0	0	0	0	0	10,474	16
	11	SGDS2	0	0	16,290	0	0	0	0	16,332	42
	12	LGSS1 & 2	0	0	0	911	0	0	0	913	2
	13	LGSS3 & greater	0	0	0	0	24	0	0	24	0
	14	SDS	0	0	0	4,452	0	0	0	4,461	9
	15	LDS	0	0	0	0	924	0	0	927	3
	16	FLEX	0	0	0	0	0	0	144	144	0
	17	MLDS	0	0	0	0	0	120	0	122	2
	18	Total Number of Bills	4,951,255	379,812	61,641	5,363	948	132	144	5,467,378	68,083
	19	Average Number of Customers	412,605	31,651	5,137	447	79	11	12		
	20	ALLOCATOR #6	91.702%	7.034%	1.142%	0.099%	0.018%	0.002%	0.003%		

[1] Used only in the Customer Charge calculation.

**COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 7
CURRENT DIS REVENUE**

<u>LINE NO.</u>	<u>ACCOUNT</u>	<u>TOTAL</u>	<u>RSS/RDS</u>	<u>SGS/DS-1</u>	<u>SGS/DS-2</u>	<u>SDS/LGSS</u>	<u>LDS/LGSS</u>	<u>MLDS</u>	<u>FLEX</u>
		<u>Total</u>	<u>Residential</u>	<u>Commercial</u>	<u>Industrial</u>				
1	DIS Billed Net Charge-offs - Sales Only	10,607,752.61	10,000,580.39	583,691.34	23,480.88				
2	DIS Billed Revenue - Comm/Ind Sales Only	113,473,043		64,496,227	48,976,816	0	0	0	0
3	Percent	100.000%		56.838%	43.162%	0.000%	0.000%	0.000%	0.000%
4	Allocated DIS Billed Sales Net Charge-offs	10,607,752.61	10,000,580.39	331,758.48	275,413.74	0.00	0.00	0.00	0.00
		<u>Total</u>	<u>Residential</u>	<u>Commercial</u>	<u>Industrial</u>				
5	DIS Billed Net Charge-offs - Choice Only	782,161.16	663,540.39	118,620.77	0.00				
6	DIS Billed Revenue - Comm/Ind Choice Only	64,836,768		20,418,475	44,418,293	0	0	0	0
7	Percent	100.000%		31.492%	68.508%	0.000%	0.000%	0.000%	0.000%
8	Allocated DIS Billed Choice Net Charge-offs	782,161.16	663,540.39	37,356.05	81,264.72	0.00	0.00	0.00	0.00
9	Total DIS Billed Net Charge-offs	11,389,913.77	10,664,120.78	369,114.53	356,678.46	0.00	0.00	0.00	0.00
10	ALLOCATOR #7	100.000%	93.627%	3.241%	3.132%	0.000%	0.000%	0.000%	0.000%

**COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 8
CURRENT GMB/GTS REVENUE**

LINE NO.	<u>ACCOUNT</u>	<u>TOTAL</u>	<u>RSS/RDS</u>	<u>SGS/DS-1</u>	<u>SGS/DS-2</u>	<u>SDS/LGSS</u>	<u>LDS/LGSS</u>	<u>MLDS</u>	<u>FLEX</u>
1	CURRENT GMB/GTS REVENUE	78,773,555	-	105,158	1,738,383	42,005,352	29,719,961	2,090,710	3,113,991
2	ALLOCATOR #8	100.000%	0.000%	0.134%	2.207%	53.324%	37.728%	2.654%	3.953%

**COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 9
DIRECT ASSIGNMENT - CUSTOMER DEPOSITS**

LINE NO.		<u>RSS/RDS</u>	<u>SGS/DS-1</u>	<u>SGS/DS-2</u>	<u>SDS/LGSS</u>	<u>LDS/LGSS</u>	<u>TOTAL</u>
1	Residential Unlisted	38,314	-	-	-	-	38,314
2	RS	2,213,238	-	-	-	-	2,213,238
3	RTC	202,703	-	-	-	-	202,703
4	Commercial Unlisted	-	52,682	-	-	-	52,682
5	SCC	-	56,062	-	-	-	56,062
6	LG1	-	-	-	-	-	-
7	SC2	-	-	52,674	-	-	52,674
8	SGS	-	1,038,969	-	-	-	1,038,969
9	SGT	-	15,612	-	-	-	15,612
10	SG2	-	-	217,314	-	-	217,314
11	Industrial Unlisted	-	-	-	-	-	-
12	SG3	-	5,284	-	-	-	5,284
13	TOTAL	2,454,255	1,168,609	269,988	-	-	3,892,852
14	ALLOCATOR #9	63.04600%	30.019%	6.935%	0.000%	0.000%	100.000%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 10
FORFEITED DISCOUNTS

LINE ACCT.

<u>NO.</u>	<u>NO.</u>	<u>ACCOUNT</u>	<u>TOTAL</u>	<u>RSS/RDS</u>	<u>SGS/DS-1</u>	<u>SGS/DS-2</u>	<u>SDS/LGSS</u>	<u>LDS/LGSS</u>	<u>MLDS</u>	<u>FLEX</u>
1	487.00	FORFEITED DISCOUNTS - DIS	1,733,367	1,349,976	175,604	193,141	14,646	-	-	-
2	487.00	FORFEITED DISCOUNTS - GMB & GTS	<u>162,904</u>	<u>-</u>	<u>217</u>	<u>3,595</u>	<u>86,867</u>	<u>61,461</u>	<u>4,324</u>	<u>6,440</u>
3		TOTAL CURRENT SALES AND TRANSPORTATION REVENUE	1,896,271	1,349,976	175,821	196,736	101,513	61,461	4,324	6,440
4		ALLOCATOR #10	100.000%	71.191%	9.272%	10.375%	5.353%	3.241%	0.228%	0.340%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 11
DISTRIBUTION PLANT EXCLUDING ACCOUNTS 375.70, 375.71, & 387

LINE	ACCT.									
NO.	NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	374.10	LAND - CITY GATE & M/L IND M&R	21,944	11,083	1,981	2,839	1,902	2,254	-	1,886
2	374.20	LAND - OTHER DISTRIBUTION	3,361,033	1,697,456	303,400	434,817	291,301	345,245	-	288,814
3	374.30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	48,161	8,608	12,337	8,265	9,796	-	8,194
4	374.40	LAND RIGHTS - OTHER DISTRIBUTION	11,269,188	5,691,390	1,017,270	1,457,895	976,701	1,157,571	-	968,361
5	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	-	-	-	-	-	-	-	-
6	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	13	7	1	2	1	1	-	1
7	374.50	RIGHTS OF WAY	3,233,314	1,632,953	291,871	418,294	280,231	332,126	-	277,839
8	374.50	DIRECT - RIGHTS OF WAY	-	-	-	-	-	-	-	-
9	375.20	M & R STRUCTURES - CITY GATE	7,026	3,549	634	909	609	722	-	604
10	375.31	M & R STRUCTURES - LOCAL GAS PURCH	4,012	2,026	362	519	348	412	-	345
11	375.40	M & R STRUCTURES - REGULATING	8,776,354	4,432,410	792,242	1,135,397	760,647	901,507	-	754,152
12	375.40	DIRECT - M & R STRUCTURES - REGULATING	27,126	-	-	-	-	-	27,126	-
13	375.60	M & R STRUCTURES - DIST. IND. M & R	85,565	-	1,158	14,873	30,322	28,401	-	10,812
14	375.80	M & R STRUCTURES - COMMUNICATION	16,515	8,341	1,491	2,137	1,431	1,696	-	1,419
15	376.00	MAINS	3,505,714,084	1,770,525,841	316,460,810	453,534,231	303,840,240	360,106,951	-	301,246,011
16	376.00	DIRECT - MAINS - MLDS	134,476	-	-	-	-	-	134,476	-
17	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,876,258	2,122,743	3,042,198	2,038,087	2,415,510	-	2,020,685
18	376.30	MAINS-BARE STEEL	27,518,961	13,898,176	2,484,137	3,560,128	2,385,068	2,826,748	-	2,364,704
19	376.30	DIRECT - MAINS-BARE STEEL	79,601	-	-	-	-	-	79,601	-
20	376.80	MAINS-CAST IRON	148,699	75,099	13,423	19,237	12,888	15,274	-	12,778
21	378.10	M & R EQUIP - GENERAL	1,442,416	728,478	130,207	186,605	125,014	148,165	-	123,947
22	378.20	M & R EQUIP - GENERAL - REGULATING	195,425,261	98,697,574	17,641,038	25,282,166	16,937,507	20,074,083	-	16,792,893
23	378.20	DIRECT - M & R EQUIP-GEN-REG	678,970	-	-	-	-	-	-	678,970
24	378.30	M & R EQUIP - LOCAL GAS PURCHASES	405,818	204,954	36,633	52,501	35,172	41,686	-	34,872
25	379.10	M & R EQUIP - CITY GATE	120,061	60,636	10,838	15,532	10,406	12,333	-	10,317
26	379.11	M & R EQUIP - EXCHANGE GAS	(903)	(456)	(82)	(117)	(78)	(93)	-	(78)
27	380.00	SERVICES	1,012,851,914	924,754,055	72,165,699	12,974,633	2,096,604	577,326	-	283,599
28	380.00	DIRECT - SERVICES	1,554	-	-	-	-	-	1,554	-
29	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-	-
30	381.00	METERS	59,647,664	46,670,718	8,635,789	3,866,958	365,044	89,472	8,947	10,737
31	381.00	DIRECT - METERS - MLDS FLEX	16,319	-	-	-	-	-	-	16,319
32	381.10	AUTOMATIC METER READING	29,057,053	22,735,400	4,206,880	1,883,769	177,829	43,586	4,359	5,230
33	382.00	METER INSTALLATIONS	58,083,634	45,446,959	8,409,349	3,765,562	355,472	87,126	8,713	10,455
34	383.00	HOUSE REGULATORS	22,247,918	20,373,086	1,535,774	301,459	30,925	5,117	667	890
35	384.00	HOUSE REG INSTALLATIONS	3,546,998	3,248,093	244,849	48,062	4,930	816	106	142
36	385.00	IND M&R EQUIPMENT	9,291,861	-	125,719	1,615,111	3,292,757	3,084,155	-	1,174,120
37	385.00	DIRECT - IND M&R EQUIPMENT	474,267	-	-	-	-	-	474,267	-
38	385.10	IND M&R EQUIPMENT - LG VOLUME	984,132	-	13,315	171,062	348,747	326,653	-	124,355
39		TOTAL	4,978,283,690	2,972,822,246	436,656,139	513,799,115	334,408,367	392,634,636	739,817	327,223,371
40		ALLOCATOR #11	100.000%	59.716%	8.771%	10.321%	6.717%	7.887%	0.015%	6.573%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

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LINE	ACCT.		GROSS							
<u>NO.</u>	<u>NO.</u>	<u>ACCOUNT</u>	<u>PLANT</u>	<u>RSS/RDS</u>	<u>SGS/DS-1</u>	<u>SGS/DS-2</u>	<u>SDS/LGSS</u>	<u>LDS/LGSS</u>	<u>MLDS</u>	<u>FLEX</u>
1	301.00	Organizational Costs	100,099							
2	302.21	Franchises/Consent, Perpetual	26,216							
3	303.00	Misc Intangible Plant	4,809,062							
4	303.30	Misc Software	93,418,877							
5	305.00	Structures & Improvements	0							
6	301-303	TOTAL INTANGIBLE PLANT	98,354,255	58,733,227	8,626,652	10,151,143	6,606,455	7,757,200	14,753	6,464,825
7	350.10	Land	23,882							
8	350.20	Rights of Way	1,932							
9	351.20	Compressor Station Structures	3,294,840							
10	352.01	Wells Construction	1,126,772							
11	352.02	Wells Equipment	1,072,322							
12	352.10	Storage Leasehold and Rights	139,442							
13	352.12	Other Leases	67,498							
14	353.00	Lines	385,797							
15	354.00	Compressor Station Equipment	1,911,603							
16	355.00	Measuring & Regulating Equipment	104,477							
17	362.00	Gas Holders	0							
18	362.10	Environmental Remediation	0							
19	350-362	TOTAL UNDERGROUND STORAGE	8,128,565	5,957,019	957,464	1,012,575	187,689	3,170	10,648	0
20	374.10	LAND - CITY GATE & M/L IND M&R	21,944	11,083	1,981	2,839	1,902	2,254	0	1,886
21	374.20	LAND - OTHER DISTRIBUTION	3,361,033	1,697,456	303,400	434,817	291,301	345,245	0	288,814
22	374.30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	48,161	8,608	12,337	8,265	9,796	0	8,194
23	374.40	LAND RIGHTS - OTHER DISTRIBUTION	11,269,188	5,691,390	1,017,270	1,457,895	976,701	1,157,571	0	968,361
24	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	0	0	0	0	0	0	0	0
25	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	13	7	1	2	1	1	0	1
26	374.50	RIGHTS OF WAY	3,233,314	1,632,953	291,871	418,294	280,231	332,126	0	277,839
27	374.50	DIRECT - RIGHTS OF WAY	0	0	0	0	0	0	0	0
28	375.20	M & R STRUCTURES - CITY GATE	7,026	3,549	634	909	609	722	0	604
29	375.31	M & R STRUCTURES - LOCAL GAS PURCH	4,012	2,026	362	519	348	412	0	345
30	375.40	M & R STRUCTURES - REGULATING	8,776,354	4,432,410	792,242	1,135,397	760,647	901,507	0	754,152
31	375.40	DIRECT - M & R STRUCTURES - REGULATING	27,126	0	0	0	0	0	27,126	0
32	375.60	M & R STRUCTURES - DIST. IND. M & R	85,565	0	1,158	14,873	30,322	28,401	0	10,812
33	375.70	M & R STRUCTURES - OTHER	52,038,716	31,075,440	4,564,316	5,370,916	3,495,441	4,104,294	7,806	3,420,505
34	375.71	M & R STRUCTURES - OTHER LEASED	6,276,007	3,747,780	550,469	647,747	421,559	494,989	941	412,522
35	375.80	M & R STRUCTURES - COMMUNICATION	16,515	8,341	1,491	2,137	1,431	1,696	0	1,419
36	376.00	MAINS	3,505,714,084	1,770,525,841	316,460,810	453,534,231	303,840,240	360,106,951	0	301,246,011
37	376.00	DIRECT - MAINS - MLDS	134,476	0	0	0	0	0	134,476	0
38	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,876,258	2,122,743	3,042,198	2,038,087	2,415,510	0	2,020,685

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

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LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
<u>DISTRIBUTION PLANT</u>										
1	376.30	MAINS-BARE STEEL	27,518,961	13,898,176	2,484,137	3,560,128	2,385,068	2,826,748	0	2,364,704
2	376.30	DIRECT - MAINS-BARE STEEL	79,601	0	0	0	0	0	79,601	0
3	376.80	MAINS-CAST IRON	148,699	75,099	13,423	19,237	12,888	15,274	0	12,778
4	378.10	M & R EQUIP - GENERAL	1,442,416	728,478	130,207	186,605	125,014	148,165	0	123,947
5	378.20	M & R EQUIP - GENERAL - REGULATING	195,425,261	98,697,574	17,641,038	25,282,166	16,937,507	20,074,083	0	16,792,893
6	378.20	DIRECT - M & R EQUIP-GEN-REG	678,970	0	0	0	0	0	0	678,970
7	378.30	M & R EQUIP - LOCAL GAS PURCHASES	405,818	204,954	36,633	52,501	35,172	41,686	0	34,872
8	379.10	M & R EQUIP - CITY GATE	120,061	60,636	10,838	15,532	10,406	12,333	0	10,317
9	379.11	M & R EQUIP - EXCHANGE GAS	(903)	(456)	(82)	(117)	(78)	(93)	0	(78)
10	380.00	SERVICES	1,012,851,914	924,754,055	72,165,699	12,974,633	2,096,604	577,326	0	283,599
11	380.00	DIRECT - SERVICES	1,554	0	0	0	0	0	1,554	0
12	380.12	CSL REPLACEMENT	0	0	0	0	0	0	0	0
13	381.00	METERS	59,647,664	46,670,718	8,635,789	3,866,958	365,044	89,472	8,947	10,737
14	381.00	DIRECT - METERS - MLDS FLEX	16,319	0	0	0	0	0	0	16,319
15	381.10	AUTOMATIC METER READING	29,057,053	22,735,400	4,206,880	1,883,769	177,829	43,586	4,359	5,230
16	382.00	METER INSTALLATIONS	58,083,634	45,446,959	8,409,349	3,765,562	355,472	87,126	8,713	10,455
17	383.00	HOUSE REGULATORS	22,247,918	20,373,086	1,535,774	301,459	30,925	5,117	667	890
18	384.00	HOUSE REG INSTALLATIONS	3,546,998	3,248,093	244,849	48,062	4,930	816	106	142
19	385.00	IND M&R EQUIPMENT	9,291,861	0	125,719	1,615,111	3,292,757	3,084,155	0	1,174,120
20	385.00	DIRECT - IND M&R EQUIPMENT	474,267	0	0	0	0	0	474,267	0
21	385.10	IND M&R EQUIPMENT - LG VOLUME	984,132	0	13,315	171,062	348,747	326,653	0	124,355
22	387.10	OTHER EQUIP DISTRIBUTION	19,450	11,615	1,706	2,008	1,307	1,534	3	1,279
23	387.20	OTHER EQUIP ODORIZATION	117,248	70,016	10,284	12,101	7,876	9,247	18	7,707
24	387.42	OTHER EQUIP RADIO	119,609	71,426	10,491	12,345	8,034	9,434	18	7,862
25	387.44	OTHER EQUIP COMMUNICATION	554,949	331,394	48,675	57,276	37,276	43,769	83	36,477
26	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	18,068,379	10,789,713	1,584,778	1,864,837	1,213,653	1,425,053	2,710	1,187,635
27	387.45	DIRECT - OTHER EQUIP CUSTOMER INFO SER'	69,585	0	0	0	0	0	69,585	0
28	387.50	GPS EQUIPMENT	<u>2,201,372</u>	<u>1,314,571</u>	<u>193,082</u>	<u>227,204</u>	<u>147,866</u>	<u>173,622</u>	<u>330</u>	<u>144,696</u>
29	374-387	TOTAL DISTRIBUTION	5,057,749,006	3,020,234,200	443,619,938	521,993,548	339,741,378	398,896,577	821,311	332,442,053

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

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LINE	ACCT.		GROSS							
<u>NO.</u>	<u>NO.</u>	<u>ACCOUNT</u>	<u>PLANT</u>	<u>RSS/RDS</u>	<u>SGS/DS-1</u>	<u>SGS/DS-2</u>	<u>SDS/LGSS</u>	<u>LDS/LGSS</u>	<u>MLDS</u>	<u>FLEX</u>
		<u>GENERAL PLANT</u>								
1	389.20	Land Rights	0							
2	390.10	Str, Communications	49,821							
3	391.10	OF&E Unspecified	7,142,560							
4	391.11	OF&E Data Handling Equipment	66,877							
5	391.12	OF&E Information Systems	129,970							
6	391.20	OF&E Air Cond Equip	0							
7	392.20	Trans Eq Trailers > \$1,000	14,787							
8	392.21	Trans Eq Trailers \$1,000 or >	10,830							
9	393.00	Stores Equipment	0							
10	394.10	Tools, Garage & Service Eq	387,740							
11	394.11	CNG Equip - Stationary	18,450							
12	394.12	CNG Equip - Portable	0							
13	394.20	Shop Equipment	0							
14	394.30	Tools & Other	39,030,728							
15	394.31	High Pressure Stopping	10,847							
16	395.00	Laboratory Equipment, Gas	264,921							
17	396.00	Power Operated Equipment	948,698							
18	397.00	Communication Equipment	0							
19	397.10	Communication Equipment-Telephone	0							
20	397.20	Communication Equipment-Radio	0							
21	397.40	Communication Equipment-Other	0							
22	397.50	Communication Equipment-Telemetry	6,391,394							
23	398.00	Miscellaneous Equipment	1,180,276							
24	389-398	TOTAL GENERAL PLANT	55,647,899	33,230,699	4,880,877	5,743,420	3,737,869	4,388,950	8,347	3,657,736
25		TOTAL	5,219,879,725	3,118,155,145	458,084,931	538,900,686	350,273,392	411,045,897	855,060	342,564,614
		ALLOCATOR #12		59.736%	8.776%	10.324%	6.710%	7.875%	0.016%	6.563%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 13
DIRECT PLANT - MAINS

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	376.00	MAINS	3,505,714,084	1,770,525,841	316,460,810	453,534,231	303,840,240	360,106,951	-	301,246,011
2	376.00	DIRECT - MAINS - MLDS	134,476	-	-	-	-	-	134,476	-
3	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,876,258	2,122,743	3,042,198	2,038,087	2,415,510	-	2,020,685
4	376.30	MAINS-BARE STEEL	27,518,961	13,898,176	2,484,137	3,560,128	2,385,068	2,826,748	-	2,364,704
5	376.30	DIRECT - MAINS-BARE STEE	79,601	-	-	-	-	-	79,601	-
6	376.80	MAINS-CAST IRON	148,699	75,099	13,423	19,237	12,888	15,274	-	12,778
7		TOTAL	3,557,111,303	1,796,375,374	321,081,113	460,155,794	308,276,283	365,364,483	214,078	305,644,179
		ALLOCATOR #13	100.000%	50.503%	9.026%	12.936%	8.666%	10.271%	0.006%	8.592%

**COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 14
COMPOSITE DIRECT PLANT - ACCOUNTS 376 & 380**

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	376.00	MAINS	3,505,714,084	1,770,525,841	316,460,810	453,534,231	303,840,240	360,106,951	-	301,246,011
2	376.00	DIRECT - MAINS - MLDS	134,476	-	-	-	-	-	134,476	-
3	376.08	MAINS-CSL REPLACEMENTS	23,515,481	11,876,258	2,122,743	3,042,198	2,038,087	2,415,510	-	2,020,685
4	376.30	MAINS-BARE STEEL	27,518,961	13,898,176	2,484,137	3,560,128	2,385,068	2,826,748	-	2,364,704
5	376.30	DIRECT - MAINS-BARE STEEL	79,601	-	-	-	-	-	79,601	-
6	376.80	MAINS-CAST IRON	148,699	75,099	13,423	19,237	12,888	15,274	-	12,778
7	380.00	SERVICES	1,012,851,914	924,754,055	72,165,699	12,974,633	2,096,604	577,326	-	283,599
8	380.00	DIRECT - SERVICES	1,554	-	-	-	-	-	1,554	-
9	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-	-
10		TOTAL	4,569,964,771	2,721,129,429	393,246,811	473,130,427	310,372,886	365,941,809	215,632	305,927,777
11		ALLOCATOR #14	100.000%	59.543%	8.605%	10.353%	6.792%	8.008%	0.005%	6.694%

Columbia Gas of Pennsylvania, Inc.
Services Allocation Factor
As of November 30, 2024

Line No.	Billing Rate	Rate Case Rate	Classification	BLANK	P	S	*	±	Total	Average Unit Cost	Total Cost	Key
1	808	FLEX	4"	0	0	0	1	0	1	6,140.85	6,140.85	8084"
2	809	FLEX	6"	1	0	0	0	0	1	6,450.46	6,450.46	8096"
3	809	FLEX	8"	0	0	0	1	0	1	7,612.29	7,612.29	8098"
4	810	FLEX	4"	1	0	0	0	0	1	6,140.85	6,140.85	8104"
5	810	FLEX	6"	1	0	0	0	0	1	6,450.46	6,450.46	8106"
6	833	FLEX	8"	0	0	0	0	1	1	7,612.29	7,612.29	8338"
7	846	FLEX	UNDER 3"	0	0	0	1	0	1	1,916.58	1,916.58	846UNDER 3"
8	846	FLEX	6"	0	0	0	0	1	1	6,450.46	6,450.46	8466"
9	875	FLEX	6"	2	0	0	0	0	2	6,450.46	12,900.92	8756"
10	875	FLEX	8"	0	0	0	1	0	1	7,612.29	7,612.29	8758"
11	879	FLEX	UNDER 3"	1	0	0	0	0	1	1,916.58	1,916.58	879UNDER 3"
12	880	FLEX	12"	1	0	0	0	0	1	160,483.09	160,483.09	88012"
13	881	FLEX	4"	1	0	0	0	0	1	6,140.85	6,140.85	8814"
14	881	FLEX	UNDER 3"	1	0	0	0	0	1	1,916.58	1,916.58	881UNDER 3"
15	882	FLEX	UNDER 3"	0	0	0	1	0	1	1,916.58	1,916.58	882UNDER 3"
16	LG1	SDS/LGSS	3"	1	0	0	1	0	2	2,487.18	4,974.36	LG13"
17	LG1	SDS/LGSS	4"	10	0	0	2	1	13	6,140.85	79,831.05	LG14"
18	LG1	SDS/LGSS	6"	0	0	0	1	0	1	6,450.46	6,450.46	LG16"
19	LG1	SDS/LGSS	UNDER 3"	21	0	1	5	0	27	1,916.58	51,747.66	LG1UNDER 3"
20	LG2	SDS/LGSS	3"	3	0	0	1	0	4	2,487.18	9,948.72	LG23"
21	LG2	SDS/LGSS	4"	8	0	0	2	1	11	6,140.85	67,549.35	LG24"
22	LG2	SDS/LGSS	6"	2	0	0	0	0	2	6,450.46	12,900.92	LG26"
23	LG2	SDS/LGSS	UNDER 3"	30	0	0	1	0	31	1,916.58	59,413.98	LG2UNDER 3"
24	LG3	LDS/LGSS	UNDER 3"	1	0	0	0	0	1	1,916.58	1,916.58	LG3UNDER 3"
25	LG4	LDS/LGSS	6"	1	0	0	0	0	1	6,450.46	6,450.46	LG46"
26	NSI	MDS/NSS	3"	1	0	0	0	0	1	2,487.18	2,487.18	NSI3"
27	RC2	RSS/RTS	UNDER 3"	14,590	102	64	2,020	2,312	19,088	1,916.58	36,583,679.04	RC2UNDER 3"
28	RC2	RSS/RTS	4"	1	0	0	0	0	1	6,140.85	6,140.85	RC24"
29	RC2	RSS/RTS	10"	0	0	0	0	1	1	111.64	111.64	RC210"
30	RS	RSS/RTS	10"	4	0	0	0	1	5	111.64	558.20	RS10"
31	RS	RSS/RTS	11-1/8"	1	0	0	0	0	1	0.00	0.00	RS11-1/8"
32	RS	RSS/RTS	3"	13	0	0	4	39	56	2,487.18	139,282.08	RS3"
33	RS	RSS/RTS	4"	14	1	1	4	59	79	6,140.85	485,127.15	RS4"
34	RS	RSS/RTS	5"	3	0	0	0	0	3	138.55	415.65	RS5"
35	RS	RSS/RTS	6"	7	0	0	2	3	12	6,450.46	77,405.52	RS6"
36	RS	RSS/RTS	8"	4	0	0	0	0	4	7,612.29	30,449.17	RS8"
37	RS	RSS/RTS	UNDER 3"	281,497	1,604	1,270	21,739	32,704	338,814	1,916.58	649,364,136.12	RSUNDER 3"
38	RTC	RSS/RTS	3"	1	0	0	0	5	6	2,487.18	14,923.08	RTC3"
39	RTC	RSS/RTS	4"	2	0	0	0	6	8	6,140.85	49,126.80	RTC4"
40	RTC	RSS/RTS	UNDER 3"	43,419	201	168	2,326	2,762	48,876	1,916.58	93,674,764.08	RTCUNDER 3"
41	SC2	SGSS2/SCD2/SGDS2	3"	27	1	0	1	1	30	2,487.18	74,615.40	SC23"
42	SC2	SGSS2/SCD2/SGDS2	4"	35	0	0	1	1	37	6,140.85	227,211.45	SC24"
43	SC2	SGSS2/SCD2/SGDS2	6"	2	0	0	0	0	2	6,450.46	12,900.92	SC26"
44	SC2	SGSS2/SCD2/SGDS2	UNDER 3"	897	7	8	123	94	1,129	1,916.58	2,163,818.82	SC2UNDER 3"
45	SCC	SGSS1/SCD1/SGDS1	3"	15	0	0	6	15	36	2,487.18	89,538.48	SCC3"
46	SCC	SGSS1/SCD1/SGDS1	4"	16	0	0	2	6	24	6,140.85	147,380.40	SCC4"
47	SCC	SGSS1/SCD1/SGDS1	UNDER 3"	4,282	43	27	1,189	1,404	6,945	1,916.58	13,310,648.10	SCCUNDER 3"
48	SG2	SGSS2/SCD2/SGDS2	10"	1	0	0	0	0	1	111.64	111.64	SG210"

Columbia Gas of Pennsylvania, Inc.												
Services Allocation Factor												
As of November 30, 2024												
49	SG2	SGSS2/SCD2/SGDS2	12"	1	0	0	0	0	1	0.00	0.00	SG212"
50	SG2	SGSS2/SCD2/SGDS2	3"	41	0	0	13	6	60	2,487.18	149,230.80	SG23"
51	SG2	SGSS2/SCD2/SGDS2	4"	46	2	0	12	13	73	6,140.85	448,282.05	SG24"
52	SG2	SGSS2/SCD2/SGDS2	6"	6	0	0	5	2	13	6,450.46	83,855.98	SG26"
53	SG2	SGSS2/SCD2/SGDS2	8"	1	0	0	0	0	1	7,612.29	7,612.29	SG28"
54	SG2	SGSS2/SCD2/SGDS2	UNDER 3"	1,875	9	8	248	222	2,362	1,916.58	4,526,961.96	SG2UNDER 3"
55	SG3	SGSS1/SCD1/SGDS1	3"	4	0	0	2	0	6	2,487.18	14,923.08	SG33"
56	SG3	SGSS1/SCD1/SGDS1	4"	2	0	0	2	0	4	6,140.85	24,563.40	SG34"
57	SG3	SGSS1/SCD1/SGDS1	6"	1	0	0	1	0	2	6,450.46	12,900.92	SG36"
58	SG3	SGSS1/SCD1/SGDS1	UNDER 3"	20	1	0	2	0	23	1,916.58	44,081.34	SG3UNDER 3"
59	SG4	SGSS2/SCD2/SGDS2	3"	2	0	0	1	0	3	2,487.18	7,461.54	SG43"
60	SG4	SGSS2/SCD2/SGDS2	4"	3	0	0	1	0	4	6,140.85	24,563.40	SG44"
61	SG4	SGSS2/SCD2/SGDS2	6"	1	0	0	0	0	1	6,450.46	6,450.46	SG46"
62	SG4	SGSS2/SCD2/SGDS2	UNDER 3"	24	0	0	5	1	30	1,916.58	57,497.40	SG4UNDER 3"
63	SG4	SGSS2/SCD2/SGDS2	10"	1	0	0	0	0	1	111.64	111.64	SG410"
64	SGS	SGSS1/SCD1/SGDS1	16"	0	0	0	1	0	1	0.00	0.00	SGS16"
65	SGS	SGSS1/SCD1/SGDS1	3"	26	0	0	15	60	101	2,487.18	251,205.18	SGS3"
66	SGS	SGSS1/SCD1/SGDS1	4"	34	0	0	13	33	80	6,140.85	491,268.00	SGS4"
67	SGS	SGSS1/SCD1/SGDS1	5"	1	0	0	1	1	3	138.55	415.65	SGS5"
68	SGS	SGSS1/SCD1/SGDS1	6"	1	0	0	0	1	2	6,450.46	12,900.92	SGS6"
69	SGS	SGSS1/SCD1/SGDS1	UNDER 3"	12,947	114	73	4,378	5,847	23,359	1,916.58	44,769,392.22	SGSUNDER 3"
70	SGT	INACTIVE	3"	1	0	0	0	0	1	2,487.18	2,487.18	SGT3"
71	SGT	INACTIVE	4"	4	0	0	1	1	6	6,140.85	36,845.10	SGT4"
72	SGT	INACTIVE	6"	0	0	0	0	1	1	6,450.46	6,450.46	SGT6"
73	SGT	INACTIVE	UNDER 3"	17	0	0	3	0	20	1,916.58	38,331.60	SGTUNDER 3"
74	TAG1	SGSS1/SCD1/SGDS1	3"	3	0	0	0	1	4	2,487.18	9,948.72	TAG13"
75	TAG1	SGSS1/SCD1/SGDS1	UNDER 3"	126	0	0	34	19	179	1,916.58	343,067.82	TAG1UNDER 3"
76	TAG2	SGSS2/SCD2/SGDS2	3"	11	0	0	1	0	12	2,487.18	29,846.16	TAG23"
77	TAG2	SGSS2/SCD2/SGDS2	4"	18	0	0	2	1	21	6,140.85	128,957.85	TAG24"
78	TAG2	SGSS2/SCD2/SGDS2	6"	3	0	0	0	0	3	6,450.46	19,351.38	TAG26"
79	TAG2	SGSS2/SCD2/SGDS2	UNDER 3"	253	1	0	22	5	281	1,916.58	538,558.98	TAG2UNDER 3"
80	TAG5	SGSS1/SCD1/SGDS1	3"	3	0	0	1	5	9	2,487.18	22,384.62	TAG53"
81	TAG5	SGSS1/SCD1/SGDS1	4"	8	0	0	1	2	11	6,140.85	67,549.35	TAG54"
82	TAG5	SGSS1/SCD1/SGDS1	UNDER 3"	481	3	2	58	131	675	1,916.58	1,293,691.50	TAG5UNDER 3"
83	TAG6	SGSS2/SCD2/SGDS2	3"	44	0	0	2	0	46	2,487.18	114,410.28	TAG63"
84	TAG6	SGSS2/SCD2/SGDS2	4"	56	0	1	8	5	70	6,140.85	429,859.50	TAG64"
85	TAG6	SGSS2/SCD2/SGDS2	6"	5	0	0	1	0	6	6,450.46	38,702.76	TAG66"
86	TAG6	SGSS2/SCD2/SGDS2	UNDER 3"	845	7	4	74	40	970	1,916.58	1,859,082.60	TAG6UNDER 3"
87	TI4	SDS/LGSS	12"	1	0	0	0	0	1	160,483.09	160,483.09	TI412"
88	TI4	SDS/LGSS	3"	13	0	0	2	0	15	2,487.18	37,307.70	TI43"
89	TI4	SDS/LGSS	4"	27	0	0	2	0	29	6,140.85	178,084.65	TI44"
90	TI4	SDS/LGSS	6"	3	0	0	1	1	5	6,450.46	32,252.30	TI46"
91	TI4	SDS/LGSS	UNDER 3"	116	1	0	12	5	134	1,916.58	256,821.72	TI4UNDER 3"
92	TI8	LDS/LGSS	3"	7	0	0	0	0	7	2,487.18	17,410.26	TI83"
93	TI8	LDS/LGSS	4"	15	0	0	1	1	17	6,140.85	104,394.45	TI84"
94	TI8	LDS/LGSS	6"	3	0	0	0	0	3	6,450.46	19,351.38	TI86"
95	TI8	LDS/LGSS	8"	0	1	1	0	0	2	7,612.29	15,224.58	TI88"
96	TI8	LDS/LGSS	UNDER 3"	19	0	0	3	2	24	1,916.58	45,997.92	TI8UNDER 3"
97	TIB	SDS/LGSS	3"	20	0	0	3	1	24	2,487.18	59,692.32	TIB3"
98	TIB	SDS/LGSS	4"	63	1	0	9	1	74	6,140.85	454,422.90	TIB4"
99	TIB	SDS/LGSS	6"	3	0	0	2	1	6	6,450.46	38,702.76	TIB6"
100	TIB	SDS/LGSS	8"	1	0	0	0	0	1	7,612.29	7,612.29	TIB8"
101	TIB	SDS/LGSS	UNDER 3"	114	1	0	13	3	131	1,916.58	251,071.98	TIBUNDER 3"

Columbia Gas of Pennsylvania, Inc. Services Allocation Factor As of November 30, 2024												
102	TIF	LDS/LGSS	3"	6	0	0	0	0	6	2,487.18	14,923.08	TIF3"
103	TIF	LDS/LGSS	4"	12	0	0	1	1	14	6,140.85	85,971.90	TIF4"
104	TIF	LDS/LGSS	6"	6	0	0	0	0	6	6,450.46	38,702.76	TIF6"
105	TIF	LDS/LGSS	8"	1	0	0	0	0	1	7,612.29	7,612.29	TIF8"
106	TIF	LDS/LGSS	UNDER 3"	48	1	1	2	1	53	1,916.58	101,578.74	TIFUNDER 3"
107	TIG	LDS/LGSS	3"	1	0	0	0	0	1	2,487.18	2,487.18	TIG3"
108	TIG	LDS/LGSS	4"	1	0	0	0	0	1	6,140.85	6,140.85	TIG4"
109	TIG	LDS/LGSS	8"	0	0	0	1	0	1	7,612.29	7,612.29	TIG8"
110	TIG	LDS/LGSS	UNDER 3"	2	0	0	0	0	2	1,916.58	3,833.16	TIGUNDER 3"
111	TIH	LDS/LGSS	6"	0	0	0	1	0	1	6,450.46	6,450.46	TIH6"
112	TM1	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,916.58	1,916.58	TM1UNDER 3"
113	TM3	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,916.58	1,916.58	TM3UNDER 3"
114	TM4	MDS/NSS	6"	1	0	0	0	0	1	6,450.46	6,450.46	TM46"
115	TM5	MDS/NSS	UNDER 3"	1	0	0	0	0	1	1,916.58	1,916.58	TM5UNDER 3"
116	TMB	MDS/NSS	4"	1	0	0	0	0	1	6,140.85	6,140.85	TMB4"
117	TMB	MDS/NSS	6"	3	0	0	1	0	4	6,450.46	25,801.84	TMB6"
118	TMB	MDS/NSS	8"	1	0	0	1	1	3	7,612.29	22,836.88	TMB8"
119	UNKNOWN			<u>2,511</u>	<u>16</u>	<u>14</u>	<u>491</u>	<u>1,022</u>	<u>4,054</u>	UNKNOWN	<u>UNKNOWN</u>	UNKNOWN
120				364,835	2,117	1,643	32,889	46,854	448,338		854,932,003.31	
121	Check Total			0	0	0	0	0	0	0		

		Total Cost	Percent
122	RSS/RTS	780,426,119.38	91.302%
123	SGSS1/SCD1/SGDS1	60,905,859.70	7.125%
124	SGSS2/SCD2/SGDS2	10,949,455.26	1.281%
125	SDS/LGSS	1,769,268.21	0.207%
126	LDS/LGSS	486,058.34	0.057%
127	FLEX	<u>241,661.13</u>	<u>0.028%</u>
128	TOTAL BEFORE MDS/NSS	854,778,422.02	100.000%
129	INACTIVE	84,114.34	
130	MDS/NSS	69,466.95	
131	FLEX MDS	<u>0.00</u>	
132	TOTAL	854,932,003.31	
133	UNKNOWN	<u>8,377,839.37</u>	
134	101-1000 TOTAL ACCOUNT 380	863,309,842.68	
135	101-2000 CIAC	(832,897.83)	
136	101-4000 Relocation Reimbursements	(17,664.36)	
137	106 Completed Construction not Classified	<u>275,408.41</u>	
138	Total Per Exhibit 8, Schedule 1	862,734,688.90	

140 **LEGEND for Headings**

141	BLANK	One Customer Per Tap
142	P	Primary Customer, No Master Valve
143	S	Secondary Customer, No Master Valve
144	*	Primary Customer, One Master Valve
145	+	Secondary Customer, One Curb Valve Controls All

**COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 16
METERS**

LINE NO.	RATE CODE	<u>RSS/RDS</u> \$	<u>SGS/DS-1</u> \$	<u>SGS/DS-2</u> \$	<u>SDS/LGSS</u> \$	<u>LDS/LGSS</u> \$	<u>FLEX</u>	<u>MLDS</u> \$	<u>TOTAL</u> \$
1	808	0.00	0.00	0.00	0.00	0.00	416.43	0.00	416.43
2	809	0.00	0.00	0.00	0.00	0.00	832.86	0.00	832.86
3	810	0.00	0.00	0.00	0.00	0.00	832.86	0.00	832.86
4	833	0.00	0.00	0.00	0.00	0.00	416.43	0.00	416.43
5	846	0.00	0.00	0.00	0.00	0.00	832.86	0.00	832.86
6	875	0.00	0.00	0.00	0.00	0.00	832.86	0.00	832.86
7	879	0.00	0.00	0.00	0.00	0.00	416.43	0.00	416.43
8	880	0.00	0.00	0.00	0.00	0.00	416.43	0.00	416.43
9	881	0.00	0.00	0.00	0.00	0.00	992.39	0.00	992.39
10	882	0.00	0.00	0.00	0.00	0.00	416.43	0.00	416.43
11	LG1	0.00	0.00	0.00	23,479.61	0.00	0.00	0.00	23,479.61
12	LG2	0.00	0.00	0.00	27,281.43	0.00	0.00	0.00	27,281.43
13	LG3	0.00	0.00	0.00	0.00	1,249.29	0.00	0.00	1,249.29
14	LG4	0.00	0.00	0.00	0.00	1,665.72	0.00	0.00	1,665.72
15	LG5	0.00	0.00	0.00	0.00	416.43	0.00	0.00	416.43
16	NSI	0.00	0.00	0.00	0.00	0.00	0.00	66.08	66.08
17	RCC	3,304.03	0.00	0.00	0.00	0.00	0.00	0.00	3,304.03
18	RC2	1,297,108.00	0.00	0.00	0.00	0.00	0.00	0.00	1,297,108.00
19	RS	23,428,034.26	0.00	0.00	0.00	0.00	0.00	0.00	23,428,034.26
20	RTC	3,352,842.98	0.00	0.00	0.00	0.00	0.00	0.00	3,352,842.98
21	SCC	0.00	1,206,481.07	0.00	0.00	0.00	0.00	0.00	1,206,481.07
22	SC2	0.00	0.00	544,693.66	0.00	0.00	0.00	0.00	544,693.66
23	SG2	0.00	0.00	1,150,472.02	0.00	0.00	0.00	0.00	1,150,472.02
24	SG3	0.00	13,534.40	0.00	0.00	0.00	0.00	0.00	13,534.40
25	SG4	0.00	0.00	17,732.40	0.00	0.00	0.00	0.00	17,732.40
26	SGS	0.00	3,733,521.72	0.00	0.00	0.00	0.00	0.00	3,733,521.72
27	TAG1	0.00	45,024.59	0.00	0.00	0.00	0.00	0.00	45,024.59
28	TAG2	0.00	0.00	141,658.84	0.00	0.00	0.00	0.00	141,658.84
29	TAG5	0.00	197,743.91	0.00	0.00	0.00	0.00	0.00	197,743.91
30	TAG6	0.00	0.00	472,212.06	0.00	0.00	0.00	0.00	472,212.06
31	TI4	0.00	0.00	0.00	57,728.33	0.00	0.00	0.00	57,728.33
32	TI8	0.00	0.00	0.00	0.00	19,315.31	0.00	0.00	19,315.31
33	TIB	0.00	0.00	0.00	111,331.38	0.00	0.00	0.00	111,331.38
34	TIF	0.00	0.00	0.00	0.00	28,666.00	0.00	0.00	28,666.00
35	TIG	0.00	0.00	0.00	0.00	2,082.15	0.00	0.00	2,082.15
36	TIH	0.00	0.00	0.00	0.00	416.43	0.00	0.00	416.43
37	ML1	0.00	0.00	0.00	0.00	0.00	0.00	416.43	416.43
38	ML5	0.00	0.00	0.00	0.00	0.00	0.00	832.86	832.86
39	TMA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
40	TMB	0.00	0.00	0.00	0.00	0.00	0.00	2,915.01	2,915.01
41	TMC	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
42	TM1	0.00	0.00	0.00	0.00	0.00	0.00	246.66	246.66
43	TM2	0.00	0.00	0.00	0.00	0.00	0.00	246.66	246.66
44	TM4	0.00	0.00	0.00	0.00	0.00	0.00	416.43	416.43
45	TM5	<u>0.00</u>	<u>0.00</u>	<u>0.00</u>	<u>0.00</u>	<u>0.00</u>	0.00	<u>416.43</u>	<u>416.43</u>
46	TOTAL	28,081,289.27	5,196,305.69	2,326,768.98	219,820.75	53,811.33	6,405.98	5,556.56	35,889,958.56
	SGT								8,839.18
	LIS								416.43
	SIS								416.43
	LOC								195,862.58
	LOF								<u>726.88</u>
Total									36,096,220.06
47	ALLOCATOR #16	78.244%	14.478%	6.483%	0.612%	0.150%	0.018%	0.015%	100.000%

Columbia Gas of Pennsylvania, Inc.
Account 385 Industrial Measurement Stations
As of November 30, 2024

Line No.	Co	PCID	PSID	Tar Rate	GTS Rate	Station No.	Tax District	Amt	Billing Rate	Rate Class
1	37	10034190010	501054825	SGT	TAG6	49103	30209	7,227.64	TAG6	SGSS2/SCD2/SGDS2
2	37	10132034047	400473027	SC2		4097	30272	1,504.40	SC2	SGSS2/SCD2/SGDS2
3	37	10132034051	400526772	SG2		810	30272	2,131.13	SG2	SGSS2/SCD2/SGDS2
4	37	10219299006	501195093	LG2		49394	732195	41,114.02	LG2	SDS/LGSS
5	37	10257973005	500030237	SG4		48810	1232756	9,184.43	SG4	SGSS2/SCD2/SGDS2
6	37	10375621158	500489101	SGT	TIB	47567	1333032	8,324.22	TIB	SDS/LGSS
7	37	10379912006	400498094	SG2		14628	1333032	1,501.31	SG2	SGSS2/SCD2/SGDS2
8	37	10416756005	500065176	SC2		47085	1333063	767.59	SC2	SGSS2/SCD2/SGDS2
9	37	10416756012	500416284	SG2		47469	1333025	17,948.01	SG2	SGSS2/SCD2/SGDS2
10	37	10421482002	500617033	SGT	TIB	49153	551504	44,715.05	TIB	SDS/LGSS
11	37	10422436002	400343911	SGT	TIB	46123	10155	8,766.90	TIB	SDS/LGSS
12	37	10468703002	400525452	SGT	TI4	48454	1292914	11,690.05	TI4	SDS/LGSS
13	37	10474924002	400303837	SGS		48831	1292988	967.26	SGS	SGSS1/SCD1/SGDS1
14	37	10501013005	400511506	SGT	TAG6	1276	511316	2,306.59	TAG6	SGSS2/SCD2/SGDS2
15	37	10502637002	400473325	LG2		1352	511314	4,068.67	LG2	SDS/LGSS
16	37	10506078005	400473264	SG2		1303	511314	1,557.22	SG2	SGSS2/SCD2/SGDS2
17	37	10512980003	800800458	SG2		1268	1292906	1,708.84	SG2	SGSS2/SCD2/SGDS2
18	37	11017807002	400032470	SGT	TI4	49445	1333068	22,686.73	TI4	SDS/LGSS
19	37	12983111001	400473518	SGT	TIB	661	1232704	23,392.95	TIB	SDS/LGSS
20	37	12983117003	400473502	SC2		49426	1232718	2,234.73	SC2	SGSS2/SCD2/SGDS2
21	37	12983124002	400473470	SG3		593	832295	916.28	SG3	SGSS1/SCD1/SGDS1
22	37	12983149001	800800461	SGT	TAG6	14545	1292906	5,738.98	TAG6	SGSS2/SCD2/SGDS2
23	37	12983153001	800800460	SGT	TI4	1414	1292906	5,172.69	TI4	SDS/LGSS
24	37	12983176001	400490973	SGT	TAG6	14491	1292969	3,560.97	TAG6	SGSS2/SCD2/SGDS2
25	37	12983177001	400484946	SGT	TI4	14324	1292906	855.29	TI4	SDS/LGSS
26	37	12983191002	400473426	SGT	TAG6	1444	511312	4,555.38	TAG6	SGSS2/SCD2/SGDS2
27	37	12983192001	400473425	SGT	TI4	1443	511396	3,807.64	TI4	SDS/LGSS
28	37	12983205001	400473388	SC2		4299	511314	2,637.30	SC2	SGSS2/SCD2/SGDS2
29	37	12983206002	500135694	SGT	TI4	1405	511314	2,319.74	TI4	SDS/LGSS
30	37	12983208001	400473368	SG2		4584	511314	2,944.67	SG2	SGSS2/SCD2/SGDS2
31	37	12983210001	400473364	SGT	TI4	4614	511314	2,618.96	TI4	SDS/LGSS
32	37	12983212001	400473357	SGT	TAG6	4548	511395	15,160.98	TAG6	SGSS2/SCD2/SGDS2
33	37	12983232001	400473302	SGT	TAG6	1335	511320	4,728.84	TAG6	SGSS2/SCD2/SGDS2
34	37	12983241018	400473429	SG2		49456	511318	75,128.44	SG2	SGSS2/SCD2/SGDS2
35	37	12983242001	400473279	SG2		1318	511303	2,708.28	SG2	SGSS2/SCD2/SGDS2
36	37	12983255002	400514019	SGT	TIB	1291	511395	7,185.12	TIB	SDS/LGSS
37	37	12983259002	400473238	SGT	TIB	1280	511396	247.56	TIB	SDS/LGSS
38	37	12983259002	500135609	SGT	TIB	1280	511396	247.56	TIB	SDS/LGSS
39	37	12983262001	400513746	SGT	TI8	44092	511363	(1,937.70)	TI8	LDS/LGSS
40	37	12983275001	400473402	SGT	TI4	1423	1112553	2,575.48	TI4	SDS/LGSS
41	37	12983276001	400473401	SGT	TI8	3382	1112553	12,914.58	TI8	LDS/LGSS
42	37	12983281001	400473412	SG2		1432	1112521	3,135.76	SG2	SGSS2/SCD2/SGDS2
43	37	12983287001	400473405	SGT	TIB	1426	1112521	6,824.22	TIB	SDS/LGSS
44	37	12983292002	400473346	LG1		1372	1112561	8,169.60	LG1	SDS/LGSS
45	37	12983297001	400473265	SGT	TIB	1302	1112569	4,329.43	TIB	SDS/LGSS
46	37	12983298001	400473267	SGT	TAG6	1305	1112569	1,771.37	TAG6	SGSS2/SCD2/SGDS2
47	37	12983301001	400473229	SGT	TI4	4252	1112553	1,853.55	TI4	SDS/LGSS
48	37	12983308005	400473411	SGT	TIB	1431	1112569	2,375.82	TIB	SDS/LGSS
49	37	12983314001	400473452	SGT	TAG6	1467	1292918	3,121.92	TAG6	SGSS2/SCD2/SGDS2
50	37	12983315001	400473443	SG2		4413	1292998	1,427.28	SG2	SGSS2/SCD2/SGDS2
51	37	12983318001	400473440	SGT	TAG6	1456	1292909	2,977.62	TAG6	SGSS2/SCD2/SGDS2
52	37	12983325001	400511507	SGT	TAG6	1403	1292914	2,761.08	TAG6	SGSS2/SCD2/SGDS2
53	37	12983331001	400473315	SGT	TAG6	4471	1292989	7,100.40	TAG6	SGSS2/SCD2/SGDS2
54	37	12983343001	400512909	SGT	TIB	3295	1252863	2,216.34	TIB	SDS/LGSS
55	37	12983349001	400473387	SG2		1408	1252858	1,774.66	SG2	SGSS2/SCD2/SGDS2
56	37	12983354001	400473366	SGT	TAG6	4044	1292919	1,330.60	TAG6	SGSS2/SCD2/SGDS2

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Line No.	Co	PCID	PSID	Tar Rate	GTS Rate	Station No.	Tax District	Amt	Billing Rate	Rate Class
57	37	12983355011	400473369	SGT	TIB	4469	1252855	2,663.14	TIB	SDS/LGSS
58	37	12983355011	400484838	SGT	TIB	14322	1252855	5,698.48	TIB	SDS/LGSS
59	37	12983355011	500163677	SGT	TIB	47388	1252855	76,140.47	TIB	SDS/LGSS
60	37	12983355011	500287938	SGT	TIB	47386	1252855	76,140.47	TIB	SDS/LGSS
61	37	12983359001	400473342	SGT	TIB	1364	1252858	1,770.49	TIB	SDS/LGSS
62	37	12983370001	400495171	SG2		3323	1252863	4,538.11	SG2	SGSS2/SCD2/SGDS2
63	37	12983403001	400472841	SGT	TIB	718	732195	1,809.43	TIB	SDS/LGSS
64	37	12983429002	400472946	SGT	TIB	807	70409	1,814.29	TIB	SDS/LGSS
65	37	12983433001	400512973	SGT	810	44075	732195	4,278.82	810	FLEX
66	37	12983434002	400472904	SGT	808	776	732153	93,547.00	808	FLEX
67	37	12983451001	400473180	SGT	TI4	997	732114	1,935.14	TI4	SDS/LGSS
68	37	12983453001	400473149	SGT	TAG5	974	732111	3,769.98	TAG5	SGSS1/SCD1/SGDS1
69	37	12983465001	400473060	SGT	TIB	890	732113	2,137.80	TIB	SDS/LGSS
70	37	12983467002	400473014	SGT	TIB	856	70409	6,095.11	TIB	SDS/LGSS
71	37	12983474002	400472983	SGT	TI8	832	732195	14,060.11	TI8	LDS/LGSS
72	37	12983480002	400472971	SG2		746	732195	2,473.69	SG2	SGSS2/SCD2/SGDS2
73	37	12983504001	400473099	SGT	TIB	924	70451	10,408.46	TIB	SDS/LGSS
74	37	12983508002	400508899	SGT	TI8	871	70424	6,374.99	TI8	LDS/LGSS
75	37	12983509011	400473189	SGT	TI8	1005	732158	7,244.26	TI8	LDS/LGSS
76	37	12983537001	400473198	LG2		1013	70453	2,943.45	LG2	SDS/LGSS
77	37	12983577003	400472935	SGT	TIB	801	70495	52,247.68	TIB	SDS/LGSS
78	37	12983589001	400472900	SGT	TAG6	772	70478	886.49	TAG6	SGSS2/SCD2/SGDS2
79	37	12983606002	400472820	SGT	TAG6	702	70495	23,896.62	TAG6	SGSS2/SCD2/SGDS2
80	37	12983611001	400503381	SGT	TI8	14705	70403	3,827.45	TI8	LDS/LGSS
81	37	12983623002	400473179	SGT	TAG6	996	310911	3,442.72	TAG6	SGSS2/SCD2/SGDS2
82	37	12983627001	400473107	SGT	TAG6	932	310956	498.89	TAG6	SGSS2/SCD2/SGDS2
83	37	12983630001	400526948	SG2		4420	333908	15,255.74	SG2	SGSS2/SCD2/SGDS2
84	37	12983644001	400512422	SGT	TI4	1155	1252896	8,235.06	TI4	SDS/LGSS
85	37	12983645004	400492992	SGT	TMB	1121	1252804	7,202.28	TMB	MDS/NSS
86	37	12983645004	500142415	SGT	TMB	1121	1252804	7,202.28	TMB	MDS/NSS
87	37	12983651001	400472750	SGT	TI8	1241	1252829	5,001.89	TI8	LDS/LGSS
88	37	12983663001	400505567	SGT	TAG2	14764	1252821	3,352.37	TAG2	SGSS2/SCD2/SGDS2
89	37	12983681002	400472637	SGT	TI4	1141	1252803	15,441.32	TI4	SDS/LGSS
90	37	12983693004	400506899	SGT	TI4	14766	1252821	4,992.09	TI4	SDS/LGSS
91	37	12983778004	400526322	SGT	TAG6	44903	30287	25,760.65	TAG6	SGSS2/SCD2/SGDS2
92	37	12983801005	500151204	SGT	846	1225	30205	6,621.55	846	FLEX
93	37	12983801005	800800501	SGT	846	1227	30257	477.96	846	FLEX
94	37	12983811001	400472633	SGT	TIB	1138	30298	34,962.92	TIB	SDS/LGSS
95	37	12983829003	400471809	SGT	TI8	4526	1333017	3,977.36	TI8	LDS/LGSS
96	37	12983875003	501090417	SGT	TIB	49141	30287	81,808.33	TIB	SDS/LGSS
97	37	12983915002	400472655	SGT	TIB	1159	30216	15,518.72	TIB	SDS/LGSS
98	37	12983936001	400473091	SGT	TI8	916	30225	13,874.35	TI8	LDS/LGSS
99	37	12983938001	400473088	SGT	TIF	913	30225	25,841.42	TIF	LDS/LGSS
100	37	12983938002	400473011	SGT	TI8	49348	30225	25,397.78	TI8	LDS/LGSS
101	37	12983939001	400473057	SGT	TIF	887	30225	259,819.28	TIF	LDS/LGSS
102	37	12983954001	400518548	SGT	TAG2	1016	30280	1,133.65	TAG2	SGSS2/SCD2/SGDS2
103	37	12983969001	400473144	SGT	TI8	4078	30280	6,739.92	TI8	LDS/LGSS
104	37	12983971001	400473142	SGT	TI4	968	30263	3,123.75	TI4	SDS/LGSS
105	37	12983982001	400473103	SGT	TI4	929	30272	356.76	TI4	SDS/LGSS
106	37	12983988005	501249841	LG2		49452	30209	296,072.43	LG2	SDS/LGSS
107	37	12983993001	400473045	LG1		881	30235	2,455.77	LG1	SDS/LGSS
108	37	12983994003	400473044	SGT	TI4	880	30235	2,280.48	TI4	SDS/LGSS
109	37	12984057001	400472794	SGT	TAG2	14003	70452	2,817.69	TAG2	SGSS2/SCD2/SGDS2
110	37	12984098001	400526718	SGT	TM1	45180	1252822	3,030.87	TM1	MDS/NSS
111	37	12984098003	400490002	SGT	TI8	14453	10154	2,352.32	TI8	LDS/LGSS
112	37	12984119001	400494178	SG2		1174	1252823	21,322.38	SG2	SGSS2/SCD2/SGDS2

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Line				Tar	GTS	Station	Tax		Billing	Rate
No.	Co	PCID	PSID	Rate	Rate	No.	District	Amt	Rate	Class
113	37	12984122008	400472639	SGT	TIB	48825	1252822	13,064.41	TIB	SDS/LGSS
114	37	12984129002	400472553	SGT	TIB	1070	1252807	3,851.22	TIB	SDS/LGSS
115	37	12984131002	500789128	SGT	TIB	48657	1252822	5,117.20	TIB	SDS/LGSS
116	37	12984147008	400520146	SGT	TIF	47452	1252807	223.81	TIF	LDS/LGSS
117	37	12984148002	500185413	SGT		49412	30241	45,918.09	SGT	INACTIVE
118	37	12984148003	400518885	SGT	TIB	44408	30241	7,603.27	TIB	SDS/LGSS
119	37	12984150004	501030792	SGT	875	49154	273860	1,099.50	875	FLEX
120	37	12984150004	800800371	SGT	875	4385	273804	6,048.49	875	FLEX
121	37	12984150007	501179703	SG2		49333	273860	1,099.50	SG2	SGSS2/SCD2/SGDS2
122	37	12984151020	400475666	SGT	TIF	1565	273860	287.79	TIF	LDS/LGSS
123	37	12984151020	400514859	SGT	TIF	48789	273860	1,099.50	TIF	LDS/LGSS
124	37	12984151020	400514976	SGT	TIF	48788	273860	1,099.50	TIF	LDS/LGSS
125	37	12984151020	400526997	SGT	TIF	45666	273860	1,099.50	TIF	LDS/LGSS
126	37	12984151020	500008214	SGT	TIF	48790	273860	1,099.50	TIF	LDS/LGSS
127	37	12984151020	500130476	SGT	TIF	45665	273860	1,099.50	TIF	LDS/LGSS
128	37	12984151020	500130460	SGT	TIF	45732	273804	697.05	TIF	LDS/LGSS
129	37	12984151020	500130474	SGT	TIF	48526	273860	1,099.50	TIF	LDS/LGSS
130	37	12984151020	500130459	SGT	TIF	48889	273860	1,099.50	TIF	LDS/LGSS
131	37	12984151020	500136322	SGT	TIF	45731	273804	697.05	TIF	LDS/LGSS
132	37	12984151020	500162068	SGT	TIF	45949	273860	1,099.50	TIF	LDS/LGSS
133	37	12984151020	500198356	SGT	TIF	46017	273804	697.05	TIF	LDS/LGSS
134	37	12984151020	500208315	SGT	TIF	46494	273804	697.05	TIF	LDS/LGSS
135	37	12984151020	500555580	SGT	TIF	48444	273860	1,099.50	TIF	LDS/LGSS
136	37	12984151020	500558423	SGT	TIF	48887	273860	1,099.50	TIF	LDS/LGSS
137	37	12984151020	500612327	SGT	TIF	48438	273804	697.05	TIF	LDS/LGSS
138	37	12984151020	500625771	SGT	TIF	48958	273860	586.51	TIF	LDS/LGSS
139	37	12984151020	500659013	SGT	TIF	48965	273860	1,099.50	TIF	LDS/LGSS
140	37	12984151020	500667297	SGT	TIF	48439	273804	697.05	TIF	LDS/LGSS
141	37	12984151020	500667298	SGT	TIF	48440	273860	(11,167.52)	TIF	LDS/LGSS
142	37	12984151020	500692603	SGT	TIF	48625	273860	1,099.50	TIF	LDS/LGSS
143	37	12984151020	500707423	SGT	TIF	48970	273804	697.05	TIF	LDS/LGSS
144	37	12984151020	500709556	SGT	TIF	48543	273860	1,099.50	TIF	LDS/LGSS
145	37	12984151020	500716291	SGT	TIF	48471	273860	1,099.50	TIF	LDS/LGSS
146	37	12984151020	500806647	SGT	TIF	48678	273860	1,099.50	TIF	LDS/LGSS
147	37	12984151020	500856054	SGT	TIF	48736	273804	697.05	TIF	LDS/LGSS
148	37	12984151020	500875536	SGT	TIF	48749	273804	697.05	TIF	LDS/LGSS
149	37	12984151020	500918034	SGT	TIF	48624	273860	1,099.50	TIF	LDS/LGSS
150	37	12984151020	500949336	SGT	TIF	48808	273860	1,099.50	TIF	LDS/LGSS
151	37	12984151020	500949337	SGT	TIF	48809	273860	1,099.50	TIF	LDS/LGSS
152	37	12984151020	800800356	SGT	TIF	4371	273860	1,099.50	TIF	LDS/LGSS
153	37	12984151020	800800357	SGT	TIF	4373	273860	1,099.50	TIF	LDS/LGSS
154	37	12984151020	800800358	SGT	TIF	4374	273860	1,555.96	TIF	LDS/LGSS
155	37	12984151020	800800359	SGT	TIF	4375	273860	1,235.30	TIF	LDS/LGSS
156	37	12984151020	800800360	SGT	TIF	4376	273860	1,099.50	TIF	LDS/LGSS
157	37	12984151020	800800361	SGT	TIF	4377	273860	825.56	TIF	LDS/LGSS
158	37	12984151020	800800362	SGT	TIF	4378	273860	1,152.36	TIF	LDS/LGSS
159	37	12984151020	800800364	SGT	TIF	4380	273860	550.88	TIF	LDS/LGSS
160	37	12984151020	800800365	SGT	TIF	4381	273804	697.05	TIF	LDS/LGSS
161	37	12984151020	800800366	SGT	TIF	4382	273860	1,099.50	TIF	LDS/LGSS
162	37	12984151020	800800367	SGT	TIF	4383	273860	2,705.00	TIF	LDS/LGSS
163	37	12984151020	800800369	SGT	TIF	14823	273860	(237.74)	TIF	LDS/LGSS
164	37	12984151020	800800370	SGT	TIF	45243	273804	697.05	TIF	LDS/LGSS
165	37	12984151020	800800354	SGT	TIF	49234	273860	1,099.50	TIF	LDS/LGSS
166	37	12984151070	500599616	SGT		48888	273860	1,099.50	SGT	INACTIVE
167	37	12984151071	500972343	SGT		48807	273804	697.05	SGT	INACTIVE
168	37	12984151071	501078814	SGT		49357	273860	1,099.50	SGT	INACTIVE

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Line No.	Co	PCID	PSID	Tar Rate	GTS Rate	Station No.	Tax District	Amt	Billing Rate	Rate Class
169	37	12984151071	501102376	SGT		49356	273860	1,099.50	SGT	INACTIVE
170	37	12984156009	400498964	SGT	TIF	14387	273821	5,213.78	TIF	LDS/LGSS
171	37	12984156009	501056289	SGT	TIF	49453	273821	9,141.40	TIF	LDS/LGSS
172	37	12984188002	400472449	SGT	TIF	4450	273804	353,710.72	TIF	LDS/LGSS
173	37	12984219008	400472431	LG2		294	551501	1,319.75	LG2	SDS/LGSS
174	37	12984219008	500165435	LG2		294	551501	1,319.75	LG2	SDS/LGSS
175	37	12984221002	400472381	SGT	TIB	1490	551501	5,370.70	TIB	SDS/LGSS
176	37	12984221004	501123144	SGT	TI8	49284	551501	1,956.54	TI8	LDS/LGSS
177	37	12984230001	400472414	SGT	TI4	1513	551554	1,524.62	TI4	SDS/LGSS
178	37	12984232001	400472408	NSI		1511	551511	1,250.65	NSI	MDS/NSS
179	37	12984233004	800800336	SGT	TI8	4507	551553	1,590.31	TI8	LDS/LGSS
180	37	12984235003	400503659	SGT	TI4	14732	551511	4,635.06	TI4	SDS/LGSS
181	37	12984235003	500232234	SGT	TI4	48041	551511	1,250.65	TI4	SDS/LGSS
182	37	12984245001	400514975	SG4		44087	10153	2,947.61	SG4	SGSS2/SCD2/SGDS2
183	37	12984247004	400472434	SGT	TIF	297	10109	7,068.70	TIF	LDS/LGSS
184	37	12984247004	400472433	SGT	TIF	4339	10109	4,963.02	TIF	LDS/LGSS
185	37	12984247004	800800335	SGT	TIF	14446	10109	4,078.78	TIF	LDS/LGSS
186	37	12984250006	400507411	SGT	TIB	3215	10154	2,625.29	TIB	SDS/LGSS
187	37	12984250006	400507413	SGT	TIB	3215	10154	2,625.29	TIB	SDS/LGSS
188	37	12984255005	400472391	SGT	TAG6	4293	10158	3,969.19	TAG6	SGSS2/SCD2/SGDS2
189	37	12984257002	400472388	SGT	TIF	3334	10120	389.22	TIF	LDS/LGSS
190	37	12984257002	500149512	SGT	TIF	1496	10120	7,979.81	TIF	LDS/LGSS
191	37	12984261001	400472371	SGT	TIF	3384	10114	417.56	TIF	LDS/LGSS
192	37	12984264001	400472364	SGT	TIB	1477	10117	2,125.64	TIB	SDS/LGSS
193	37	12984270006	400498095	SGT	TIB	14526	1333072	4,269.98	TIB	SDS/LGSS
194	37	12984273001	400522508	SGT	TIB	44530	10105	4,338.27	TIB	SDS/LGSS
195	37	12984275001	400472429	SGT	TIB	1523	10157	8,704.10	TIB	SDS/LGSS
196	37	12984276001	400511898	SGT	TIB	44051	10157	2,167.48	TIB	SDS/LGSS
197	37	12984281001	400472403	SC2		1507	10157	5,011.48	SC2	SGSS2/SCD2/SGDS2
198	37	12984282002	400472402	SGT	TI4	3499	10119	1,353.99	TI4	SDS/LGSS
199	37	12984283001	400472399	SGT	TI4	3187	10158	2,708.97	TI4	SDS/LGSS
200	37	12984291001	400472378	SGT	TAG6	1486	10157	3,434.35	TAG6	SGSS2/SCD2/SGDS2
201	37	12984293002	400472376	SGT	TMB	285	10109	13,185.56	TMB	MDS/NSS
202	37	12984293003	500925519	SGT		48785	10109	16,768.97	SGT	INACTIVE
203	37	12984296001	400472372	SGT	TAG6	1483	10104	2,598.74	TAG6	SGSS2/SCD2/SGDS2
204	37	12984299002	400472366	SGT	TI8	1479	10157	4,617.06	TI8	LDS/LGSS
205	37	12984299002	500220827	SGT	TI8	46090	10157	(4,696.74)	TI8	LDS/LGSS
206	37	12984318031	400051028	SGT	TI8	48031	1333063	767.59	TI8	LDS/LGSS
207	37	12984318031	400472328	SGT	TI8	3515	1333063	4,335.32	TI8	LDS/LGSS
208	37	12984318031	400514810	SGT	TI8	48034	1333063	767.59	TI8	LDS/LGSS
209	37	12984318031	500005922	SGT	TI8	48032	1333063	767.59	TI8	LDS/LGSS
210	37	12984318032	400494708	SGT	TAG6	48033	1333063	767.59	TAG6	SGSS2/SCD2/SGDS2
211	37	12984318032	400505362	SGT	TAG6	48677	1333063	767.59	TAG6	SGSS2/SCD2/SGDS2
212	37	12984321001	400472320	SGT	TAG6	3543	1333025	2,639.63	TAG6	SGSS2/SCD2/SGDS2
213	37	12984323001	400472318	SGT	TI8	3632	1333025	32,412.93	TI8	LDS/LGSS
214	37	12984324001	400472317	SC2		3542	1333025	964.28	SC2	SGSS2/SCD2/SGDS2
215	37	12984325001	400472316	SGT	TIF	3631	1333025	11,349.73	TIF	LDS/LGSS
216	37	12984325004	501256232	LG2		49420	1333025	76,778.56	LG2	SDS/LGSS
217	37	12984327001	400472263	SGT	TI4	4536	1333025	1,511.25	TI4	SDS/LGSS
218	37	12984329001	400526741	SGT	TMB	45205	1333025	29,437.80	TMB	MDS/NSS
219	37	12984343004	400490919	SGT	TIG	14417	1333063	14,980.65	TIG	LDS/LGSS
220	37	12984343004	500023117	SGT	TIG	48880	1333063	767.59	TIG	LDS/LGSS
221	37	12984343004	500535850	SGT	TIG	48881	1333063	767.59	TIG	LDS/LGSS
222	37	12984346001	400526951	SGT	TIB	44971	1333025	3,724.43	TIB	SDS/LGSS
223	37	12984351001	400472299	SGT	TI4	3527	1333025	4,553.41	TI4	SDS/LGSS
224	37	12984355002	400472293	LG1		3521	10103	1,321.13	LG1	SDS/LGSS

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Line				Tar	GTS	Station	Tax		Billing	Rate
No.	Co	PCID	PSID	Rate	Rate	No.	District	Amt	Rate	Class
225	37	12984357001	400472287	SGT	TIF	3625	1333063	135.13	TIF	LDS/LGSS
226	37	12984366001	400472272	SGT	TIB	3506	1333063	4,906.73	TIB	LDS/LGSS
227	37	12984368001	400472269	SGT	TIB	3504	1333063	1,341.44	TIB	SDS/LGSS
228	37	12984378001	400496892	SGT	TAG6	14565	1333017	2,669.44	TAG6	SGSS2/SCD2/SGDS2
229	37	12984382001	400493516	SGT	TIB	14532	1333017	16,243.58	TIB	SDS/LGSS
230	37	12984392002	400472214	LG2		3569	1333074	2,526.37	LG2	SDS/LGSS
231	37	12984392002	400472233	LG2		3649	1333074	8,902.25	LG2	SDS/LGSS
232	37	12984392002	800800313	LG2		3648	1333074	3,347.55	LG2	SDS/LGSS
233	37	12984433001	400474737	SGT	TAG6	14041	1333014	5,102.18	TAG6	SGSS2/SCD2/SGDS2
234	37	12984438005	400517692	SGT	TIB	14678	1333029	4,838.86	TIB	LDS/LGSS
235	37	12984438005	400526273	SGT	TIB	44876	1333029	5,910.79	TIB	LDS/LGSS
236	37	12984438005	800800325	SGT	TIB	3916	1333029	4,519.57	TIB	LDS/LGSS
237	37	12984440001	400472099	SGT	TIB	3909	1333032	(541.38)	TIB	SDS/LGSS
238	37	12984442001	400472096	SGT	TIG	14693	1333032	1,858.55	TIG	LDS/LGSS
239	37	12984443001	400472090	SGT	TIB	3901	1333095	1,466.35	TIB	SDS/LGSS
240	37	12984447001	400526359	SGT	TIB	3894	1333032	255,160.85	TIB	LDS/LGSS
241	37	12984448001	400472085	SGT	TIB	3893	1333027	932.88	TIB	LDS/LGSS
242	37	12984450007	500793520	SGT	TIF	48680	1333027	7,214.83	TIF	LDS/LGSS
243	37	12984453004	400505585	SGT	TIB	3881	1333029	14,041.32	TIB	SDS/LGSS
244	37	12984460001	400472065	SGT	TIB	3866	1333017	1,030.28	TIB	SDS/LGSS
245	37	12984475001	400472016	SGT	TIB	3799	1333027	77.96	TIB	SDS/LGSS
246	37	12984477004	800800315	SC2		3793	1333027	14.60	SC2	SGSS2/SCD2/SGDS2
247	37	12984484006	400467049	SGT	TIB	47453	1333083	121.41	TIB	SDS/LGSS
248	37	12984484006	400471998	SGT	TIB	14566	1333083	4,151.32	TIB	SDS/LGSS
249	37	12984484006	500151812	SGT	TIB	47456	1333083	121.41	TIB	SDS/LGSS
250	37	12984490001	400526586	SGT	TIF	4037	1333079	49,883.89	TIF	LDS/LGSS
251	37	12984493001	400471935	SGT	TAG2	4516	1333095	1,233.13	TAG2	SGSS2/SCD2/SGDS2
252	37	12984501001	400471867	SGT	TIF	4155	1333095	3,610.20	TIF	LDS/LGSS
253	37	12984507001	400471805	SGT	TIB	4556	1333014	5,773.32	TIB	SDS/LGSS
254	37	12984524001	400507001	SGT	TIB	14552	1333017	4,496.64	TIB	SDS/LGSS
255	37	12984533001	400494422	SGT	TIB	14521	1333027	1,675.67	TIB	LDS/LGSS
256	37	12984534001	400491763	SGT	TAG6	14383	1333029	113.15	TAG6	SGSS2/SCD2/SGDS2
257	37	12984538001	400496374	SGT	TIB	14554	1333095	272.28	TIB	SDS/LGSS
258	37	12984541001	400472240	SGT	TIB	4443	1333074	2,216.60	TIB	SDS/LGSS
259	37	12984542001	400499351	SC2		14534	1333029	2,404.34	SC2	SGSS2/SCD2/SGDS2
260	37	12984549001	400496547	SGT	TIB	14438	1333095	1,494.85	TIB	SDS/LGSS
261	37	12984569008	400472068	SGT	TIF	3869	1333029	15,669.22	TIF	LDS/LGSS
262	37	12984569008	400492606	SGT	TIF	47118	1333029	10,323.00	TIF	LDS/LGSS
263	37	12984569008	400505836	SGT	TIF	47356	1333029	11,603.87	TIF	LDS/LGSS
264	37	12984569008	400516746	SGT	TIF	47028	1333029	11,603.87	TIF	LDS/LGSS
265	37	12984592001	400471991	SGT	TIB	3698	1333069	9,772.77	TIB	LDS/LGSS
266	37	12984598001	400471984	SGT	TIB	3751	1333005	3,433.09	TIB	SDS/LGSS
267	37	12984606001	400471973	SGT	TIB	3736	1333026	7,338.45	TIB	SDS/LGSS
268	37	12984607002	400471965	SGT	TAG6	3728	1333027	4,576.34	TAG6	SGSS2/SCD2/SGDS2
269	37	12984614001	400471948	SGT	TIB	3719	1333035	6,531.56	TIB	SDS/LGSS
270	37	12984622002	400471919	SGT	TAG6	3765	1333032	1,060.19	TAG6	SGSS2/SCD2/SGDS2
271	37	12984624003	400471915	SGT	TIB	3763	1333032	4,434.71	TIB	SDS/LGSS
272	37	12984628004	400471893	SGT	TIB	3686	1333029	1,522.87	TIB	SDS/LGSS
273	37	12984661001	400526647	SGT	TAG6	45046	1333014	2,190.07	TAG6	SGSS2/SCD2/SGDS2
274	37	12984661003	400500358	SGT	TIB	14657	10101	20,352.12	TIB	SDS/LGSS
275	37	12984661004	500738669	SGT	TIB	48592	1333032	16,365.40	TIB	SDS/LGSS
276	37	13188422011	500079934	SGT	TIB	49385	273806	3,326.29	TIB	LDS/LGSS
277	37	13188422011	500325346	SGT	TIB	49384	273806	2,119.27	TIB	LDS/LGSS
278	37	13237020002	500135596	SGT	TIB	4638	511396	31,407.24	TIB	LDS/LGSS
279	37	13241895007	501021913	SGT	TIF	49028	30225	77,597.23	TIF	LDS/LGSS
280	37	13264345002	400520745	SG2		1306	1292913	3,173.68	SG2	SGSS2/SCD2/SGDS2

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281	37	13266182004	400473258	SGT	TMB	1296	1252858	2,294.81	TMB	MDS/NSS
282	37	13333833001	500159224	LG2		45928	551501	6,277.25	LG2	SDS/LGSS
283	37	13409908003	800800444	SGT	TI4	289	70406	2,190.25	TI4	SDS/LGSS
284	37	13503540001	500099035	SGT	TI4	45872	1252862	6,687.76	TI4	SDS/LGSS
285	37	13606384001	500209675	SGT	TI8	46079	1333028	14,613.78	TI8	LDS/LGSS
286	37	13629199001	500199977	SGT	TIF	46006	1112521	38,461.32	TIF	LDS/LGSS
287	37	13648145002	400473252	SGT	TI4	1289	1112521	24,071.02	TI4	SDS/LGSS
288	37	13676826001	500220820	SGT	TIF	46101	30243	27,319.26	TIF	LDS/LGSS
289	37	13801660001	500224592	SGT	TAG6	46122	1292998	7,734.44	TAG6	SGSS2/SCD2/SGDS2
290	37	13807449005	500843197	SGT	TAG6	48733	10160	10,929.56	TAG6	SGSS2/SCD2/SGDS2
291	37	13953098002	500268352	SG4		46701	511314	2,164.21	SG4	SGSS2/SCD2/SGDS2
292	37	13959263001	400473271	SGT	TI8	1309	1292977	8,591.82	TI8	LDS/LGSS
293	37	13968541002	500296548	SGT	TM3	46567	511324	286,814.93	TM3	MDS/NSS
294	37	14161126001	400472230	SGT	TIB	3588	1333034	3,800.39	TIB	SDS/LGSS
295	37	14203427002	400483822	SG2		14283	511304	3,499.71	SG2	SGSS2/SCD2/SGDS2
296	37	14238571001	500337814	SGT	TIF	46961	1333007	8,944.92	TIF	LDS/LGSS
297	37	14303963001	500391455	SGT	TAG6	47285	30260	12,062.59	TAG6	SGSS2/SCD2/SGDS2
298	37	14313747005	500338294	SGT	TAG6	47466	10155	12,751.38	TAG6	SGSS2/SCD2/SGDS2
299	37	14318082003	400519776	SGT	TIB	47451	1333032	9,668.71	TIB	SDS/LGSS
300	37	14344230001	500212008	SGT	TIB	47252	1252822	9,625.99	TIB	SDS/LGSS
301	37	14351364003	500354179	SGT	TIB	47333	591705	(9,801.11)	TIB	SDS/LGSS
302	37	14351364003	500371709	SGT	TIB	47605	591705	9,031.53	TIB	SDS/LGSS
303	37	14351364003	500690713	SGT	TIB	49040	591705	6,003.16	TIB	SDS/LGSS
304	37	14471914001	400526560	SGT	TIF	3908	1333032	12,192.53	TIF	LDS/LGSS
305	37	14492769002	500965975	SGT	TIB	49158	1112521	14,608.37	TIB	SDS/LGSS
306	37	14529317003	400472635	SGT	TI8	1139	1252856	13,623.23	TI8	LDS/LGSS
307	37	14529317003	800800373	SGT	TI8	14246	1252856	13,412.22	TI8	LDS/LGSS
308	37	14557113003	500054098	SGT	TAG6	48084	551501	28,878.63	TAG6	SGSS2/SCD2/SGDS2
309	37	14738217002	400473525	SGT	TI4	621	832206	7,909.77	TI4	SDS/LGSS
310	37	14860718003	400473280	SGT	TAG6	1313	511314	13,586.36	TAG6	SGSS2/SCD2/SGDS2
311	37	14958276004	501161721	SGT	TIB	49323	1112501	31,261.72	TIB	SDS/LGSS
312	37	14962898001	400504012	SC2		4067	10104	1,319.79	SC2	SGSS2/SCD2/SGDS2
313	37	14997023001	400472421	SGT	TAG6	3491	10157	1,735.53	TAG6	SGSS2/SCD2/SGDS2
314	37	15044341005	501362264	SG4		49477	1232756	15,088.13	SG4	SGSS2/SCD2/SGDS2
315	37	15096104001	500587558	SGT	809	47842	732195	6,753.16	809	FLEX
316	37	15096104002	501033523	SGT	809	49045	732195	44,763.53	809	FLEX
317	37	15096113001	500587559	SGT	833	47843	732195	30,296.36	833	FLEX
318	37	15107817004	500136220	SG4		1438	511314	1,515.02	SG4	SGSS2/SCD2/SGDS2
319	37	15120198003	501174545	LG2		49367	1333032	64,145.58	LG2	SDS/LGSS
320	37	15190290003	500990795	SGT	TIB	48924	511314	21,953.37	TIB	SDS/LGSS
321	37	15246690003	400478147	SG2		1122	1252821	10,996.30	SG2	SGSS2/SCD2/SGDS2
322	37	15310256001	400477241	SGT	TIB	3990	1333017	19.02	TIB	SDS/LGSS
323	37	15399043001	400473272	SG4		1310	1292913	1,878.81	SG4	SGSS2/SCD2/SGDS2
324	37	15409498002	400472801	SG2		686	30225	1,621.75	SG2	SGSS2/SCD2/SGDS2
325	37	15410029001	400524934	SG4		1465	511314	2,137.32	SG4	SGSS2/SCD2/SGDS2
326	37	15410029003	400526421	SG2		1368	511314	2,066.65	SG2	SGSS2/SCD2/SGDS2
327	37	15514483001	400473294	SG2		1329	1112521	1,067.76	SG2	SGSS2/SCD2/SGDS2
328	37	15514517001	500607489	SGT	TIF	48514	551504	29,232.95	TIF	LDS/LGSS
329	37	15614278001	500732771	SGT	TI4	48561	30223	5,320.06	TI4	SDS/LGSS
330	37	15630675002	501155646	SG2		49311	1292909	46,337.79	SG2	SGSS2/SCD2/SGDS2
331	37	15632066001	500494320	SGT	TIB	48533	1112512	10,803.64	TIB	SDS/LGSS
332	37	15674018001	500648810	SGT	TIF	48541	273801	99,366.60	TIF	LDS/LGSS
333	37	15878297001	500766884	SGT	TAG6	48455	1333007	12,533.19	TAG6	SGSS2/SCD2/SGDS2
334	37	15932079001	500755822	SGT	TI8	48661	511311	4,748.25	TI8	LDS/LGSS
335	37	16266565001	400518893	SGT	TI8	934	70495	(124.43)	TI8	LDS/LGSS
336	37	16316862001	400489632	SGT	TIB	48727	10103	23,457.97	TIB	SDS/LGSS

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Line No.	Co	PCID	PSID	Tar Rate	GTS Rate	Station No.	Tax District	Amt	Billing Rate	Rate Class
337	37	16450594001	400526719	SGT	TIB	48743	1333083	6,816.35	TIB	SDS/LGSS
338	37	16656334003	501222616	SG2		49396	511304	23,419.00	SG2	SGSS2/SCD2/SGDS2
339	37	16804444002	500146391	SGT	TI8	861	70495	5,786.00	TI8	LDS/LGSS
340	37	16804444008	500175309	SGT	TIB	49139	70495	9,018.14	TIB	SDS/LGSS
341	37	16919869001	500215263	SGT	TAG6	48787	1333095	28,276.31	TAG6	SGSS2/SCD2/SGDS2
342	37	16920048001	500959190	SGT	TIB	48797	511395	9,062.42	TIB	SDS/LGSS
343	37	17000719005	400496375	SGT	TAG6	14550	1333027	1,497.69	TAG6	SGSS2/SCD2/SGDS2
344	37	17037445001	500962866	SGT	TIB	48814	511306	6,626.36	TIB	SDS/LGSS
345	37	17097990001	400473352	SC2		4547	1252858	1,965.53	SC2	SGSS2/SCD2/SGDS2
346	37	17184483002	500193058	SGT	TIB	45604	732195	(5,006.09)	TIB	SDS/LGSS
347	37	17187387006	400471902	SGT	TI8	4178	1333032	3,370.20	TI8	LDS/LGSS
348	37	17260071005	400504725	SGT	TAG6	1363	1252858	1,728.41	TAG6	SGSS2/SCD2/SGDS2
349	37	17264884002	400500238	SGT	TIH	14403	1333032	6,310.54	TIH	LDS/LGSS
350	37	17297010001	400474558	SGT	TAG6	14055	1333035	5,282.49	TAG6	SGSS2/SCD2/SGDS2
351	37	17374299002	400473323	LG1		1351	511314	5,233.17	LG1	SDS/LGSS
352	37	17409498001	501027922	SGT	TIB	49021	1333095	11,988.70	TIB	SDS/LGSS
353	37	17509433003	501049268	SGT	TI8	49070	511306	13,305.02	TI8	LDS/LGSS
354	37	17556648001	500988325	LG1		49016	1252829	56,458.44	LG1	SDS/LGSS
355	37	17613477001	501040193	SC2		49048	832295	13,820.03	SC2	SGSS2/SCD2/SGDS2
356	37	17662964001	400472829	SGT	TIB	711	30252	8,688.26	TIB	SDS/LGSS
357	37	17692241009	501080986	SGT	TIB	49302	1333017	65,532.25	TIB	SDS/LGSS
358	37	17766386001	501049150	SGT	TI8	49088	1333014	35,922.76	TI8	LDS/LGSS
359	37	18505018001	400473396	SG2		3248	1292914	1,663.84	SG2	SGSS2/SCD2/SGDS2
360	37	18540737001	500487109	SGS		47705	1292909	31,397.65	SGS	SGSS1/SCD1/SGDS1
361	37	18660393001	501083309	SG2		40519	1252820	22,691.51	SG2	SGSS2/SCD2/SGDS2
362	37	18703892001	400505131	SGT	TI8	689	70477	20,627.81	TI8	LDS/LGSS
363	37	18776965001	400472097	SGT	TIF	3907	1333014	4,705.66	TIF	LDS/LGSS
364	37	18792064002	501099066	SGT	TAG6	49244	1333035	15,923.45	TAG6	SGSS2/SCD2/SGDS2
365	37	18836110001	400473205	SGT	TIB	1018	732111	3,880.29	TIB	SDS/LGSS
366	37	18885421001	500376080	SGT	TIB	49156	10119	16,178.78	TIB	SDS/LGSS
367	37	18897692003	400472409	SGT	TIB	1512	10160	1,660.38	TIB	SDS/LGSS
368	37	18985473001	501047288	SGT	TIB	49243	1333035	232.12	TIB	SDS/LGSS
369	37	18988904003	501281830	LG2		49425	70479	30,748.80	LG2	SDS/LGSS
370	37	19022293001	400473231	SG2		4575	511316	1,956.84	SG2	SGSS2/SCD2/SGDS2
371	37	19022293009	500132845	SG2		4575	511316	1,956.84	SG2	SGSS2/SCD2/SGDS2
372	37	19046540001	400508038	SGT	TIB	14064	1333017	866.71	TIB	SDS/LGSS
373	37	19074397001	501115733	SGT	TIB	49265	1333017	16,243.58	TIB	SDS/LGSS
374	37	19114953001	500688577	SGT	TI4	48544	511312	1,115.13	TI4	SDS/LGSS
375	37	19117144005	501102841	SGT	TI8	49282	732108	169.67	TI8	LDS/LGSS
376	37	19117144005	501104644	SGT	TI8	49270	732108	36,621.65	TI8	LDS/LGSS
377	37	19179996001	400472978	SGT	TIG	828	30272	15,084.85	TIG	LDS/LGSS
378	37	19193822001	501050977	SGT	TI4	49272	10103	14,333.13	TI4	SDS/LGSS
379	37	19252407003	800800378	SGT	TAG6	849	30234	2,745.65	TAG6	SGSS2/SCD2/SGDS2
380	37	19336466001	400501188	SGT	TAG2	45609	1333032	255,160.85	TAG2	SGSS2/SCD2/SGDS2
381	37	19443642001	400472814	LG2		697	70403	3,872.82	LG2	SDS/LGSS
382	37	19592009003	501149161	LG1		49340	1252822	15,220.72	LG1	SDS/LGSS
383	37	19623332001	400472345	SG2		3562	1333063	7,569.91	SG2	SGSS2/SCD2/SGDS2
384	37	19682099001	500296730	SGT	TIB	46707	511304	23,419.00	TIB	SDS/LGSS
385	37	19791817001	500175440	SGT	TAG5	45528	70452	31,255.79	TAG5	SGSS1/SCD1/SGDS1
386	37	19845214005	400472052	SGT	TIB	3847	1333032	7,154.80	TIB	SDS/LGSS
387	37	19854159001	501154755	SGT	TIB	49338	273804	1,887.55	TIB	SDS/LGSS
388	37	19854159002	501162824	SGT	TIB	49322	1333029	11,603.87	TIB	SDS/LGSS
389	37	19866613001	501025433	SGT	TIB	48841	190626	21,082.43	TIB	SDS/LGSS
390	37	19960243005	400484301	SG3		937	70452	4,620.19	SG3	SGSS1/SCD1/SGDS1
391	37	19968875005	800800311	SGT	TIB	14595	1333029	2,936.12	TIB	SDS/LGSS
392	37	20159378001	500153126	SGT	TI8	45642	70479	635.10	TI8	LDS/LGSS

Columbia Gas of Pennsylvania, Inc.
Account 385 Industrial Measurement Stations
As of November 30, 2024

Line No.	Co	PCID	PSID	Tar Rate	GTS Rate	Station No.	Tax District	Amt	Billing Rate	Rate Class
393	37	20231700001	400472742	SGT	TAG2	14101	1252807	5,736.00	TAG2	SGSS2/SCD2/SGDS2
394	37	20231700003	400472014	SGT	TIB	3795	1333027	8,044.15	TIB	SDS/LGSS
395	37	20271953001	500214064	SGT	TI4	47053	1252822	33,574.81	TI4	SDS/LGSS
396	37	20271953003	500459284	SGT	TAG6	47484	1252822	527.87	TAG6	SGSS2/SCD2/SGDS2
397	37	20352622001	400493366	SGT	TIF	14458	1333025	4,349.04	TIF	LDS/LGSS
398	37	20364142009	501345483	SGT	TIB	49469	10103	13,398.51	TIB	SDS/LGSS
399	37	20403776001	501228775	SG2		49390	10157	5,180.86	SG2	SGSS2/SCD2/SGDS2
400	37	20480473001	501093555	SGT	880	49361	1333014	467,690.79	880	FLEX
401	37	20480473002	400471977	SGT	TIB	4335	1333077	4,035.77	TIB	SDS/LGSS
402	37	20503074001	501173051	SGT	TIB	49398	1333029	2,105.64	TIB	SDS/LGSS
403	37	20540367001	501221207	SGT	810	49395	732195	32,565.34	810	FLEX
404	37	20556961001	400494798	SGT	TI8	14599	10160	8,510.15	TI8	LDS/LGSS
405	37	20665631001	400473191	SGT	TIF	1007	30225	5,761.56	TIF	LDS/LGSS
406	37	20669499001	501163330	SGT	TIB	49411	70452	31,255.79	TIB	SDS/LGSS
407	37	20688663001	400474751	SGT	TAG2	4509	30223	1,151.30	TAG2	SGSS2/SCD2/SGDS2
408	37	20721676001	400472176	LG2		3969	1333095	7,539.68	LG2	SDS/LGSS
409	37	20733007001	400473253	LG2		1290	1292977	9,793.67	LG2	SDS/LGSS
410	37	20733007003	400288865	SG4		46395	1292977	4,562.60	SG4	SGSS2/SCD2/SGDS2
411	37	20733007004	400289580	SG4		46393	1292977	4,562.60	SG4	SGSS2/SCD2/SGDS2
412	37	20757032003	400471986	SGT	TAG6	3754	1333017	1,646.10	TAG6	SGSS2/SCD2/SGDS2
413	37	20875641001	400473354	SG2		1377	1292913	936.34	SG2	SGSS2/SCD2/SGDS2
414	37	20910648001	400472256	LG3		3642	1333074	279.49	LG3	LDS/LGSS
415	37	20915520001	400490462	SGT	TIB	14386	10156	3,285.22	TIB	SDS/LGSS
416	37	21032523001	400493917	SGT	TMB	14046	70452	125,098.41	TMB	MDS/NSS
417	37	21032523002	400505175	SGT	882	14699	70468	23,377.51	882	FLEX
418	37	21051676001	400472854	SGT	TI4	733	70471	42.30	TI4	SDS/LGSS
419	37	21106925001	500922300	SGT	TIB	49427	551509	49,416.98	TIB	SDS/LGSS
420	37	21136528001	400473125	SC2		949	30231	2,662.32	SC2	SGSS2/SCD2/SGDS2
421	37	21143096003	400472012	SG2		3792	1333027	600.79	SG2	SGSS2/SCD2/SGDS2
422	37	21170009004	500635532	LG2		48654	1333004	4,591.38	LG2	SDS/LGSS
423	37	21175050001	400472009	SGT	TIB	3788	1333027	4,108.18	TIB	SDS/LGSS
424	37	21255328001	400472437	LG1		3304	10104	8,015.12	LG1	SDS/LGSS
425	37	21256476001	400498767	SGT	TI8	14635	10119	4,285.84	TI8	LDS/LGSS
426	37	21286391001	400472886	SG3		760	70471	3,829.02	SG3	SGSS1/SCD1/SGDS1
427	37	21334880001	500171349	SG2		45520	30205	11,235.36	SG2	SGSS2/SCD2/SGDS2
428	37	21337959001	400526191	SGT	TIF	44761	190613	52,867.22	TIF	LDS/LGSS
429	37	21350543001	500204877	SG2		48298	30272	5,399.51	SG2	SGSS2/SCD2/SGDS2
430	37	21368534001	800800442	SGT	TIB	4410	70458	1,250.67	TIB	SDS/LGSS
431	37	21401731001	400481256	LG1		1114	1252804	9,682.54	LG1	SDS/LGSS
432	37	21407113001	400510507	SGT	TAG2	926	70495	457.93	TAG2	SGSS2/SCD2/SGDS2
433	37	21407113003	500146350	SGT	TAG2	926	70495	457.93	TAG2	SGSS2/SCD2/SGDS2
434	37	21428899005	400507194	SG4		46075	1333063	767.59	SG4	SGSS2/SCD2/SGDS2
435	37	21428899006	500119649	SG4		45688	1333063	3,470.16	SG4	SGSS2/SCD2/SGDS2
436	37	21428899007	400472327	SG4		3636	1333063	4,224.76	SG4	SGSS2/SCD2/SGDS2
437	37	21494274001	400498570	SG2		49393	310911	12,392.69	SG2	SGSS2/SCD2/SGDS2
438	37	21496681003	400517972	SGT	TIB	44406	10160	3,203.39	TIB	SDS/LGSS
439	37	21503881001	400188814	LG1		45529	30243	11,446.47	LG1	SDS/LGSS
440	37	21588367001	400500097	SGT	TM4	14666	10119	980.04	TM4	MDS/NSS
441	37	21600670001	400471850	SG2		4149	1333035	290.07	SG2	SGSS2/SCD2/SGDS2
442	37	21600675002	800800314	SG2		4269	1333035	2,430.25	SG2	SGSS2/SCD2/SGDS2
443	37	21622700005	400498963	SGT	TI8	14518	10160	2,158.65	TI8	LDS/LGSS

Columbia Gas of Pennsylvania, Inc.
Account 385 Industrial Measurement Stations
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Line No.	<u>Co</u>	<u>PCID</u>	<u>PSID</u>	<u>Tar Rate</u>	<u>GTS Rate</u>	<u>Station No.</u>	<u>Tax District</u>	<u>Amt</u>	<u>Billing Rate</u>	<u>Rate Class</u>
					Total					
					<u>Cost</u>					<u>Percent</u>
444		RSS/RTS			0.00					0.000%
445		SGSS1/SCD1/SGDS1			76,756.17					1.353%
446		SGSS2/SCD2/SGDS2			987,008.80					17.382%
447		SDS/LGSS			2,012,214.75					35.437%
448		LDS/LGSS			1,884,713.08					33.192%
449		FLEX			<u>717,520.01</u>					<u>12.636%</u>
450		TOTAL BEFORE MLDS/NSS			5,678,212.81					100.000%
451		MDS/NSS			476,497.63					
452		INACTIVE			66,682.61					
453		FLEX MLDS			<u>0.00</u>					
454		TOTAL			6,221,393.05					

**COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 18
OTHER DISTRIBUTION O&M EXPENSE**

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	871.00	LOAD DISPATCHING	329,704	166,510	29,759	42,651	28,572	33,864	20	28,328
2	874.00	MAINS & SERVICES	19,228,767	11,449,385	1,654,635	1,990,754	1,306,018	1,539,840	961	1,287,174
3	875.00	M & R - GENERAL	854,431	431,513	77,121	110,529	74,045	87,759	51	73,413
4	876.00	M & R - INDUSTRIAL	379,824	-	5,139	66,021	134,598	126,071	-	47,995
5	878.00	METERS & HOUSE REGULATORS	2,578,562	2,068,755	344,109	147,391	13,950	3,378	335	645
6	879.00	CUSTOMER INSTALLATIONS	6,398,321	5,841,795	455,880	81,963	13,245	3,647	-	1,792
7	886.00	STRUCTURES AND IMPROVEMENTS	286,419	144,650	25,852	37,051	24,821	29,418	17	24,609
8	887.00	MAINS	13,348,810	6,741,549	1,204,864	1,726,802	1,156,808	1,371,056	801	1,146,930
9	889.00	M & R - GENERAL	1,792,209	905,119	161,765	231,840	155,313	184,078	108	153,987
10	890.00	M & R - INDUSTRIAL	128,755	-	1,742	22,380	45,627	42,736	-	16,270
11	892.00	SERVICES	2,765,810	2,525,240	197,064	35,430	5,725	1,577	-	774
12	893.00	METERS & HOUSE REGULATORS	484,174	388,448	64,613	27,675	2,619	634	63	121
13		TOTAL	48,575,786	30,662,965	4,222,544	4,520,487	2,961,341	3,424,058	2,356	2,782,036
14		ALLOCATOR #18	100.000%	63.124%	8.693%	9.306%	6.096%	7.049%	0.005%	5.727%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 19
O & M EXCLUDING GAS PURCHASED COST, UNCOLLECTIBLES, USP COSTS & A & G

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1		TOTAL PURCH GAS & UNDERGROUND STORAGE	246,333,586	183,024,797	27,217,383	29,674,509	6,107,933	102,997	205,967	-
2		TOTAL DISTRIBUTION O&M	62,623,056	39,530,164	5,443,673	5,827,726	3,817,663	4,414,250	3,059	3,586,523
3		TOTAL CUSTOMER ACCOUNTS	52,281,429	49,878,369	1,063,582	473,518	475,639	332,017	23,420	34,884
4		TOTAL CUSTOMER SERVICE & INFORMATION	2,681,113	2,561,195	101,652	16,504	1,431	260	29	43
5		TOTAL SALES	<u>3,861</u>	<u>3,541</u>	<u>272</u>	<u>44</u>	<u>4</u>	<u>1</u>	<u>0</u>	<u>0</u>
6		TOTAL	363,923,045	274,998,065	33,826,562	35,992,301	10,402,668	4,849,524	232,474	3,621,450
		LESS:								
7		GAS PURCHASED COST	245,031,485	182,057,441	27,073,448	29,517,621	6,075,656	102,450	204,869	-
8	904.00	UNCOLLECTIBLES-DIS REVENUE	8,672,658	8,119,950	281,081	271,628	-	-	-	-
9	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	815,066	(0)	1,092	17,989	434,626	307,508	21,632	32,220
10	904.00	UNCOLLECTIBLES-UNBUNDLED GAS	1,187,650	1,111,125	39,037	37,488	-	-	-	-
11	904.00	DIRECT USP UNCOLLECTIBLES	31,862,500	31,862,500	-	-	-	-	-	-
12	904.00	UNCOLLECTIBLES-DIS COVID-19 DEFERRAL	647,261	606,011	20,978	20,272	-	-	-	-
13	904.00	UNCOLLECTIBLES-GMB/GTS COVID-19 DEFERRAL	<u>60,830</u>	<u>0</u>	<u>82</u>	<u>1,343</u>	<u>32,437</u>	<u>22,950</u>	<u>1,614</u>	<u>2,405</u>
14		TOTAL	288,277,450	223,757,026	27,415,717	29,866,340	6,542,719	432,908	228,115	34,624
15		TOTAL	75,645,595	51,241,039	6,410,844	6,125,961	3,859,949	4,416,616	4,359	3,586,826
16		ALLOCATOR #19	100.000%	67.737%	8.475%	8.098%	5.103%	5.839%	0.006%	4.742%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2024

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

PAGE 1
WITNESS: K. L. Johnson

Line No.	Description	Alloc	Total Company	RS/RDS	SGS1/SCD1/SGDS1	SGS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	FLEX
			<u>Footage</u>	<u>Amount</u>	<u>Unit Cost</u>				
1	2" Pipe		15,221,557	459,405,532	\$30.18				
2	All Pipe		41,555,307	2,318,408,957					
3	Unit Cost of 2" x All Pipe Footage			1,254,139,165					
4	Customer Component			54.095%					
5	Demand Component			45.905%					
6	Number of Customers (Total Company excl MLDS)		449,931	412,605	31,651	5,137	447	79	12
7	Percent Customers		100.000%	91.703%	7.035%	1.142%	0.099%	0.018%	0.003%
8	Customer Component		54.095%	49.607%	3.806%	0.618%	0.054%	0.010%	0.002%
9	Design Day Volumes (Total Company excl MLDS)		793,600	448,700	84,000	110,000	56,300	51,800	42,800
10	Percent Design Day Volumes		100.000%	56.540%	10.585%	13.861%	7.094%	6.527%	5.393%
11	Demand Component		45.905%	25.954%	4.859%	6.363%	3.257%	2.996%	2.476%
12	Minimum System Allocation Factor		100.000%	75.559%	8.665%	6.981%	3.311%	3.006%	2.478%

**COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 21
HOUSE REGULATORS**

All Customers Excluding Low Pressure Customers

LINE NO.	Rate	RS/RTS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MLDS	FLEX	TOTAL
1	RC2	144,098	0	0	0	0	0	0	144,098
2	RS	2,936,825	0	0	0	0	0	0	2,936,825
3	RTC	394,178	0	0	0	0	0	0	394,178
4	LG1	0	0	0	540	0	0	0	540
5	LG2	0	0	0	370	0	0	0	370
6	LG3	0	0	0	0	12	0	0	12
7	LG4	0	0	0	0	12	0	0	12
8	NSI	0	0	0	0	0	12	0	12
9	SGS	0	194,437	0	0	0	0	0	194,437
10	SG2	0	0	24,984	0	0	0	0	24,984
11	SG3	0	382	0	0	0	0	0	382
12	SG4	0	0	460	0	0	0	0	460
13	EDSTIB1	0	0	0	0	0	0	0	0
14	TAG1	0	1,309	0	0	0	0	0	1,309
15	TAG2	0	0	2,529	0	0	0	0	2,529
16	TAG5	0	6,062	0	0	0	0	0	6,062
17	TAG6	0	0	11,285	0	0	0	0	11,285
18	TIB	0	0	0	2,468	0	0	0	2,468
19	TIF	0	0	0	0	312	0	0	312
20	TIG	0	0	0	0	36	0	0	36
21	TIH	0	0	0	0	12	0	0	12
22	TI4	0	0	0	1,900	0	0	0	1,900
23	TI8	0	0	0	0	492	0	0	492
24	TMA	0	0	0	0	0	0	0	0
25	TM1	0	0	0	0	0	12	0	12
26	TM4	0	0	0	0	0	24	0	24
27	TM3	0	0	0	0	0	12	0	12
28	TMB	0	0	0	0	0	72	0	72
29	802	0	0	0	0	0	0	0	0
30	808	0	0	0	0	0	0	12	12
31	809	0	0	0	0	0	0	24	24
32	810	0	0	0	0	0	0	24	24
33	831	0	0	0	0	0	0	0	0
34	833	0	0	0	0	0	0	12	12
35	840	0	0	0	0	0	0	0	0
36	845	0	0	0	0	0	0	0	0
37	846	0	0	0	0	0	0	12	12
38	847	0	0	0	0	0	0	0	0
39	848	0	0	0	0	0	0	0	0
40	857	0	0	0	0	0	0	0	0
41	868	0	0	0	0	0	0	0	0
42	873	0	0	0	0	0	0	0	0
43	875	0	0	0	0	0	0	12	12
44	876	0	0	0	0	0	0	0	0
45	877	0	0	0	0	0	0	0	0
46	879	0	0	0	0	0	0	12	12
47	880	0	0	0	0	0	0	12	12
48	881	0	0	0	0	0	0	12	12
49	882	0	0	0	0	0	0	12	12
50	SCC	0	59,794	0	0	0	0	0	59,794
51	SC2	0	0	12,176	0	0	0	0	12,176
52	Total	3,475,101	261,984	51,434	5,278	876	132	144	3,794,949
53	ALLOCATOR #21	91.573%	6.903%	1.355%	0.139%	0.023%	0.003%	0.004%	100.000%

**COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 22
AVERAGE ALLOCATORS 5 & 20**

LINE NO.		<u>RSS/RDS</u>	<u>SGS/DS-1</u>	<u>SGS/DS-2</u>	<u>SDS/LGSS</u>	<u>LDS/LGSS</u>	<u>FLEX</u>	TOTAL
1	ALLOCATOR #5	50.504%	9.027%	12.937%	8.667%	10.272%	8.593%	100.000%
2	ALLOCATOR #20	<u>75.559%</u>	<u>8.665%</u>	<u>6.981%</u>	<u>3.311%</u>	<u>3.006%</u>	<u>2.478%</u>	100.000%
3	TOTAL OF BOTH STUDIES	126.063%	17.692%	19.918%	11.978%	13.278%	11.071%	
4	AVERAGE OF BOTH STUDIES	63.032%	8.846%	9.959%	5.989%	6.639%	5.536%	100.000%
5	ALLOCATOR #22	63.032%	8.846%	9.959%	5.989%	6.639%	5.536%	100.000%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 23
METERS AND HOUSE REGULATORS - ACCOUNTS 381, 382, 383, & 384

LINE	ACCT.									
<u>NO.</u>	<u>NO.</u>	<u>ACCOUNT</u>	<u>TOTAL</u>	<u>RSS/RDS</u>	<u>SGS/DS-1</u>	<u>SGS/DS-2</u>	<u>SDS/LGSS</u>	<u>LDS/LGSS</u>	<u>MLDS</u>	<u>FLEX</u>
1	381.00	METERS	59,647,664	46,670,718	8,635,789	3,866,958	365,044	89,472	8,947	10,737
2	381.00	DIRECT - METERS - MLDS FLEX	16,319	-	-	-	-	-	-	16,319
3	381.10	AUTOMATIC METER READING	29,057,053	22,735,400	4,206,880	1,883,769	177,829	43,586	4,359	5,230
4	382.00	METER INSTALLATIONS	58,083,634	45,446,959	8,409,349	3,765,562	355,472	87,126	8,713	10,455
5	383.00	HOUSE REGULATORS	22,247,918	20,373,086	1,535,774	301,459	30,925	5,117	667	890
6	384.00	HOUSE REG INSTALLATIONS	3,546,998	3,248,093	244,849	48,062	4,930	816	106	142
7		TOTAL	172,599,586	138,474,256	23,032,641	9,865,810	934,200	226,115	22,792	43,772
8		ALLOCATOR #23	100.000%	80.229%	13.345%	5.716%	0.541%	0.131%	0.013%	0.025%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 24
LABOR

LINE	ACCT.		ALLOC	TOTAL							
NO.	NO.	ACCOUNT	FACTOR	COMPANY	RSS/RDS	SGS/DS-1	SGS/DS-2	SDS/LGSS	LDS/LGSS	MLDS	FLEX
1	816.00	WELLS	25	-	-	-	-	-	-	-	-
2	817.00	LINES	25	-	-	-	-	-	-	-	-
3	818.00	COMPRESSOR STATION	25	-	-	-	-	-	-	-	-
4	820.00	M & R	25	-	-	-	-	-	-	-	-
5	821.00	PURIFICATION	25	-	-	-	-	-	-	-	-
6	832.00	WELLS	25	-	-	-	-	-	-	-	-
7	834.00	COMPRESSOR STATION	25	-	-	-	-	-	-	-	-
8	836.00	PURIFICATION	25	-	-	-	-	-	-	-	-
9	870.00	SUPERVISION & ENGINEERING	18	6,038,399	3,811,679	524,918	561,933	368,101	425,647	302	345,819
10	871.00	LOAD DISPATCHING	13	265,302	133,986	23,946	34,320	22,991	27,249	16	22,795
11	874.00	MAINS & SERVICES	14	9,755,659	5,808,812	839,475	1,010,003	662,604	781,233	488	653,044
12	875.00	M & R - GENERAL	13	517,868	261,539	46,743	66,991	44,879	53,190	31	44,495
13	876.00	M & R - INDUSTRIAL	17	208,543	(0)	2,822	36,249	73,901	69,220	-	26,352
14	878.00	METERS & HOUSE REGULATORS	23	1,726,846	1,385,431	230,448	98,707	9,342	2,262	225	432
15	879.00	CUSTOMER INSTALLATIONS	15	4,471,118	4,082,220	318,567	57,275	9,255	2,549	-	1,252
16	880.00	OTHER	18	2,172,233	1,371,200	188,832	202,148	132,419	153,121	109	124,404
17	885.00	SUPERVISION & ENGINEERING	18	159,985	100,989	13,908	14,888	9,753	11,277	8	9,162
18	886.00	STRUCTURES AND IMPROVEMENTS	13	5,329	2,692	481	689	462	547	0	458
19	887.00	MAINS	13	3,564,260	1,800,058	321,710	461,073	308,879	366,085	214	306,241
20	889.00	M & R - GENERAL	13	1,190,929	601,455	107,493	154,059	103,206	122,320	72	102,325
21	890.00	M & R - INDUSTRIAL	17	37,381	0	506	6,498	13,247	12,407	-	4,723
22	892.00	SERVICES	15	1,143,449	1,043,991	81,471	14,648	2,367	652	-	320
23	893.00	METERS & HOUSE REGULATORS	23	298,366	239,376	39,817	17,055	1,614	391	39	75
24	894.00	OTHER EQUIPMENT	18	347,614	219,428	30,218	32,349	21,191	24,503	17	19,908
25	902.00	METER READING	6	230,445	211,323	16,210	2,632	228	42	5	7
26	903.00	CUSTOMER RECORDS AND COLLECTION EXPENSE:	6	1,695,582	1,554,883	119,267	19,364	1,679	305	34	51
27	920.00	SALARIES	19	3,887,107	2,633,009	329,432	314,778	198,359	226,968	233	184,327
28	921.00	OFFICE SUPPLIES & EXPENSES	19	380,179	257,522	32,220	30,787	19,401	22,199	23	18,028
29	923.00	OUTSIDE SERVICES EMPLOYED	19	-	-	-	-	-	-	-	-
30		TOTAL		38,096,593	25,519,592	3,268,483	3,136,444	2,003,877	2,302,167	1,814	1,864,216
31		ALLOCATOR #24		100.000%	66.987%	8.579%	8.233%	5.260%	6.043%	0.005%	4.893%

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

GROSS INTANGIBLE & DISTRIBUTION PLANT - GENERAL LEDGERS 101, 106 AND 107 – PAGE 3

INTANGIBLE PLANT - PAGE 3 (101-106-107)

Accounts 301, 302 and 303

Intangible plant was allocated on the basis of Distribution plant excluding Accounts 375.7, 375.71 and 387, Factor No. 11, due to its indirect relationship with all other plant.

UNDERGROUND STORAGE PLANT - PAGE 3 (101-106-107)

Accounts 350 through 355

Underground Storage Plant was allocated using Factor No. 25 – Sales and CHOICE Transportation activity for the historic test year reflecting its peaking support for sales and CHOICE customers.

DISTRIBUTION PLANT - PAGE 3 (101-106-107)

Account 375.60

Structures for large customers, not directly assigned, were allocated using Factor No. 17 since these structures involve house measuring and regulating stations serving the larger customer groups only.

Account 376 – Mains

Non-directly assigned mains were allocated by rate schedule based on the weighting of design day and annual throughput, Factor No. 5, for the peak and average study. For the Customer-Demand study, such investment was based on Factor No. 20, which provides a customer component based on a 2” “Minimum System” with the remaining portion assigned on design-day. For the Average study, Factor No. 5 and Factor No. 20 are averaged to assign the Mains costs to the various rate schedules. Please see Exhibit KLJ-1 for a detailed description of Factor Nos. 5 and 20.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Direct Mains

Mains for Main Line Delivery Service ("MLDS") were identified by reviewing the Company's maps and accounting records and directly assigned to this class. Due to the unique characteristics of these customers, i.e., proximity to an interstate pipeline company and minimal Company investment, the investment was directly assigned.

Mains - Related Accts

Accounts related to/or supports the mains gas plant account were allocation on Factor No. 5 under the Peak and Average study, Factor No. 20 under the Customer-Demand study, and Factor No. 22 under the Average study since these accounts directly support the mains investment. The mains-related accounts generally include the follow gas plant accounts: 374.10, 374.20, 374.30, 374.40, 374.41, 374.50, 375.20, 375.31, 375.40, 375.80, 378.10, 378.20, 378.30, 379.10 and 379.11.

Direct Mains - Related Accts

Similarly to the Mains - Related Accounts above, these are accounts that support the mains that were directly assigned to MLDS and include accounts 374.40, 374.50, 375.40, and 378.20. Like direct – mains, the amounts were identified from the Company's maps and accounting records and directly assigned.

Account 380 - Services

Account 380 - Services was assigned by rate schedule based on each customer's service size and the average unit cost of that size service on the Company's plant accounting records. This methodology represents virtually a direct assignment of costs to the various rate classes.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Like mains, services for MLDS were identified by reviewing the Company's maps and accounting records and directly assigned to this class. Due to the unique characteristics of these customers, i.e., proximity to an interstate pipeline company and minimal Company investment, the investment was directly assigned.

Accounts 381 and 382

Meters and Meter Installations were allocated using Factor No. 16, which was based on an actual inventory of meters installed on customer premises as explained in Statement 6. This methodology represents a direct assignment of costs to the various rate classes.

Accounts 383 and 384

House Regulators and House Regulator Installations were allocated using Factor No. 21 which is based on number of customers by rate class that are not served from a low pressure main. Because customers served off low pressure mains do not require a House Regulator, those customers are not included in the allocation factor as explained in Statement No. 6.

Account 385

Industrial Measuring and Regulating Stations were allocated using Factor No. 17, which was based on a review of Columbia's records as explained in Statement 6. Measuring stations were segregated by rate schedule by identifying measuring stations in the plant accounting records with the individual customers in the Distributive Information System ("DIS"). This methodology represents a direct assignment of costs to the various rate classes.

Dist Plant Excl Other Allocated

This investment consists of gas plant accounts 375.70, 375.71 and all 387 and was allocated to the various rate schedules using Factor No. 11. Factor No. 11 was based on distribution plant specifically assigned and was used to assign general investment and costs that support the distribution system.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

General Plant

General plant includes items such as general tools (cars, trucks, backhoes, etc), communication equipment, office furniture and fixtures, and other miscellaneous equipment. Like general distribution plant, this plant investment supports the delivery of natural gas and, therefore, Factor No. 11 was used to assign the investment.

RESERVE FOR DEPRECIATION - PAGE 4

Depreciation Reserve was calculated on an account-by-account basis using the same allocation factors that were used to allocate all gross plant accounts.

DEPRECIATION & AMORTIZATION EXPENSE and NET NEGATIVE SALVAGE - PAGE 5

Depreciation and amortization expense was allocated by gas plant account on the same allocations as the Gross Original Cost. Amortization of net negative salvage was allocated using Factor 11 based on its remediation of distribution type facilities.

OPERATING REVENUE AT CURRENT AND PROPOSED RATES - PAGE 6

Sales and Transportation Revenue

Sales and transportation revenue was directly assigned as presented in Exhibit No. 103 for the fully projected future test year and supported by Witness Battig.

Accounts 487

Forfeited discounts were allocated using Factor No. 10, which was developed from actual forfeited discounts billed by rate class during the historic test year the twelve months ended November 30, 2024.

Accounts 488, 493 and 495

Miscellaneous Revenue and Other revenue were allocated using Factor No. 6 - Average Number of Customers since costs incurred throughout these accounts are directly related to the customers served. Rent Revenue was allocated using Factor No. 11 because the rent is derived

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

mostly from the rent of Company-owned office buildings, making the use of the Distribution Plant allocator appropriate.

OPERATING EXPENSES – PURCHASED GAS EXPENSES - PAGE 7

Gas purchased cost

These costs were directly assigned based on revenue for the fully projected future test year as presented in Exhibit No. 103.

Account 807

Gas Purchase Expense and Gas Procurement Expenses were allocated using Factor No. 4, which is based on the direct assignment of gas costs. Factor No. 4 was used reflecting the relationship of these costs to gas purchase costs. Gas purchase expense related to the gas procurement activity was also allocated using Factor No. 4.

OPERATING EXPENSES – UNDER STORAGE EXPENSES - PAGE 7

Accounts 814 through 837

Underground Storage Plant Expense was allocated using Factor No. 25 – Sales and CHOICE Transportation.

DISTRIBUTION EXPENSES – OPERATIONS - PAGE 7

Accounts 870, 880, 881

General costs for supervision and engineering, rents and other items of the distribution function were allocated using Factor No. 18, Other Distribution Expense, because these costs benefit customers in the way that all other distribution costs provide benefit.

Account 871

Distribution Load Dispatch Expenses were allocated on Factor No. 13 – Direct Plant – Mains because these are costs incurred monitoring and directing the flow of gas through the distribution system.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 874

Mains and Services Operation Expenses (a dual function account) were allocated on Factor No. 14 – Composite Direct Plant - Mains and Services combined.

Accounts 875

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures because these costs are incurred in direct relation with mains.

Accounts 876

Expenses for Measurement and Regulator Station Equipment - Industrial were allocated using Factor No. 17 – Direct Assignment – IND M&R - because these costs are incurred in direct association with the stations in Account 385.

Accounts 878 and 879

Meters & House Regulators Expenses were allocated using Factor No. 23, which was based on an actual inventory of meters and house regulators installed on customer premises as explained in Statement No. 6. This methodology represents virtually a direct assignment of costs to the various rate classes. Expenses for Customer Installations were allocated using Factor No. 15, because these expenses are related to the customer service lines.

DISTRIBUTION EXPENSES – MAINTENANCE - PAGE 7

Accounts 885 and 894

General costs for supervision and engineering and maintenance costs of other equipment of the distribution function were allocated using Factor No. 18 - Other Distribution Expense - because these costs benefit customers in the same way that all other distribution costs provide benefit.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Account 886

Structures and Improvements Expense was allocated using Factor No. 13, reflecting the spread of Account 376 Mains among all customer classes, because these plant and expense functions are directly related.

Account 887

Mains Maintenance Expense was allocated using Factor No. 13, which reflects the spread of Account 376 Mains among all customer classes, because plant and expense functions are directly related.

Accounts 889

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures because these costs are incurred in direct relation with mains.

Accounts 890

Expenses for Measurement and Regulator Station Equipment - Industrial were allocated using Factor No. 17 - Direct Assignment – IND M&R - because these costs are incurred in direct relation with the stations in Account 385.

Account 892

Expenses for Services were allocated using Factor No. 15, which was based on size of service and size of customer as explained above under Gas Plant Account 380 – Services and in Statement No. 6.

Account 893

Meters & House Regulators Expenses and Customer Installations were allocated using Factor No. 23, which was based on a weighted average cost of meters and house regulators as explained in Statement No. 6.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

**CUSTOMER ACCOUNTS, CUSTOMER SERVICE AND INFORMATIONAL AND SALES
EXPENSES - PAGE 8**

Account 904 – Uncollectibles – DIS Revenue & Uncollectibles GMB/GTS Revenue and Covid-19 Deferral

These cost categories represent traditional bad debts. They have been separated between the residential and commercial classes of customers and allocated based on the historical charge-offs and revenue, related to each, as included in Factor No. 7 for DIS and Factor No. 8 for GMB/GTS, respectively.

Account 904 Uncollectibles – Unbundled

These costs were directly assigned to each rate schedule matching revenue for the fully projected future test year, as presented in Exhibit No. 103 for the Merchant Function Charge.

Account 904 – Direct USP Uncollectibles

These uncollectibles are directly related to the Company's Customer Assistance Program ("CAP") available to residential customers and are recoverable from the residential class whether sales or delivery service. The amounts shown are reflected in revenue for the fully projected future test year as presented in Exhibit No. 103.

Customer Accounts

Customer Accounts includes meter reading, customer records, and credit and collection activities recorded in accounts 901 through 903, 905, and 921. These costs were allocated using Factor No. 6, Average Number of Customers, because they are directly related to the number of customers served. Interest on Customer Deposits was allocated using Factor No. 9, because the interest is directly related to the amount of customer deposits.

Customer Service Information

Customer Service and Informational Costs are reflected in accounts 907 through 910 plus related costs in 921 and 931. These costs were allocated using Factor No. 6, because all customers

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

may benefit except account 908 – Direct USP/LIURP/HEEP and 908 – Rider EE – Energy Efficiency. These costs include the recovery of specific customer programs benefiting residential customers. The amounts reflect the recovery included in revenue as presented in Exhibit No. 103 for the fully forecasted rate year.

Sales Expense

Sales expenses, accounts 912 and 913, were allocated using Factor No. 6, Average Number of Customers, because these activities directly support customers served.

ADMINISTRATIVE AND GENERAL EXPENSES - PAGE 8

Admin. & General Expenses (Line 37)

General Office Expenses, and to a lesser degree, District and Local Office Expenses in this function classification, plus Company-wide expenses excluding Employee Benefits, Account 926, such as Injuries and Damages, Insurance, and Regulatory Commission Expense, were all allocated using Factor No. 19 - Total Operation & Maintenance Excluding Gas Purchased, A & G, Uncollectibles and USP rider costs. These costs are regarded as overhead to the entire Company operation and, therefore, follow the allocation of the aggregate of all other previously allocated O&M costs. Employee Pensions & Benefits, Account 926, was allocated on Factor No. 24, Labor, because they are directly related to company labor.

TAXES OTHER THAN INCOME - PAGE 9

Property taxes are directly related to tangible property and, accordingly, have been allocated based on Factor No. 11 - Distribution Plant excluding Other, due to a direct relationship with Plant in Service. Similarly, PA Capital Stock and License and Franchise Taxes were allocated using Factor No. 11, as they are also related to Plant in Service. Federal Unemployment Insurance, State Unemployment Insurance and F.I.C.A. (payroll based taxes) are all labor-related and, accordingly,

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

have been allocated based on Factor No. 24 – Labor. State Sales and Use Tax and Other Taxes were allocated using Factor 19 because these taxes are generally related to the purchase of supplies.

RATE BASE SUMMARY - PAGE 10

Account 154

Materials and Supplies were allocated based on No. Factor 11, Distribution Plant Excluding Other, reflecting the primary future use of such inventory.

Account 164 & 117

Gas Stored Underground, both current and long term, was allocated based on Factor No. 25, Sales and CHOICE Transportation, reflecting the support of these customers in meeting their design day and seasonal requirements.

Account 165

Prepayments consist primarily of commission fees and corporate insurance, therefore they were allocated using Factor No. 19, Total O&M Excluding Gas Purchased Costs, A&G, Uncollectibles, and USP Rider Costs. The exception being Cloud Based Assets that, like Intangible Plant was allocated on the basis of Distribution Plant excluding Accounts 375.7, 375.71 and 387, Factor No. 11, due to its indirect relationship with all other plant.

Accounts 190, 254, 282 and 283

All deferred income taxes included in rate base are plant related and, therefore, Factor No. 12, Gross Plant, was used.

Account 235

Customer Deposits were allocated using Factor No. 9, Direct Assignment – Customer Deposits.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Accounts 252 and 186

Customer advances, other deferred credit and materials and supplies were allocated using Factor No. 11 - Distribution Plant Excluding Other, due to their direct relationship with all other gas plant accounts.

FEDERAL AND STATE INCOME TAX - PAGE 11

All of the Company's tax adjustments over book are plant related, i.e., tax depreciation over book depreciation and, therefore, the tax deductions were allocated using Factor No. 12, Gross Plant.

In calculating the Federal and State income taxes for each rate schedule, the effective Federal and State income tax rates were used. Income taxes were calculated for each rate class.

Columbia Gas of Pennsylvania, Inc.
Intra Class Adjustment from SGDS to SGSS and SCD at Proposed ROE of 11.35%
For the 12 Months Ending December 31, 2026

Ln. No.	Item	Total	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	Account 117	3,794,693	2,780,941	446,977	472,705	87,619	1,480	4,971
2	Account 164	<u>50,418,870</u>	<u>36,949,469</u>	<u>5,938,839</u>	<u>6,280,679</u>	<u>1,164,172</u>	<u>19,663</u>	<u>66,049</u>
3	Allocated Storage Per ACOS Study using Allocation Factor #25	54,213,563	39,730,410	6,385,816	6,753,384	1,251,791	21,143	71,020
4	Sales & CHOICE Transportation (Dth)	<u>45,674,063.0</u>	<u>33,471,971</u>	<u>5,379,789</u>	<u>5,689,846</u>	<u>1,054,673</u>	<u>17,784</u>	<u>60,000</u>
5	Factor 25 Allocation of Storage	<u>100%</u>	<u>73.285%</u>	<u>11.779%</u>	<u>12.457%</u>	<u>2.309%</u>	<u>0.039%</u>	<u>0.131%</u>
6	Pre-Tax as Filed	10.82%	10.82%	10.82%	10.82%	10.82%	10.82%	10.82%
7	Revenue Requirement related to storage assigned to rate schedule (Ln. 6 * Ln. 7)	<u>5,863,433</u>	<u>4,297,017</u>	<u>690,654</u>	<u>730,408</u>	<u>135,387</u>	<u>2,287</u>	<u>7,681</u>
8	Rate Per Dth	<u>0.1284</u>						
9					Included			
10		Total	% of	In Proposed		Redistributed		
11		<u>DTH</u>	<u>Total</u>	<u>Rates</u>	<u>Ratio</u>	<u>Per Settlement</u>		
12								
13	SGSS1 - Subject to Storage	3,983,415.9	70.870%	489,466	0.7405	21,889		
14	SCD1 - Subject to Storage	1,396,372.8	24.840%	171,558	0.2595	7,671		
15	SGDS1 - Not Subject to Storage	<u>240,725.2</u>	<u>4.280%</u>	<u>29,560</u>		<u>(29,560)</u>		
		<u>5,620,513.9</u>	<u>99.990%</u>	<u>690,585</u>		0		
16					Included			
17		Total	% of	In Proposed		Redistributed		
18		<u>DTH</u>	<u>Total</u>	<u>Rates</u>	<u>Ratio</u>	<u>Per Settlement</u>		
19								
20	SGSS2 - Subject to Storage	3,825,270.3	42.320%	309,109	0.6723	181,984		
21	SCD2 - Subject to Storage	1,864,575.7	20.630%	150,683	0.3277	88,705		
22	SGDS2 - Not Subject to Storage	<u>3,350,063.1</u>	<u>37.060%</u>	<u>270,689</u>		<u>(270,689)</u>		
		<u>9,039,909.1</u>	<u>100.010%</u>	<u>730,481</u>		0		

Unitized Returns at Current Rates and Proposed Rates

<u>Ln.</u>	<u>Study (Mains Allocation Method)</u>	<u>RSS/RDS</u>	<u>SGS/DS-1</u>	<u>SGS/DS-2</u>	<u>SDS/LGSS</u>	<u>LDS/LGSS</u>	<u>MLDS</u>	<u>FLEX</u>
1	Peak & Average Current Rates	1.19	1.11	1.12	1.14	0.40	38.05	(0.53)
2	Peak & Average Proposed Rates	1.18	1.10	1.10	1.11	0.47	28.83	(0.40)
3	Customer/Demand Current Rates	0.74	1.16	2.49	3.90	2.87	38.05	(0.23)
4	Customer/Demand Proposed Rates	0.76	1.16	2.33	3.57	2.76	28.83	(0.17)
5	Average of P/A & C/D Current Rates	0.93	1.13	1.62	1.92	0.97	38.05	(0.46)
6	Average of P/A & C/D Proposed Rates	0.94	1.13	1.55	1.81	1.00	28.83	(0.35)

Columbia Gas of Pennsylvania , Inc
Calculation of Gas Procurement Charge
Proposal to Maintain Current Rate⁽¹⁾

Exhibit KLJ-6
Page 1 of 1

		<u>Rate Case Calculation</u>	
		<u>Amount</u>	<u>Rate</u>
1 Labor and Benefits ⁽²⁾			
2	Accounting Support	\$4,531.43	
3	Gas Supply Support	\$203,428.42	
4	Legal Support	\$5,685.68	
5	Regulatory Support	\$84,506.70	
6	Treasury Support	\$11,999.46	
7	Total Labor and Benefits (Line 2 + Line 3 + Line 4 + Line 5 + Line 6)	\$310,151.69	
8	Outside Services - Legal Support	\$61,000.00	
9	Information Technology Systems Maintenance		
10	Gas Source	\$49,021.00	
11	% of customers taking Sales Service	80.00%	
12	Cost allocated to Sales Service Customers (line 10 * Line 11)	\$39,216.80	
13	TOTAL (line 7 + line 8 + line 12)	\$410,368.49	
14	Total Sales (Therms)	362,959,766 ⁽³⁾	
15	Gas Procurement Charge (Line 13 / Line 14)		\$0.00113 per / therm
16	Gas Procurement Charge (Line 15 * 10)		\$0.01130 per / Dth

(1) The Company proposes to maintain the current Gas Procurement Charge as the overall fundamentals of the calculation have not changed. The current charge was calculated in the 2021 Rate Case.

(2) Labor charges include payroll, benefits and taxes.

(3) 2021 Rate Case - Fully Projected Future Test Year Gas Service Sales per Exhibit 103, Sch. 1, Page 14, Line 49, less Rate NSS Sales as NSS is not subject to GPC.

Columbia Gas of Pennsylvania , Inc
Calculation of Residential & Small Commercial Energy Efficiency Rider
For the 12 Months Ended December 31, 2026

Exhibit KLJ-7
Page 1 of 1

	Amount	Rate
1 Residential Program Costs (2026)	\$1,963,496.00	
2 Residential Sales Service (RSS) - Volumes (Dth)	27,293,489 ⁽¹⁾	
3 Residential Distribution Service Choice (RDS) - Volumes (Dth)	3,683,081 ⁽¹⁾	
4 Total Residential - Volumes (Dth)	<u>30,976,570</u>	
5 Residential Energy Efficiency Rider Rate (per/ Dth) (Line 1 / Line 4)		\$0.06340 per / Dth
6 Residential Energy Efficiency Rider Rate (per/ Therm)		\$0.00634 per / Therm
7 Small Commercial Program Costs (2026)	\$ 503,366.00	
8 Small General Sales Service (SGSS) (≤ 6,440 Therms Annually) (Dth)	3,983,416 ⁽¹⁾	
9 Small General Sales Service (SGSS) (> 6,440 to ≤ 64,400 Therms Annually) (Dth)	3,825,270 ⁽¹⁾	
10 Small Commercial Distribution (Choice) (SCD) ≤ 6,440 Therms (Dth)	1,396,373 ⁽¹⁾	
11 Small Commercial Distribution (Choice) (SCD) > 6,440 to ≤ 64,400 Therms (Dth)	1,864,576 ⁽¹⁾	
12 Small General Distribution Service (SGDS) ≤ 6,440 Therms (Dth)	240,725 ⁽¹⁾	
13 Small General Distribution Service (SGDS) > 6,440 to ≤ 64,400 Therms (Dth)	3,350,063 ⁽¹⁾	
14 Total Small Commercial - Volumes (Dth)	<u>14,660,423</u>	
15 Small Commercial Energy Efficiency Rider Rate (per/ Dth) (Line 7 / Line 14)		\$0.03430 per / Dth
16 Small Commercial Energy Efficiency Rider Rate (per/ Therm)		\$0.00343 per / Therm

(1) Fully Projected Future Test Year Volumes per Exhibit 103, Sch. 1

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
RAYMOND A. BRUMLEY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

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III.	Columbia's Pipeline Replacement Efforts	9
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I. Introduction

Q. Please state your name and business address.

A. My name is Raymond A. Brumley. My business address is 121 Champion Way, Suite 100, Canonsburg, Pennsylvania 15317.

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

A. I am employed by Columbia Gas of Pennsylvania, Inc. (“Columbia” or the “Company”) as the Director of Construction.

Q. Please briefly describe your professional experience.

A. I began my career in 1992 with Columbia and have held numerous operational positions with increasing responsibilities. From March of 2000 through June of 2002, I was responsible for scheduling work for Columbia Gas of Virginia, Inc. I moved into a Field Engineering role in June of 2002, where I designed capital work for the Company and Columbia Gas of Maryland, Inc. until March of 2011. I then became a leader within the construction department for Columbia, and from there took on roles of increased responsibilities as a Senior Operations Support Specialist and Leader Operations Support Specialist. In June 2016, I accepted the role of Contractor Performance Manager for the seven states within NiSource. I returned to Pennsylvania and Maryland in November of 2019 as the Manager, Construction Services and began my current role of Director of Construction on January 1, 2021.

Q. Please describe your educational background.

1 A. I completed coursework at California University of PA towards a Bachelor's Degree
2 in Business Administration. I received numerous certificates and training
3 opportunities throughout my career.

4 **Q. What are your responsibilities in your current position?**

5 A. My responsibilities include:

- 6 • Directing construction operations in executing the delivery of safe, reliable,
7 efficient natural gas distribution service to our customers;
- 8 • Assuring construction is in compliance with Federal, State and local
9 regulations as well as in alignment with industry best practices;
- 10 • Sponsoring the implementation and execution of capital construction
11 initiatives that build consistency, collaboration, and efficiency across
12 organizations; and
- 13 • Building and maintaining a network of contract resources that have the
14 capacity and capability to execute on Columbia's capital program.

15 **Q. Have you previously testified before this or any other regulatory agency?**

16 A. Yes. I have testified before the Pennsylvania Public Utility Commission
17 ("Commission") in each of the Company's base rate cases since 2021. I have also
18 testified before the Maryland Public Service Commission in support of Columbia Gas
19 of Maryland base rate cases and infrastructure tracker filings.

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

1 A. I will provide testimony in support of Columbia's plant additions through the Fully
2 Projected Future Test Year ("FPFTY") (twelve-months ending December 31, 2026)
3 and provide an overview of Columbia's ongoing replacement activities.

4 **II. Columbia's Projected Plant Additions through the FPFTY**

5 **Q. Please explain Columbia's capital plant additions related to**
6 **distribution plant claimed for the Future Test Year and Fully Projected**
7 **Future Test Year.**

8 A. Columbia plans to maintain or increase its capital expenditures related to
9 distribution plant in the 2024 through 2028 timeframe, with a planned spending
10 program of over \$300 million budgeted annually for replacement work, inclusive
11 of mains, services, and measurement and regulation stations, over the 5-year
12 period. This budget includes the following capital budget classes: Age and
13 Condition, Betterment, and Public Improvement.

14 A detailed description of Columbia's Age and Condition actuals for 2024, and
15 the budgeted amount for 2025 and 2026 are provided in the following table.
16

Table 1

Budget Class - Age and Condition

Description	Total 2024 Actual	Total 2025 Projected	Total 2026 Projected
Measuring and Regulating Station	423	0	0
Compressor Stations	0	430,000	447,200
Mains - Leakage Elimination	270,229,835	195,526,400	227,180,800
Service Lines – Replaced	53,295,151	44,999,000	51,412,200
Customer Service Lines Replaced	12,962,666	15,000,000	17,137,400
Meters / 998 Int. Co. Meters	1,351,592	1,229,500	1,291,800
Meter Install – Replace	1,085,424	1,216,000	1,277,600
House Regulators - Replace	478,332	94,700	99,500
Plant Regulators – Replace - PODs	15,428,926	18,125,800	9,933,400
Reg Structures Replace	659,819	686,000	724,600
LV Excess Press Meas Sta	205,150	951,700	999,900
Corrosion Mitigation Ins	142,023	158,600	166,600
Service Regulators - Replacement	8,395	20,900	22,000
In-Line Inspection	3,438,858	27,800,000	24,300,000
Meter Move Out Program	5,365,563	6,344,400	8,545,800
	364,652,157	312,583,000	343,538,800

The table below (Table 2) depicts the three budget classes, Age and Condition, Betterment, and Public Improvement (rounded to the thousands). The differences in Age and Condition shown between the two tables are the Shared Service expenditures shared among all NiSource companies. Those Shared Service expenditures are not included in Table 1 above.

Table 2

CPA Budget Class	2024 Actuals	2025 Approved	2026 Projected
Age and Condition	364,672,000	312,706,000	343,668,000
Betterment	18,343,000	14,224,000	27,241,000
Public Improvement	1,640,000	14,969,000	9,988,000

1 **Q. Please provide some insight into Table 1 above.**

2 A. Within our 2025 Age & Condition budget, Columbia is still projecting increases in
3 unit cost expenditures for mainline and service line replacement work, primarily due
4 to increased contractor pricing. Also, unit costs per foot for mainline replacements
5 and unit costs for service line replacements in recent years have included additional
6 usage of flaggers and staging vehicles on job sites to address increased work zone
7 intrusions, which is a significant safety threat to our employees, our contractors, and
8 the everyday work that we do. This safety initiative for additional flaggers and staging
9 vehicles at job sites is helping to minimize this growing threat to allow our workforce
10 to concentrate on their tasks at hand and set-up and tear down in a safe and efficient
11 manner. Section IV of my testimony, “Replacement Costs & Restoration Issues”,
12 provides further details on causes that continue to be significant drivers to the overall
13 unit cost increase as well. With that stated, although Table 1 shows a very slight
14 decline in overall estimated expenditures in mainline and respective service line
15 replacements, Table 1 also shows estimated increases in Plant Regulator (aka District
16 Stations) / Point of Delivery (“POD”) Replacements as well as In Line Inspections
17 (“ILI”). Both are significant parts of Columbia’s Safety Management System (“SMS”).
18 Company witness Scutta (Columbia Statement No. 14) provides more information
19 regarding SMS.

20 Table 3 below provides estimates for work to be done to prepare for
21 Columbia’s ILI on our CAT Line in Emigsville and D-10132 at State College during
22 2025 and 2026.

Table 3

-Line Inspection Project Name	Length (miles)	HCA (miles)	Diameter (in)	Original Install (year)	MAOP (PSIG)	2024 Actual Expenditures (in millions)	2025 Estimated Expenditures (in millions)	2026 Estimated Expenditures (in millions)
CAT - Emigsville	6.2	2.6	12	1958	550	3.00	23.20	3.00
D-10132 - State College	10.6	1.7	8 & 12	1966	400	0.44	4.60	21.30

ILI of transmission pipelines, where viable, is an advanced inspection technique in use across the natural gas industry and is largely successful in susceptibility identification along the entire pipeline. The use of ILI on a transmission pipeline to identify threat conditions allows for proactive mitigation of targeted segments for replacement versus less effective system wide mitigation activities, such as over the ground Cathodic Protection surveys which can only detect external corrosion susceptibilities. Further, ILI detects all forms of metal loss and geometry changes occurring from mechanical damage, manufacturing defects, construction issues, external and internal corrosion and outside forces.

Columbia is focused on advancing ILI as the most effective and complete assessment method to identify threats to transmission pipelines in a proactive manner with the overall vision to prevent failures across those pipelines effectively, efficiently, and completely. The Company has selected two pipeline systems to be retrofitted for ILI. Construction execution is currently planned for 2025 for the CAT Line in Emigsville. In 2026, the smart pig will be run and the data analyzed to determine if any segments are warranted for replacement. For D-10132 at State College, the goal is to complete design engineering, land acquisitions, and the purchase of long lead time materials in 2025, with construction execution planned

1 for 2026. In 2027, the smart pig will be run and the data analyzed to determine if any
2 segments are warranted for replacement.

3 **Q. Are there costs for any new initiatives for which the Company is seeking**
4 **recovery?**

5 A. Yes, the Company will be planning to install Advanced Metering Infrastructure
6 (“AMI”) devices. Approximately 330,000 Automated Meter Reading (“AMR”) devices
7 are expected to reach end of life (“EOL”) over the next decade, with most
8 devices reaching EOL between 2029 and 2032. These AMR devices must be replaced;
9 the current manufacturer, Itron, has stated that the production capacity of AMR
10 meters currently used by Columbia is being phased out, making it unlikely that these
11 devices will be available in quantities sufficient to meet current or future Columbia
12 needs. Currently, as a result of supplier limitations, the Company is purchasing AMI
13 meters that are being utilized in AMR mode (AMI meters can be used in both AMR
14 and AMI function) to sustain drive-by meter readings until AMI technology can be
15 fully implemented on Columbia’s system. The chart below compares the capabilities
16 of AMR technology with that of AMI technology.

	CURRENT STATE	FUTURE STATE
Functionality	Automated Meter Reading (AMR)	Advanced Metering Infrastructure (AMI)
Meter Reading	•Leverages “drive-by” process with reading device in Columbia vehicle	•Meter read data transmitted over AMI comms network (cellular or point-to-multipoint)
Communications	•One-way communication between meter and reading device	•Two-way communications between meter and utility systems
Read Rate	•Reads collected monthly without interval reads; utility and customers are only able to view usage for full bill periods	•Interval reads collected and sent more frequently to utility: hourly reads sent every four hours •Utility and customers able to view daily and hourly usage
Alerts and Alarms	•Potential for some basic exception alerts and alarms	•Revenue recovery – theft and tamper alarms •Operational and safety – Auto shutoff for high-flow, etc.
Shut Off	•Must physically show up to customer premise and complete manually	Remotely shutoff meters (Gas) or utilize the configurable autonomous closure function
Outage Management	•Customers must call in outages	•AMI outage and meter status integrated into Columbia outage management system •Less time spent identifying and dispatching crews, overall faster outage restoration
Advanced Future Capabilities	•N/A	•Dynamic and advanced customer bill programs •Automatic and remote shutoff (gas – ultrasonic meters)

Q. What are the benefits of AMI?

A. Please see the bullets listed below for some of the strategic benefits of AMI:

Improved Reliability & Safety

- Faster Outage Identification (Integrated Gas Meters)
- Meter Status Monitoring
- Tamper Detection
- Unsafe Condition Sensing (High-Flow/Pressure/Temp)

- Reduced On-site Visits

Enhanced Customer Experience

- Customer Usage Display
- Informed CSRs (On-Demand Reads, Meter Status, etc.)
- Reduced On-site Visits
- Increased usage granularity (multiple daily reads)

Operational Efficiencies & Societal Benefits

- Automated and Remote Meter Reading
- Reduced Vehicle emissions
- Establishes Datasets to support potential future advanced forecasting and system modeling/planning efforts

Q. When might Columbia start to use this new technology?

A. The Company plans to begin installing AMI devices in 2026. Replacement of the aging AMR devices to AMI devices will continue in future years.

III. Columbia's Pipeline Replacement Efforts

Q. How many feet of bare steel, wrought iron, and cast iron main have been eliminated from Columbia's system during its accelerated program, and how does that trend compare with the previous years?

A. Columbia began an accelerated replacement of bare steel, wrought iron, and cast iron pipe in 2007. Between 2007 and the end of 2024, Columbia retired the following footages of bare steel, wrought iron, and cast iron by year:

1	2007	355,764	feet
	2008	528,567	feet
	2009	344,488	feet
2	2010	322,583	feet
	2011	553,765	feet
	2012	415,240	feet
3	2013	452,636	feet
	2014	413,667	feet
	2015	496,610	feet
4	2016	478,790	feet
	2017	509,428	feet
	2018	302,606	feet
5	2019	516,689	feet
	2020	387,821	feet
	2021	440,036	feet
6	2022	433,930	feet
	2023	482,076	feet
	2024	436,830	feet
7	Total Actual (Through YE 2024)		<u>7,871,526</u> feet
8			

9 From 2007 through 2024, Columbia's replacement program eliminated an average
10 of 437,307 feet of pipe per year. By contrast, during the four (4) years from 2002 to
11 2005, Columbia's average annual rate of retirement was 196,948 feet, less than half
12 the rate of retired footages of bare steel, wrought iron, and cast iron under the current
13 program. Underscoring the success of Columbia's efforts, as of the end of December
14 2022, Columbia no longer has any known cast iron main left in its distribution
15 system.

16 **Q. Why does Columbia need to continue to replace its bare steel systems?**

17 A. Columbia's Distribution Integrity Management Program ("DIMP") risk scoring
18 continues to rank external corrosion on bare steel among our top system risks.
19 Corrosion on first generation mains represents approximately 60% of all hazardous
20 or potentially hazardous leakage cleared on mains in the Columbia distribution

1 system as of year ending 2023. The Company believes that the accelerated
2 replacement of the first-generation facilities on its system is not only prudent but is
3 a requirement under Federal DIMP requirements that Columbia continues to
4 address very aggressively in a consistent and programmatic way.

5 **Q. Is there another solution for addressing the issues with bare steel, short**
6 **of replacement?**

7 A. No. Corrosion leakage on unprotected steel does not slow down and the rate of
8 leakage will only accelerate as the unprotected steel facilities continue to deteriorate.
9 First generation unprotected steel pipe, some of it dating to the turn of the last
10 century, has reached or soon will reach the end of its useful life and must be replaced
11 in a timely, cost-effective manner.

12 **Q. Do safe and reliable system operations requirements demand**
13 **replacement of Columbia's unprotected steel facilities?**

14 A. Yes. If left unchecked, continual system degradation due to unrelenting corrosion
15 will challenge Columbia's ability to meet peak day needs and operate the system
16 safely. Therefore, continuing Columbia's main replacement program is essential to
17 minimize leakage and the associated public risks and additional strain on the system
18 when required to meet peak day demands.

19 **Q. Are you saying Columbia's system is unsafe?**

20 A. No, I am saying the system is safe right now, as evidenced and described in Columbia
21 witness Scutta's testimony (Columbia Statement No. 14) by our ability to address
22 Type-1 and Type-2 leaks appropriately, as well as all the other operational

1 improvements, better emergency leak response, and a continued focus to reduce the
2 backlog of open Type-2 leaks. Columbia's system is comprised of thousands of miles
3 of wrought iron, bare steel, cathodically-protected steel, and plastic pipe. The
4 material initially at risk is generally first-generation bare steel and wrought iron.
5 Evidence further indicates that the corrosion with respect to unprotected coated steel
6 (also referred to as "pre-71 coated steel") is accelerating, gradually causing more
7 leaks. Wrought iron is a hybrid of cast iron and bare steel that demonstrates very
8 similar corrosion characteristics to that of bare steel. Additionally, "first generation"
9 pre-1982 plastic pipe has demonstrated itself to be prone to stress propagation
10 cracking under some circumstances due to the different composition of the base
11 plastic material.

12 While the system is currently safe, Columbia must, as a prudent operator,
13 address the systemic problem of replacing its remaining bare steel, wrought iron, pre-
14 1982 plastic and pre-1971 ineffectively coated steel pipeline facilities as explained in
15 Columbia's most recently approved Long Term Infrastructure and Improvement
16 Plan LTIIP at Docket P-2022-3037388. Witness Scutta provides further testimony
17 with respect to replacement of unprotected coated steel and first-generation plastic
18 pipe.

19 **Q. Will Columbia's accelerated replacement program provide customers**
20 **with any other benefits besides the replacement of bare steel, wrought**
21 **iron, pre-82 plastic and pre-71 coated steel with plastic and cathodically**
22 **protected steel?**

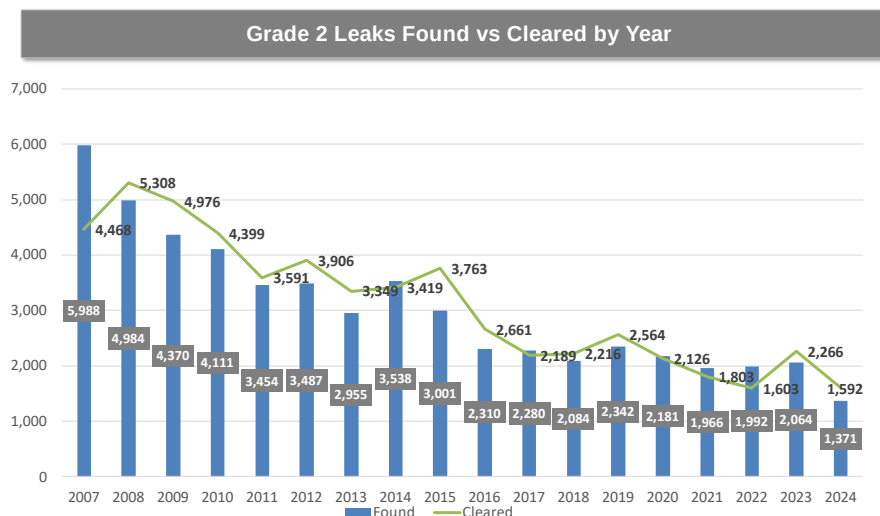
1 A. Yes. Columbia is replacing the segmented, 19th and early 20th century low-pressure
2 designs of its first-generation system with a more integrated, 21st century system
3 design. This integrated, higher-pressure system (up to a maximum of 99 pounds
4 operating pressure, though we will typically operate at 60 pounds per square inch
5 gauge (“PSIG”) or lower) will enable Columbia to substantially reduce the current
6 need for district pressure regulator stations throughout its system, resulting in a
7 safer, easier, and more reliable system to operate. Instead, each residence will have
8 a small domestic-sized regulator installed just upstream of the meter to reduce the
9 pressure before it enters the house. Also, a distribution system operating at these
10 higher pressures will enable Columbia to install new safety devices in areas to be
11 upgraded. As part of the upgrade, Columbia is installing excess flow valves (“EFVs”)
12 on nearly all services connected to the replaced mains.¹ The EFVs will shut off gas to
13 a residence or business in the event of a large pressure differential that is indicative
14 of a major gas leak or a service damaged by excavation. Over time, this results in a
15 system where services are much less vulnerable to safety risks from third-party
16 damage.

¹ An exception may be granted to installing an EFV on multifamily residences and non-residential (e.g. commercial, industrial) service types by a Field Engineering Manager when the known customer load at the time of installation is 1,000 cubic feet per hour (“CFH”) or greater. If an exception is granted, a curb valve shall be installed in accordance with the applicable Columbia Gas Standard (GS 3020.020 “Service Lines Valves Requirements and Locations”) and also documented on the service line record as to why an EFV was not installed. Note EFVs are currently available up to 10,000 CFH capacity. This means that for the majority of new and replaced service lines on systems with an MAOP greater than 10 psig, the service line will have an EFV installed.

Q. How will main replacements affect the Company's leak repair experience?

A. The long-term view is that as bare steel and wrought iron are removed from the system, we expect to see a continued reduction in Type 1 and Type 2 leakage repair necessitated by corrosion. However, this impact is expected to continue to be gradual over the period of the program. The remaining wrought iron and bare steel pipe to be replaced continues to degrade, which continues to drive Type 1 and Type 2 leakage repair activities. Entering 2025, as a result of Columbia's aggressive pipe replacements, together with Columbia's aggressive leak repair program, Columbia had a total number of 440 Type-2 outstanding leaks in its system. As shown in the figure below, there is a noticeable downward trajectory of type 2 leaks found on the distribution system since the beginning of Columbia's accelerated pipeline replacement program in 2007.

Safety and Reliability



1 **Q. How does the public benefit from Columbia’s ongoing replacement of its**
2 **aging facilities?**

3 A. Columbia is removing deteriorating portions of its system and enhancing the safety
4 of its system by ensuring replacement of facilities with new, durable and safer
5 materials. Its system will continue to be able to provide deliverability at its maximum
6 allowable operating pressure (“MAOP”), thus the public will receive better service,
7 with fewer interruptions. Customers currently experience the benefits of the
8 investments being made to enhance the safe and reliable delivery of their natural gas
9 service. During the “Polar Vortex” events of both 2014 and 2015, Columbia’s
10 distribution system performed well and experienced no significant issues with service
11 interruptions or curtailments of firm customers. The same has held true through the
12 other cold weather events of the 2017-2018 winter heating season, as well as this past
13 2024-2025 winter heating season. Further, Columbia’s comprehensive system
14 replacement program is adding jobs throughout Columbia’s service territory, both in
15 the ranks of full-time Columbia employees (these include engineers and engineering
16 technicians, land agents, and construction coordinators and construction
17 specialists), as well as the contractors who perform the actual pipe replacement
18 (which includes laborers, equipment operators, crew leaders, and support staff) and
19 associated support services such as: paving, traffic control, trucking, sand and gravel,
20 and a myriad of other material purchases and support activities that are needed to
21 execute this type of strategic replacement program. Finally, to emphasize the
22 magnitude of this program, on average during 2024, Columbia had approximately

1 92 crews, which employed approximately 920 contractor employees and
2 subcontractors (e.g. restoration, flaggers, drillers, plumbers, etc.). For 2025,
3 Columbia will have approximately 85 crews with approximately 850 contractor
4 employees and subcontractors (e.g. restoration, flaggers, drillers, plumbers, etc.).
5 For 2026, contracted resources utilized by Columbia would be comparable to that of
6 2025.

7 **Q. Is there anything else that you would like to say about Columbia's**
8 **pipeline replacement efforts?**

9 A. Yes. Taken in total, Columbia has made enormous progress since 2006 in delivering
10 and maintaining a safe and reliable distribution system for its customers. The
11 progress that I refer to is defined in more detail throughout Columbia witness
12 Scutta's testimony, but includes identification and mitigation of system cross bores,
13 reducing the number of inactive services in the system, improving the locating
14 process to reduce third-party damage, improving emergency response rates and on-
15 time appointments for customers, and dramatically increasing the amount of bare
16 steel and first generation plastic pipe that it removes from the system annually
17 compared to pre-2007 levels. However, the system data is clear that Columbia will
18 have to continue to focus on the accelerated replacement of first-generation bare
19 steel, pre-71 coated steel, and first generation plastic to address the problems
20 associated with aging infrastructure. Therefore, it is essential that Columbia continue
21 to direct management effort and incremental capital resources toward this ongoing
22 need. The synchronization of these replacement efforts with the enhanced focus on

1 pipeline safety that Columbia has demonstrated over the last 18 years are integral
2 parts of Columbia's DIMP Plan and are essential planks of Columbia's ongoing effort
3 to enhance natural gas pipeline integrity management and, thus, provide a safe,
4 reliable distribution system for our customers and the general public.

5 **IV. Replacement Costs & Restoration Issues**

6 **Q. How have replacement costs trended and what are the primary cost**
7 **drivers?**

8 A. Columbia has experienced upward cost pressure for replacement projects over the
9 past several years. The average cost of main replacement when Columbia began its
10 accelerated main replacement program was \$81.25 per foot, while the average cost
11 of main replacement in 2024 was \$335 per foot (this unit cost is inclusive of all sizes
12 and types, steel and plastic, replacements within Columbia's Age & Condition,
13 Betterment, and Public Improvement Budgets). The following factors create the
14 upward cost pressure:

- 15 • The location of projects has a significant impact on cost. Hard surface projects
16 in urban areas normally have a higher replacement cost per foot than soft
17 surface replacement in rural areas, given that similar size and material of pipe
18 are being installed. The increased cost of urban areas can be due in part to the
19 need to coordinate replacement of Columbia's facilities with facilities of other
20 utilities or municipalities. These higher cost urban areas often experience
21 higher risk and are increasingly being prioritized for replacement,
22 contributing to the increasing average cost per foot.

- Changes in hard surface restoration requirements are a key component of the upward cost pressures. Municipalities are expanding restoration requirements on utilities. For example, fifteen years ago it was typical that trench restoration would consist of simply paving the trench that was excavated for the main installation. Today, that same project frequently requires curb to curb milling and overlay. On other projects, Columbia is required to locate its facilities under sidewalks. On these projects, Columbia is required to replace the entire sidewalk, and to the extent that the sidewalk does not meet Americans with Disabilities Act (“ADA”) standards, Columbia is required to make them compliant with current ADA standards. This means that Columbia may need to install wheelchair ramps and curb realignment or replacement work.
- Contractor cost is another key component of increased costs. Contractor cost increases are driven by competition for resources as more natural gas distribution companies in Pennsylvania and across the country undertake main replacement programs, increase training and qualification requirements, and compete for the availability of construction work with other businesses inside and outside of the industry.

Q. What is Columbia doing to manage cost increases?

A. Columbia is focused on managing costs and making prudent capital investments that benefit our customers. As one of six gas distribution companies within the NiSource family making infrastructure capital investments, we are able to negotiate at scale

1 with contractors and suppliers, delivering competitive pricing for materials and
2 services provided to Columbia.

3 Further, Columbia has initiated significant efforts regarding the management
4 of permitting and restoration costs, which I will describe later in my testimony.
5 Columbia's service territory spans over 450 municipalities in the Commonwealth of
6 Pennsylvania, each of whom are authorized to set their own municipal ordinances
7 related to street openings. Columbia incurs restoration costs on pipeline
8 replacement projects in compliance with the ordinance of the municipality in which
9 the pipeline is replaced.

10 Since November of 2020, we have added nine Construction Project
11 Management positions across the state to provide more project management rigor to
12 our larger, more complex projects. The responsibilities of these positions include,
13 but are not limited to, assisting in the project design, permitting process, job
14 readiness, maintaining job scope, costs, safety, productivity, and constant
15 communication with internal and external stakeholders. They maintain a working
16 relationship with municipal leaders during the job while delivering job updates.

17 **Q. Do municipal standards continue to impact Columbia's aggressive**
18 **pipeline replacement program?**

19 A. Yes. Columbia serves approximately 446,000 customers within 26 counties and
20 roughly 450 municipalities throughout the Commonwealth. Because of the size of
21 our footprint, the number of municipalities we operate in and the lack of standard
22 ordinances and restoration requirements across those communities, as a Company,

1 we continue to face challenges related to local municipal oversight, fees, permitting
2 processes and project restoration requirements related to our pipeline replacement
3 program. Local municipalities struggling with budgetary issues continue to look to
4 shift costs and road maintenance responsibilities to utilities working (cutting into
5 their streets) in their communities. Increased local municipal requirements or fees
6 have and will continue to delay our pipeline replacement work and new business
7 efforts, as well as cost the Company and our customers additional money.

8 **Q. What is Columbia's plan to address these ongoing municipal challenges?**

9 A. Columbia continues to implement a comprehensive plan to address municipal issues.
10 The Company's Public Affairs team (in addition to select local operations,
11 construction, engineering and new business employees) developed and executed a
12 proactive municipal outreach program to establish, improve and maintain
13 relationships with municipal officials in communities where we are, and will be,
14 conducting significant pipeline replacement or new business projects. The program
15 continues to focus on educating identified local staff/officials and elected
16 representatives of boroughs, townships and cities/towns about:

- 17 o Columbia;
- 18 o Our pipeline replacement and new business efforts in general;
- 19 o Specific planned pipeline replacement or new business projects in their
20 community;
- 21 o The benefits of our pipeline replacement or new business projects in their
22 community; and

1 o The need for reasonable permit fees and restoration requirements.

2 The Public Affairs team works directly with municipalities to review proposed or
3 passed local public policies that may impact Columbia's proposed work. Specifically,
4 the Public Affairs team is tasked with monitoring municipal ordinances and
5 proposed amendments that may unreasonably increase paving restoration
6 requirements, unreasonably increase permitting fees or place additional
7 unreasonable fees for inspections, road openings or road degradation on Columbia's
8 work.

9 The Company's Government Affairs team also educates State Representatives and
10 State Senators in our service territory about the ongoing cost increases municipal
11 governments are charging utility ratepayers through increased permitting and
12 engineering fees as well as restoration requirements for Columbia's work in their
13 municipalities. As a result, HB 1655 was introduced on September 5, 2023, which if
14 it had been adopted, would have prohibited local municipal governments from
15 implementing permit fees and restoration standards that exceed Pennsylvania
16 Department of Transportation permit fees and restoration standards. On September
17 6, 2023, Columbia testified in strong support of HB 1655 at a House Consumer
18 Protection, Technology & Utilities Committee hearing on the legislation. While the
19 legislation did not pass during the 2023-24 legislative session, Columbia will
20 advocate reintroduction and passage of the legislation during the 2025-26 legislative
21 session.

22 **Q. Please provide further detail on the outreach focus of the municipal**

outreach program.

A. The outreach program focuses on, but is not limited to, the following groups:

- Local boroughs, townships and cities/towns in which we have not replaced significant mainline pipe or had new business projects but have planned upcoming projects.
- Local boroughs, townships and cities/towns in which we need to improve and enhance relationships due to past issues or new ordinances adversely affecting our operations or our customers.
- The district offices and staff of identified state legislators to educate them on planned pipeline replacement/new business projects in their districts and to gain a better understanding about local governments and their leadership. These offices may also be able to assist Columbia with relationship building and communications with local governments when appropriate.

Q. Do you have some examples of how Columbia was proactively engaged in addressing municipal issues in the most recent calendar year, 2024?

A. Yes. In 2024, the Public Affairs team participated in the following proactive outreach discussions:

- **Adams County** – Columbia conducted proactive outreach to New Oxford Borough on a pipeline replacement project.
- **Allegheny County - City of Pittsburgh Utility Coordination:** Throughout the year, Columbia participated with the City of Pittsburgh in its utility coordination meetings to coordinate utility projects between the City

1 and utilities working in the right of way, as well as road restoration and
2 repaving efforts.

- 3 • **Allegheny County** – Columbia conducted proactive outreach with Bethel
4 Park Borough, Castle Shannon Borough, Coraopolis Borough, Dormont
5 Borough, Greentree Borough, Mount Lebanon Township, City of
6 Pittsburgh, Pleasant Hills Borough, Scott Township, South Fayette
7 Township, and Whitehall Borough regarding pipeline replacement projects
8 or operational work in those communities.

- 9 • **Beaver County** – Columbia conducted proactive outreach with Ambridge
10 Borough, Beaver Borough, Center Township, and Economy Borough on
11 pipeline replacement projects and other work.

- 12 • **Butler County** – Columbia conducted a proactive meeting with Cranberry
13 Township on emergent work.

- 14 • **Centre County** – Columbia conducted proactive outreach with Bellefonte
15 Borough regarding a pipeline replacement project.

- 16 • **Fayette County** – Columbia conducted proactive outreach with Dunbar
17 Township, Newell Borough, Redstone Township, South Union Township
18 and the City of Uniontown on pipeline replacement projects.

- 19 • **Lawrence County** – Columbia conducted proactive outreach with
20 Ellwood City Borough and the City of New Castle on meter move out work
21 and pipeline replacement projects.

- 22 • **Somerset County** – Columbia conducted proactive outreach to Berlin

Borough on a pipeline replacement project.

- **Washington County** – Columbia conducted proactive outreach with Canonsburg Borough, Cecil Township, Charleroi Borough, Donora Borough, and Elco Borough, North Franklin Township, North Strabane Township, South Franklin Township, South Strabane Township, West Bethlehem Township and the City of Washington on pipeline replacement projects.

- **York County** – Columbia conducted proactive outreach to Hopewell Township, East Manchester Township, Manchester Township, Mount Wolf Borough, Spring Garden Township, Springettsbury Township, and West Manchester Township on pipeline replacement projects.

Q. When a municipality requests restoration beyond the area in which Columbia's pipeline replacement activity occurs, what does Columbia do to resolve the issue?

A. When the Company encounters a situation in which a municipality requests atypical or non-PennDOT standard restoration requirements, Columbia tries to negotiate a compromise with the municipality. This approach helps Columbia maintain good rapport with townships and municipalities. Maintaining relationships with municipalities and townships is very important, especially in the unforeseen event of an emergency. Thus, negotiation is the initial starting point and preferred resolution method.

Further, while negotiation is the preferred method for resolution, sometimes

1 a compromise cannot be reached. When a compromise cannot be reached, the
2 Company further analyzes the situation to determine the best path to move forward.
3 The Company can opt to pursue litigation or evaluate whether to move forward with
4 the project. Whether or not to move forward with a project is evaluated on an
5 individual project basis, as each situation presents unique circumstances.

6 **Q. Outside of the examples provided above, has Columbia been successful**
7 **in challenging restoration requirements that Columbia considers to be**
8 **atypical?**

9 A. Yes. Some examples of Columbia's success are as follows:

- 10 • **City of Pittsburgh, Allegheny County:** In November and December of
11 2023, Columbia raised concerns to members of Pittsburgh City Council
12 regarding a City of Pittsburgh Department of Mobility and Infrastructure
13 proposal to create a new \$110 per service line fee on top of right-of-way
14 opening fees on utility pipeline replacement projects in the city. The new fee
15 was part of the 2024 proposed city budget and needed to be approved by
16 Pittsburgh City Council. As a result of Columbia's education and advocacy
17 against the proposal, the fee was reduced to \$30 per service line and saved
18 ratepayers an estimated \$30,000 in fees in 2024.

- 19 • **Canonsburg Borough, Washington County:** Columbia has engaged
20 the borough since 2020 regarding a permit fee and road restoration ordinance
21 put into effect in 2020 that significantly increases costs for Columbia's work.
22 The ordinance requires curb to curb paving plus 25 feet on each side of a road

1 cut and increased small project permit fees up to \$950 per project. It also
2 created a linear and square foot fee for larger projects resulting in permit fees
3 for two pipeline replacement projects costing more than \$12,000 and \$13,000
4 for each project.

5 The paving restoration costs for the two pipeline replacement
6 projects using the curb to curb plus 25 feet paving standard in the borough's
7 ordinance were significant. If Columbia restored to PennDOT standards,
8 the cost was approximately \$260,000. If Columbia restored to the
9 borough's curb to curb plus 25 feet standard, the restoration cost increased
10 to approximately \$470,000 – an additional cost to ratepayers of \$210,000.

11 In the Summer of 2023, Columbia refused to pave to the curb to curb
12 plus 25 feet standard and threatened litigation against the borough.
13 Columbia negotiated a PennDOT-like paving restoration plan with the
14 borough saving ratepayers additional costs. Columbia continues to work
15 with the borough council regarding permit fee costs and restoration
16 standards related to Columbia's work.

- 17 • **Charleroi Borough, Washington County:** The borough has an
18 ordinance requiring curb to curb paving if more than ten percent of the
19 square area of any 50-foot length of roadway is opened and a permit fee
20 formula of \$8 per linear foot up to 100 feet; plus \$2 per linear foot after that.
21 Columbia negotiated a 50 cents per linear foot fee and PennDOT restoration
22 standards for 2024 pipeline replacement project work.

- 1 • **Dunbar Township, Fayette County:** The township's permit fee
2 formula is a \$250 application fee plus \$5 per square foot of opening.
3 Columbia had three proposed pipeline replacement projects in the township
4 for 2024 and 2025. The estimated permit fees for the three proposed
5 projects under the ordinance was approximately \$262,000. The estimated
6 PennDOT permit fee for identical projects in their right-of-way is \$4,892.
7 Columbia worked with the township's solicitor and council on a more
8 reasonable permit fee for the three projects of \$1 per linear foot resulting in
9 a permit fee for the three projects of approximately \$12,500.
- 10 • **East Manchester Township, York County:** In 2024, Columbia sought
11 permits to undertake pipeline replacement projects in the township for 2024 and
12 2025. As part of accepting the permit, the Company was provided an "Appendix
13 document" that stated the restoration requirements would be "curb to curb plus
14 ten feet on each side of any cut" with a permit fee of \$2.40 per linear foot.
15 Columbia met with township officials and expressed concerns with the restoration
16 requirements and permit fee costs. Working with the Supervisors and solicitor,
17 Columbia negotiated PennDOT restoration standards for our projects and the
18 Supervisors passed an ordinance reducing the permit fee from \$2.40 per linear
19 foot to \$1.00 per linear foot for our projects.
- 20 • **Menallen Township, Fayette County:** In January of 2022, Columbia was
21 planning two proposed pipeline replacement projects and had been
22 approached by a potential new customer to provide service to their home in
23 Menallen Township. Columbia's engineering department analyzed the

1 township's fee ordinances to conduct work in the right-of-way on the
2 proposed projects. The township's ordinance contains a permit fee formula
3 of a \$150 application fee; an inspection and supervision fee for the township
4 engineer of \$75 per hour with a minimum of four hours or a \$300 fee; and
5 a \$3.67 per square foot fee for an opening or excavation.

6 Columbia engineers estimated the township's fees for the proposed
7 projects would be approximately \$48,105 and exceeded fees charged by the
8 PennDOT for similar work in its right-of-way by more than \$45,000.

9 After months of negotiations that did not produce results, on October
10 26, 2022, Columbia filed a complaint in the Commonwealth Court of
11 Pennsylvania challenging certain provisions of Menallen Township's
12 ordinance regarding permitting fees and right-of-way fees as excessive. The
13 case is currently pending in Commonwealth Court.

- 14 • **Redstone Township, Fayette County:** The township has a permit fee
15 formula of \$150 application fee, plus \$75 per hour with four-hour minimum
16 engineering inspection and supervision fee, plus \$36.70 per square foot
17 permit fee. Columbia has engaged the township's council regarding
18 pipeline replacement projects in 2025 and 2026 that would replace
19 approximately 9,600 linear feet of pipe. Those projects had estimated
20 permit fees of more than \$700,000. Columbia worked with the township's
21 Supervisors to resolve the issues through a paving restoration cooperative
22 arrangement where the township took responsibility for final mill and

1 paving of the roads disturbed by our project and Columbia reimbursed the
2 township our estimated costs for restoration. As part of the agreement, the
3 township waived all permit fee costs.

- 4 • **West Brownsville Borough, Washington County:** Since the Spring of
5 2021, Columbia has engaged in discussions with the borough's council
6 regarding the Company's concerns with the borough's road restoration
7 ordinance, Ordinance No. 2019-347. The restoration requirements of the
8 ordinance demand paving for any opening no less than ten (10) feet in each
9 direction from either edge of original excavation for the entire street width.
10 (curb to curb/edge to edge)

11 Columbia restored operational project work areas in the borough to
12 PennDOT restoration standards outlined in 67 PA Code Section 459.8 and
13 PennDOT Publication 408. For those work projects, the total disturbed
14 area is approximately 730 square feet. The cumulative required restoration
15 under Ordinance 2019-347 is 5,970 square feet.

16 If comparing restoration costs for the Columbia work projects, the
17 cost of restoration of the locations to PennDOT standards was
18 approximately \$4,522. Restoration in accordance with the Ordinance
19 would increase costs to ratepayers by approximately \$32,236. The
20 borough's code enforcement officer, solicitor and council members
21 threatened citations against Columbia for violations of Ordinance 2019-
22 347. Discussions continued in the Fall of 2023 and were not

1 productive. The borough's ordinance also has a permit fee formula for
2 larger projects that is \$10 per linear foot resulting in a \$43,000 permit fee
3 plus the potential payment of engineering costs for a proposed 2025
4 pipeline replacement project.

5 On July 15, 2024, Columbia filed a complaint in the Commonwealth
6 Court of Pennsylvania challenging certain provisions of West Brownsville
7 Borough's ordinance regarding permitting fees and restoration standards as
8 excessive. The case is currently pending in Commonwealth Court.

9 **Q. Does this conclude your Direct Testimony?**

10 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	Docket No. R-2025-3053499
v.	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	

**DIRECT TESTIMONY OF
VINCENT V. REA**

ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

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ACRONYMS AND DEFINED TERMS

<u>ACRONYM</u>	<u>DEFINED TERM</u>
β	Beta
CAPM	Capital Asset Pricing Model
CPA	Columbia Gas of Pennsylvania, Inc.
DCF	Discounted Cash Flow Model
EBITDA	Earnings before interest, taxes, depreciation and amortization
FFO	Funds from Operations
FOMC	Federal Open Markets Committee
g	Growth Rate (perpetual)
GDP	Gross Domestic Product
M&M	Modigliani and Miller
PUHCA	Public Utility Holding Company Act of 2005
QE	Quantitative Easing
QT	Quantitative Tightening
R_f	Risk-Free Rate of Return
R_m	Expected return for the overall stock market
ROE	Return on Equity
RPM	Risk Premium Method

ACRONYMS AND DEFINED TERMS

<u>ACRONYM</u>	<u>DEFINED TERM</u>
S&P	Standard & Poor's
SURFA	Society of Utility and Regulatory Financial Analysts
WACC	Weighted average cost of capital

I. INTRODUCTION

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

A. My name is Vincent V. Rea. I currently serve as Managing Director of Regulatory Finance Associates, LLC, an independent financial and regulatory consulting firm. My business address is 80 Blake Boulevard, #4572, Pinehurst, NC 28374.

Q. Please describe your professional experience.

A. Prior to moving into my current position, I served as Director, Regulatory Finance and Economics for NiSource Corporate Services Company. In this position, I provided expert testimony and other regulatory support on behalf of NiSource Inc.'s ("NiSource") utility subsidiaries with regard to the cost of equity, overall fair rate of return, and ratemaking capital structures. Prior to serving as Director, Regulatory Finance and Economics, I served as Assistant Treasurer for Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"), and its ultimate parent company, NiSource. In the capacity of Assistant Treasurer, I was responsible for the external capital-raising activities and banking activities for NiSource, for inter-company financing activities among all NiSource subsidiaries (including Columbia), and also provided regulatory support and testimony for utility rate proceedings and financing petitions. My educational background, professional experience and other qualifications are presented in greater detail in Exhibit VVR-1, which follows my Direct Testimony.

Q. Please describe your educational background.

A. I hold an M.B.A. in Finance from Indiana University, Bloomington, Indiana, and a B.A. with honors distinction in Business Administration from Lake Forest College,

Lake Forest, Illinois.

Q. Do you hold any professional designations?

A. Yes. I have been awarded the designation of Certified Rate of Return Analyst (“CRRA”) by the Society of Utility and Regulatory Financial Analysts (“SURFA”), and I am also a registered Certified Public Accountant (“CPA”) in the State of Illinois.

Q. Are you a member of any industry or professional organizations?

A. Yes, I am a member of SURFA.

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

A. My Direct Testimony presents supporting evidence, analysis and a recommendation concerning the appropriate rate of return on common equity and overall rate of return that the Pennsylvania Public Utility Commission (the “Commission”) should establish for Columbia in relation to its revenue requirement calculation. My recommendations are supported by the detailed financial information and comprehensive analyses presented within my testimony.

Q. Are you sponsoring any exhibits through your Direct Testimony?

A. Yes. The table below lists the exhibits that I am sponsoring through my testimony, and includes a brief description of each exhibit.

Exhibit	Description
Exhibit VVR-1	Professional Qualifications of Vincent V. Rea
Exhibit VVR-2	Comparative Risk Assessment
Exhibit VVR-3	Analysis of Regulatory Mechanisms
Exhibit VVR-4	W.A.C.C. and Fair Rate of Return
Exhibit VVR-5	Capitalization and Capital Structure Ratios
Exhibit VVR-6	Cost of Long-Term and Short-Term Debt
Exhibit VVR-7	DCF Method - Gas LDC Group
Exhibit VVR-8	DCF Method - Combination Utility Group

Exhibit VVR-9	DCF Method - Non-Regulated Group
Exhibit VVR-10	Book vs. Market Value Capital Structures
Exhibit VVR-11	Capital Asset Pricing Model
Exhibit VVR-12	Risk Premium Method

1 **Q. Have there been any changes in the labeling of the exhibits relating to**
2 **the cost of capital evaluation in this proceeding as compared to**
3 **Columbia's 2024 rate case filing in Docket No. R-2024-3046519?**

4 A. Yes. In the Company's previous rate proceedings, witness Paul R. Moul included
5 all of his cost of capital and capital structure related exhibits in Company Exhibit
6 No. 400. However, due to the differences in our respective approaches to
7 conducting our cost of capital evaluations, I have only included the information
8 contained in Exhibit VVR-4, Exhibit VVR-5 and Exhibit VVR-6, as referenced
9 above, in Company Exhibit No. 400.

10 **II. SUMMARY OF RECOMMENDATIONS**

11 **Q. Based upon your comprehensive analyses and supporting evidence,**
12 **what have you concluded with respect to the appropriate rate of return**
13 **for Columbia in this proceeding?**

14 A. Based upon my comprehensive evaluation, I have concluded that Columbia's cost
15 of common equity is currently in the range of 10.85 - 11.35 percent. In view of the
16 range estimate yielded by my comprehensive evaluation, it is my opinion that a
17 reasonable point estimate of Columbia's cost of equity in the current market
18 environment is 11.10 percent, which reflects the significant increase in long-term
19 capital costs that has occurred over the past few years. In recognition of the
20 Company's management effectiveness as further discussed below, my overall cost

1 of equity recommendation in the instant proceeding is 11.35 percent, which
2 includes a 0.25 percent upward adjustment for management performance.
3 Although I have not conducted an independent evaluation of the Company's
4 management effectiveness, Company witness Nicole M. Paloney, Director of Rates
5 and Regulatory Affairs for Columbia, describes the superior performance of its
6 management in her Direct Testimony (Columbia Statement No. 9). Witness
7 Paloney demonstrates in her Direct Testimony that the Company and its
8 employees continue to perform at a high level to the benefit of its customers and
9 the communities that the Company serves. In this regard, witness Paloney
10 discusses Columbia's strong performance in the following areas:

- 11 • Columbia's Commitment to Low Income Customers;
- 12 • Performance results from the Utility Consumer Activities Report
13 and Evaluation (UCARE) and Quality of Service Reports;
- 14 • Process Improvements Enhancing Customer Service;
- 15 • Improvements made for Customer, Employee and System Safety;
- 16 • Serving Our Communities; and,
- 17 • Management Audit Performance

18
19 Based upon the above findings, and as reflected in Exhibit VVR-4, I have also
20 determined that the Company's weighted average cost of capital is 8.55 percent,
21 which is based upon Columbia's rate-setting capital structure and embedded cost
22 of debt as reflected within Exhibits VVR-5 and VVR-6, respectively. This resulting
23 overall cost of capital, if adopted by the Commission, will allow Columbia to earn
24

1 the prevailing opportunity cost of capital, maintain its financial integrity, and
2 attract capital at reasonable terms.

3 **Q. What general approach have you taken in determining the cost of**
4 **common equity in this proceeding?**

5 A. To properly estimate Columbia's cost of equity, I have analyzed market-derived
6 data and other financial information for each of the companies comprising three
7 separate proxy groups. Considering that investors utilize this very same
8 information in assessing risk and making investment decisions, it provides a
9 reliable basis for estimating the cost of equity for Columbia. In total, I evaluated
10 the market and financial data of 25 companies, including six companies
11 comprising the Gas LDC Group, ten companies comprising the Combination
12 Utility Group, and nine companies comprising the Non-Regulated Group. I will
13 discuss the selection criteria I utilized in developing each of these proxy groups
14 later in my testimony.

15 During the course of my evaluation, I applied three well-recognized
16 analytical models to the market and/or financial data of the selected proxy group
17 companies. These models include the Discounted Cash Flow ("DCF") model, the
18 Capital Asset Pricing Model ("CAPM"), and the Risk Premium Method ("RPM"). I
19 have also evaluated two other model variants of the CAPM, specifically, the CAPM
20 with size adjustment, and the Empirical CAPM ("ECAPM"), both of which have
21 been validated by empirical research. Using the multi-faceted analytical approach
22 described above, my evaluation resulted in 15 individual estimates of the cost of
23 equity for Columbia, thereby ensuring a thorough and comprehensive analysis.

1 **Q. Specifically, how did you complete your cost of equity analyses using**
2 **the market-derived data and other financial information for the three**
3 **respective proxy groups?**

4 A. With respect to the DCF analyses, I evaluated the proxy group companies on an
5 individual basis, which resulted in a separate cost of equity estimate for each
6 company. By taking this approach, I was able to identify anomalous or “outlier”
7 results at the individual company level which did not pass fundamental tests of
8 economic logic. I then eliminated these outlier results from further consideration
9 based upon both “high-end” and “low-end” outlier thresholds as established by
10 regulatory precedent. The fundamental advantage of employing this approach is
11 that it completely removes the effects of anomalous results from the cost of equity
12 evaluation process. In my judgment, this approach is clearly preferable to the
13 “total group approach,” which simply averages the data of all proxy group
14 companies, irrespective of whether outlier results are included or not. As such, the
15 total group approach effectively “blends in” the effects of anomalous results into
16 the cost of equity evaluation process.

17 Notwithstanding the foregoing, with respect to the CAPM and RPM
18 analyses, the respective proxy groups were evaluated on a group average basis
19 rather than on an individual company basis. This is necessary because virtually all
20 of the input variables into these two analytical models are non-company specific
21 variables (i.e. risk-free rate of return, corporate bond yields for a certain credit
22 rating, market rate of return, etc.), with the sole exception of beta, meaning that

1 under these two approaches, company-specific input anomalies will have less of an
2 impact on the cost of equity estimate as compared to the other analytical methods.

3 **Q. What are the results of your cost of equity evaluation for the proxy**
4 **sources, and how did you derive the cost of equity for Columbia using**
5 **these proxy group results?**

6 A. I developed my cost of equity recommendation after carefully evaluating 15
7 individual cost-of-equity estimates, which were derived from applying the various
8 analytical models to the market and financial data of the proxy group companies.
9 Using a variety of analytical models in conjunction with multiple comparable-risk
10 proxy groups ensures that a diversity of investor perspectives is incorporated into
11 my evaluation and provides a solid foundation upon which the analyst can apply
12 his/her informed judgment in making a cost of equity recommendation. Initially,
13 cost of equity estimates were derived for the respective proxy groups by applying a
14 total of five different analytical models/methods to the market and/or financial
15 data of the proxy group companies (my evaluation included two additional variants
16 of the traditional CAPM model). This resulted in a total of 15 individual estimates
17 of the cost of equity among the three proxy groups, as summarized in Table VVR-
18 1 below. Further support for these 15 individual estimates of the cost of equity can
19 be found in Table VVR-7, Table VVR-8, Table VVR-9, Table VVR-11 and Table
20 VVR-12, which appear later in my testimony.

Table VVR-1 Indicated Cost of Equity for the Proxy Groups			
Method/Model	Gas LDC Group	Comb. Utility Group	Non- Reg. Group
DCF	10.97%	10.57%	11.27%
Traditional CAPM	11.05%	11.12%	11.05%
CAPM (w/size adj.)	11.66%	11.58%	10.99%
ECAPM	11.21%	11.26%	11.21%
Risk Premium	11.23%	11.23%	11.38%

As reflected in Table VVR-2 and Table VVR-3 below, an analysis of the above results shown in Table VVR-1 yield the following measures of central tendency for each of the analytical methods employed.

Table VVR-2 Cost of Equity Estimates for CPA Measures of Central Tendency for the Core Proxy Group – Gas LDC Group	
Median DCF Result	10.97%
Average DCF Result	10.97%
Median CAPM Result	11.21%
Average CAPM Result	11.31%
Median RPM Result	11.23%
Average RPM Result	11.23%

Table VVR-3 Cost of Equity Estimates for CPA Measures of Central Tendency for All Three Proxy Groups	
Median DCF Result	10.97%
Average DCF Result	10.94%
Median CAPM Result	11.21%
Average CAPM Result	11.24%
Median RPM Result	11.23%
Average RPM Result	11.28%

Based upon these measures of central tendency, I have concluded that Columbia's cost of equity is presently in the range of 10.85 - 11.35 percent, and that point estimate in the middle of this range, or 11.10 percent, fairly reflects the Company's cost of equity in the current market environment. In making this determination, I relied predominately on my quantitative results for the Gas LDC Group, as shown in Table VVR-2 above, which constitutes my core proxy group in this proceeding. At the same time, the composite results for all three of the proxy groups that I

1 evaluated, as shown in Table VVR-3 above, produces estimates of the cost of equity
2 that are very similar to the results for the Gas LDC Group on a standalone basis.
3 These results further validate the benefits of evaluating complementary proxy
4 groups in corroborating the results produced for the Gas LDC Group.

5 Additionally, as noted earlier, the Company has proposed a 0.25 percent upward
6 adjustment to my point estimate of the cost of equity in recognition of the
7 Company's strong record of management effectiveness as discussed in the Direct
8 Testimony of Columbia witness Paloney. After incorporating this proposed
9 adjustment, it is my recommendation that the Commission should adopt a cost of
10 equity of 11.35 percent in the determination of a fair rate of return for the Company
11 in this proceeding.

12 **III. OVERVIEW OF U.S. CAPITAL MARKET TRENDS AND FEDERAL**
13 **RESERVE BOARD ACTIONS**

14 **Q. Please provide an overview of recent trends in the U.S. capital markets**
15 **and the Federal Reserve Board's monetary policy actions, particularly**
16 **as it impacts the Company's long-term capital costs for purposes of this**
17 **proceeding.**

18 A. It is clear that long-term capital costs have increased significantly in recent years.
19 This is perhaps best demonstrated by the fact that the trading yields for the 10-year
20 U.S. Treasury note and 30-year Treasury bond climbed to their recent historical
21 high levels during the first ten months of calendar-year 2023 (through October
22 2023). The 10-year Treasury yield rose to 4.98 percent during late October 2023,
23 its highest level in more than 16 years (since July 2007), while the 30-year Treasury

1 yield rose to 5.11 percent during mid-October 2023, its highest level in more than
2 17 years (since July 2006). However, between October 2023 and September 2024,
3 the 10-year and 30-year Treasury yields generally followed a downward trajectory
4 as compared to the highs recorded during October 2023, as the U.S. inflation rate
5 also continued to trend downward from the 40-year high levels recorded during
6 the summer of 2022.

7 Nevertheless, since October 2024, longer-term interest rates have once again
8 begun to trend upward, which many market observers have attributed to a higher
9 level of uncertainty in the U.S. capital markets surrounding the potential effects of
10 fiscal and other governmental policy changes which are expected to be
11 implemented by the Trump Administration. For the most part, these concerns
12 center upon the potential inflationary impacts of various policy initiatives that
13 President Trump committed to implementing on the campaign trail, including
14 increased tariffs on U.S. trading partners, federal income tax policy changes which
15 could potentially have the effect of increasing the federal deficit, as well as a
16 number of immigration reforms. As a result, long-term interest rates have
17 generally trended upward since October 2024. This strongly suggests that other
18 long-term capital costs, including Columbia's cost of equity, have also risen
19 materially in recent months.

20 **Q. What monetary policy actions has the Fed taken in recent months?**

21 A. In recent months, the Fed has elected to reduce the Federal Funds target rate by a
22 cumulative amount of 1.00 percent (100 basis points), or from 5.25-5.50 percent
23 to 4.25-4.50 percent. The Fed implemented these rate reductions in three steps,

1 which included a 50 basis point reduction announced after the central bank's
2 September 17-18, 2024 FOMC meeting, an additional 25 basis point reduction
3 announced after the Fed's November 6-7, 2024 FOMC meeting, and another
4 additional 25 basis point reduction announced after the Fed's December 17-18,
5 2024 FOMC meeting. Furthermore, in the Fed's press release after the December
6 17-18, 2024 FOMC meeting, the central bank also indicated that it would continue
7 reducing its holdings of U.S. Treasury and mortgage-backed securities by allowing
8 \$60 billion of these securities holdings to mature each month without further
9 reinvestment of the proceeds. More specifically, the Fed stated the following in its
10 press release after the December 17-18, 2024 FOMC meeting:

11 Recent indicators suggest that economic activity has continued to
12 expand at a solid pace. Since earlier in the year, labor market
13 conditions have generally eased, and the unemployment rate has
14 moved up but remains low. Inflation has made progress toward the
15 Committee's 2 percent objective but remains somewhat elevated.

16 The Committee seeks to achieve maximum employment and
17 inflation at the rate of 2 percent over the longer run. The Committee
18 judges that the risks to achieving its employment and inflation goals
19 are roughly in balance. The economic outlook is uncertain, and the
20 Committee is attentive to the risks to both sides of its dual mandate.

21 In support of its goals, the Committee decided to lower the target
22 range for the federal funds rate by 1/4 percentage point to 4-1/4 to
23 4-1/2 percent. In considering the extent and timing of additional
24 adjustments to the target range for the federal funds rate, the
25 Committee will carefully assess incoming data, the evolving outlook,
26 and the balance of risks. The Committee will continue reducing its
27 holdings of Treasury securities and agency debt and agency
28 mortgage-backed securities. The Committee is strongly committed

1 to supporting maximum employment and returning inflation to its 2
2 percent objective.¹

3 It is noteworthy that in each of the Fed's post-FOMC meeting statements since
4 March 2022, the Fed has reiterated its commitment to reduce the size of its balance
5 sheet, which the Fed has gradually pared down to the current level of \$6.6 trillion,
6 which includes U.S. Treasury and mortgage-backed securities holdings. As the Fed
7 continues to liquidate its security holdings going forward, the downward pressure
8 that the Fed's quantitative easing programs were originally designed to exert on
9 long-term interest rates will gradually be removed. In other words, considering
10 that the Fed's Quantitative Easing programs have had the effect of *reducing*
11 intermediate and long-term interest rates, the Fed's current policy objective of
12 Quantitative Tightening is widely expected to have the opposite effect by putting
13 *upward* pressure on interest rates going forward, which is consistent with the
14 marked increase in long-term U.S. interest rates over the past several years.

15 **Q. What actions did the Fed take during its January 28-29, 2025 FOMC**
16 **meeting?**

17 A. During the January 28-29, 2025 FOMC meeting, the Fed did not take any further
18 actions with regard to the Federal Funds target rate, citing the fact that the U.S.
19 inflation rate remains somewhat elevated. As such, the Fed Funds target rate
20 currently remains at 4.25 percent to 4.50 percent.

¹ *Federal Reserve Issues FOMC Statement* (December 18, 2024), at 1. Available
at: <https://www.federalreserve.gov/newsevents/pressreleases/monetary20241218a.htm>

1 **IV. FUNDAMENTAL ANALYSIS**

2 **A. Background**

3 **Q. What background information have you considered in evaluating**
4 **Columbia's cost of common equity and overall required rate of return?**

5 A. Columbia provides natural gas services to more than 446,000 residential,
6 commercial, and industrial customers in 26 counties throughout Pennsylvania's
7 greater York, State College and Western Pennsylvania service territories. During
8 2024, the Company's total gas throughput was divided among the following
9 customer classes: 39.5 percent residential; 29.5 percent commercial; and 31.0
10 percent industrial and transportation customers. Columbia sources its natural gas
11 supplies from various producers and marketers and has delivery arrangements
12 with various interstate pipeline companies.

13 The Company is a wholly-owned subsidiary of NiSource Gas Distribution
14 Group, Inc., which, in turn, is a subsidiary of NiSource Inc., a holding company
15 under the Public Utility Holding Company Act of 2005. NiSource's headquarters
16 are located in Merrillville, Indiana, and its core operating companies engage in
17 natural gas distribution, as well as electric generation, transmission and
18 distribution. NiSource operating companies deliver energy to nearly 4.0 million
19 gas and electric customers in six states.

20 **Q. Does Columbia face any unique risks that differentiate it from other**
21 **gas distribution utilities?**

22 A. Yes. Columbia faces certain unique risks that have a bearing on the Company's
23 cost of equity. First, in the Western region of Pennsylvania, Columbia operates

1 within overlapping service territories which exposes the Company to market
2 competition from other local gas utilities, thereby increasing its risk profile.
3 Second, there are six interstate pipelines that pass through Columbia's service
4 territory, which increases the risk of bypass for the Company's large volume
5 customers. And third, the presence of local gas production also creates a bypass
6 threat for the Company, and particularly with respect to production originating
7 from the Marcellus Shale formation. For these reasons, the Company faces
8 competitive risks that are considerably greater than the typical gas distribution
9 utility, and this includes the companies comprising the Gas LDC Group, which
10 provided the underlying basis for developing my cost of equity estimates in this
11 proceeding.

12 **Q. Is Columbia's risk profile impacted by the Company's throughput to**
13 **large volume customers and customers with other competitive**
14 **alternatives?**

15 A. Yes. Columbia's risk profile is impacted by the Company's significant amount of
16 its gas throughput to large industrial and commercial customers and customers
17 with competitive alternatives. In particular, this is demonstrated by the threat of
18 bypass posed to 53 of the Company's major account customers, as throughput to
19 these 53 customers constitutes approximately 23 percent (17,200,281 Dth
20 /74,772,633 Dth) of the Company's total gas throughput. At the same time, it is
21 highly likely that this value constitutes just a subset of the total load at risk, since
22 the Company has not identified all customers who have competitive alternatives
23 available to them.

1
2 In essence, there are four primary threats to throughput for the Company's largest
3 volume customers. First, the Company can and has experienced attrition in this
4 large customer group. Second, as noted earlier, Columbia's largest customers,
5 which have traditionally used transportation service, have the ability to bypass the
6 Company's system to other gas supply sources such as interstate pipelines, other
7 local gas utilities, and non-regulated pipeline contractors providing access to local
8 supplies. Third, in addition to bypass threat, the Company also faces the potential
9 threat that its gas throughput to large customers may be exposed to alternative
10 energy sources such as electricity, which is particularly the case in view of recent
11 trends toward decarbonization and electrification. Lastly, Columbia is vulnerable
12 to the impact of the business cycle on its large volume customers and competition
13 in the industries served by its customers, as well as other external factors that can
14 result in shifts of production to customer facilities that are outside of the
15 Company's service territory.

16 **Q. Have you considered the degree to which Columbia's required**
17 **infrastructure investments affect the Company's risk profile?**

18 A. Yes. In order to maintain safe and reliable service to its customers, Columbia must
19 make significant investments to maintain and upgrade its gas distribution
20 infrastructure. The Company's system upgrades require capital expenditures that
21 most often do not result in an increase to its customer base. The Company has
22 made significant progress in reducing its percentage of unprotected steel pipe,
23 however, these facilities still account for 785 miles (or approximately 10.1 percent)

1 of its distribution mains as of year-end 2024. In addition, the Company has also
2 recently been focused on necessary investments with respect to replacing first
3 generation plastic pipe. Columbia also has 30,746 (or approximately 6.9 percent)
4 of its services constructed of unprotected steel. Therefore, the Company fully
5 anticipates that it will continue to make significant infrastructure investments over
6 the foreseeable future.

7 **Q. In determining an appropriate authorized ROE for Columbia in this**
8 **proceeding, should the Commission consider the unique risks facing**
9 **the Company as to the competitive environment in which it operates,**
10 **and the significant amount of capital expenditures that the Company**
11 **will need to make in support of its infrastructure replacement**
12 **requirements?**

13 A. Yes, in determining an appropriate cost of equity for the Company, the
14 Commission should give consideration to the competitive environment in which
15 Columbia operates, as well as the Company's ongoing requirements to replace its
16 distribution infrastructure. A fair rate of return that appropriately recognizes
17 these unique risks will better support Columbia's financial profile, which will
18 enable the Company to attract the necessary capital to fund its capital expenditure
19 program on reasonable terms. The Company has been proactive in dealing with
20 its capital requirements for infrastructure investments by not making any dividend
21 payments in any of the years between 2014 and 2024. By foregoing dividend
22 payments, the Company has shown a commitment to reinvestment in

Pennsylvania. The Commission should recognize and reward this commitment with a reasonable return on equity.

B. Comparative Risk Assessment of Columbia vs. the Proxy Groups

Q. Why is it necessary to analyze groups of proxy companies to estimate the cost of equity for Columbia?

A. The cost of equity is an opportunity cost concept, which is determined in the financial markets based upon the relative risk assessments of investors. Simply stated, in order to attract sufficient capital to support their public service obligations, regulated utilities must offer investors a rate of return that is commensurate with returns available on alternative investments bearing similar risks. For this reason, the use of proxy groups is useful in estimating a utility's cost of equity. Regardless of whether the subject utility is publicly-traded or not, proxy group analyses ensure that fair rate of return principles, including comparable earnings, corresponding risks, and the opportunity cost of capital are all considered when estimating a utility's cost of equity.² Nonetheless, it should be noted that when the various cost of equity models are applied to the market and financial data of proxy group companies, various model inputs and/or assumptions are required, which contributes to the risk of observation error. For

² These fair rate of return principles were articulated by the U.S. Supreme Court in various landmark case decisions, including *Willcox et. al., Constituting the Public Service Commission of New York v. Consolidated Gas Co.*, 212 U.S. 19 (1909); *Bluefield Water Works and Improvement Company v. Public Service Commission of the State of West Virginia*, 262 U.S. 679 (1923); and *Federal Power Commission et al. v. Hope Natural Gas Company*, 320 U.S. 591 (1944). Although the *Hope* and *Bluefield* cases are widely-referenced with regard to fair rate of return standards, the *Consolidated Gas* case was actually the first case where the Supreme Court addressed principles surrounding a fair rate of return for public utility companies.

1 this reason, when possible, the use of larger proxy groups or even multiple proxy
2 groups is recommended to mitigate these effects and to ensure a higher level of
3 confidence in the reliability of the analytical results.

4 **Q. What criteria did you apply in selecting the companies included in your**
5 **gas utility proxy group?**

6 A. In selecting a gas utility proxy group, my objective was to identify a group of
7 publicly-traded natural gas distribution companies with risk characteristics
8 similar to Columbia, which is not a publicly-traded company. Accordingly, I
9 applied the following selection criteria in making this determination: (i) Value
10 Line Investment Survey Industry Classification as a Natural Gas Utility; (ii) Value
11 Line Safety Rank of “1,” “2” or “3”; (iii) S&P corporate credit rating no lower than
12 BBB-, or Moody’s long-term issuer rating of no lower than Baa3; (iv) operating
13 income from the company’s regulated gas distribution operations equals or
14 exceeds 60 percent of the company’s consolidated operating income; (v) company
15 must currently pay dividends and must not have discontinued or reduced its
16 dividend during the previous five years (2019-2023); and (vi) company is not, and
17 has not recently been, an acquisition target. Applying the above selection criteria
18 yielded a core proxy group that is comprised of the following six publicly-traded
19 natural gas distribution companies:

20 Atmos Energy Corp.

21 NiSource Inc.

22 Northwest Natural Gas Co.

23 ONE Gas, Inc.

24 Southwest Gas Holdings, Inc.

1 Spire, Inc.

2 Throughout the remainder of my testimony, I will refer to this proxy group as the
3 “Gas LDC Group.”

4 **Q. Why is it necessary to complete a comparative risk assessment between**
5 **Columbia and the Gas LDC Group?**

6 A. Considering that market-derived information for the Gas LDC Group companies
7 will be used to estimate Columbia’s cost of equity, it is critical that the Gas LDC
8 Group is risk-comparable to the Company. If material differences in risk are
9 identified, the analyst must apply his/her informed judgment in determining
10 whether further adjustments are required to the cost of equity estimates indicated
11 by application of the various analytical models. Because Columbia is not publicly-
12 traded, market-based financial information is not available for the Company.
13 Therefore, in conducting my comparative risk assessment, I have instead analyzed
14 various widely-recognized business and financial risk metrics, none of which are
15 dependent upon stock prices or other market-based information.

16 **Q. Do a utility’s credit ratings provide insight into its risk profile, cost of**
17 **debt and cost of equity?**

18 A. Yes. Credit ratings reflect the risk of default with respect to a company’s debt
19 obligations and are, therefore, strongly correlated with a company’s borrowing
20 costs. For example, companies with a lower risk of default are assigned higher
21 credit ratings and therefore benefit from lower borrowing costs. Conversely,
22 companies with a high risk of default are assigned lower credit ratings and
23 consequently incur higher borrowing costs. A firm with higher borrowing costs

1 will also have a higher cost of equity, since investors invariably demand an equity
2 risk premium above and beyond the firm's cost of debt as compensation for bearing
3 the additional risks inherent in common stocks. Although the credit rating
4 agencies do not currently issue ratings for Columbia, the Company's ultimate
5 parent company, NiSource, has been assigned long-term credit ratings of BBB+ by
6 Standard and Poor's and Baa2 by Moody's.

7 Presently, S&P has assigned an average corporate credit rating of "BBB+"
8 for the companies comprising the Gas LDC Group, while Moody's has assigned an
9 average long-term issuer rating of "Baa1" for the Gas LDC Group companies. Both
10 the S&P and Moody's ratings reflect the overall credit worthiness of the issuing
11 company, rather than the risk of default for a specific debt issue. Additional
12 information on the Gas LDC Group's average credit ratings can be found on page
13 7 of Exhibit VVR-7.

14 **Q. When evaluating Columbia versus the Gas LDC Group, how do their**
15 **business and financial risk metrics compare?**

16 A. The results of my comparative risk assessment for Columbia and the Gas LDC
17 Group are presented on pages 1 and 2 of Exhibit VVR-2, respectively. Pages 3 and
18 4 of Exhibit VVR-2 provide additional information on the capitalization ratios for
19 each of the six companies comprising the Gas LDC Group. Within this exhibit, I
20 have evaluated the five-year historical period of 2019-2023, along with the five-
21 year historical averages. My findings are summarized by individual risk metric as
22 presented below:

1. Relative Size

Based on a total book capitalization of \$3.0 billion, Columbia is approximately 1/4th the size of the average company within the Gas LDC Group (\$11.1 billion). It is well-documented in the finance literature that small capitalization companies have a higher risk profile as compared to large capitalization companies, and therefore earn higher relative returns. This is known as the “size effect” and is often attributed to the greater relative impact that significant (negative) events can have on smaller firms, vis-à-vis larger firms. Morin summarizes the size effect in *Modern Regulatory Finance*, a widely referenced authoritative guide on utility cost of capital matters, as follows:

Investment risk increases as company size diminishes, all else remaining constant. Small companies have very different returns than large ones, and on average they have been higher.

...

In addition to earning the highest average rates of return, small stocks also have the highest volatility, as measured by the standard deviation of returns.

....

Size is a significant factor that increases both business risk and financial risk and, therefore, the cost of capital.³

Furthermore, in multiple academic papers, distinguished researchers Fama and French identified company size as a significant factor in explaining equity returns. As a result of their research, Fama and French developed an enhanced CAPM, known as the “Three Factor Model,” which recognized that the “size premium” is

³ Roger A. Morin, *Modern Regulatory Finance* (PUR Books LLC, 2021), at 213, 217 and 218.

1 an essential component in estimating the cost of equity for small capitalization
2 firms⁴.

3 2. Volatility of Return on Book Equity

4 In the absence of observable market data, both the standard deviation and
5 coefficient of variation of a time series of annual book ROEs can serve as suitable
6 risk measurement substitutes for beta. Although standard deviation is a measure
7 of total risk, while beta is a measure of non-diversifiable systematic risk, these two
8 risk measures have been shown to be correlated. The coefficient of variation is
9 calculated as the ratio of the standard deviation of ROE to the mean ROE, which
10 facilitates a comparison of the degree of variation from one data series to another
11 (i.e., Columbia vs. Gas LDC Group), even if the respective mean ROEs differ
12 significantly. Higher calculated values for the standard deviation and coefficient
13 of variation indicate greater volatility in achieved ROEs, which corresponds to a
14 higher overall level of investment risk. For the period 2019-2023, the standard
15 deviation of achieved ROEs was 1.18 percent for Columbia, and 0.89 percent for
16 the Gas LDC Group. For the same period, the coefficient of variation was 0.122 for
17 Columbia and 0.106 for the Gas LDC Group, reflecting a marginally higher relative
18 volatility in achieved ROEs for Columbia.

19 3. Equity Capitalization Ratio

20

⁴ See Eugene F. Fama and Kenneth R. French, "Industry Costs of Equity," *Journal of Financial Economics*, 43 (1997): 153-193; and Eugene F. Fama and Kenneth R. French, "The Capital Asset Pricing Model: Theory and Evidence," *The Journal of Economic Perspectives*, 18 (Summer 2004), at 25-46.

1 All else being equal, a company with a higher equity capitalization weighting
2 has a lower level of financial risk, while a company with a lower equity
3 capitalization weighting has a higher level of financial risk. This is because
4 companies which rely more heavily on debt capital to finance their operations are
5 subject to a higher level of contractual obligations in the form of periodic principal
6 and interest payments. Increasing levels of fixed-payment obligations constrain a
7 company's financial flexibility, especially during economic downturns, and
8 therefore increase a company's financial risk profile. For this reason, the debt-to-
9 capitalization ratio, which is the complement of the equity capitalization ratio,
10 serves as an important financial metric that is routinely used by the rating agencies
11 to assess a company's credit quality and overall financial risk profile. The 5-year
12 average equity capitalization ratio for Columbia is 56.0 percent based upon
13 permanent capitalization, and 52.6 percent based upon total capitalization. The 5-
14 year average equity capitalization ratio for the Gas LDC Group *holding companies*
15 is 48.7 percent based upon permanent capitalization, and 43.4 percent based upon
16 total capitalization. As outlined in Exhibit VVR-5, the Company has proposed a
17 54.4 percent common equity ratio for rate-setting purposes in the instant
18 proceeding, which reflects the Company's fully projected future test year
19 ("FPFTY") capital structure as of December 31, 2026, which, consistent with
20 Commission precedent, includes short-term debt.

21 4. EBITDA-to-Interest Coverage

22 The EBITDA-to-Interest Coverage ratio is a key analytical metric routinely
23 used by the rating agencies to evaluate whether a company's earnings and cash

1 flow are sufficient to adequately cover its debt service obligations. Higher coverage
2 ratios generally imply lower levels of financial risk and higher credit quality. The
3 5-year average EBITDA-to-Interest Coverage ratio for the years 2019-2023 is
4 6.23x for Columbia and 6.96x for the Gas LDC Group.

5 5. FFO-to-Adjusted Total Debt

6 The FFO-to-Adjusted Debt ratio is another important analytical metric used
7 by the rating agencies and expresses a company's annual operating cash flows as a
8 percentage of its total adjusted debt. The reciprocal of the FFO-to-Adjusted Debt
9 ratio provides an approximate estimate of the total number of years of annual cash
10 flows that would be required to retire a company's adjusted debt obligations. The
11 5-year average FFO-to-Adjusted Total Debt ratios for the years 2019-2023 is 18.9
12 percent for Columbia and 14.9 percent for the Gas LDC Group.

13 **Q. What other factors have you considered in conducting your**
14 **comparative risk assessment between Columbia and the Gas LDC**
15 **Group?**

16 A. I have also considered the degree to which the Company employs various forms of
17 regulatory mechanisms as compared to the Gas LDC Group companies. As
18 discussed in the Direct Testimony of Columbia witness John D. Taylor (Columbia
19 Statement No. 17), the Company is requesting that the Commission approve the
20 Company's current pilot WNA mechanism as a permanent program. Furthermore,
21 as discussed in Mr. Taylor's testimony, the Company is also proposing the
22 implementation of a RNA mechanism for non-CAP residential and C&I customers,

1 which would address the various drivers of revenue variation other than weather.
2 Lastly, the Company has also proposed an increase to its fixed customer charge for
3 both its residential and non-residential customers. In essence, the adoption of
4 these proposed regulatory mechanisms would put the Company on a more equal
5 footing with the Gas LDC Group companies. This is demonstrated in Exhibit VVR-
6 3, which illustrates that the majority of the companies included in the Gas LDC
7 Group already employ various forms of rate designs and regulatory mechanisms
8 which serve to reduce revenue variability and/or cost recovery lag. As shown in
9 Exhibit VVR-3, the regulatory mechanisms employed by the Gas LDC Group
10 companies include weather normalization adjustments (“WNA”), revenue
11 normalization adjustments (“RNA”), straight-fixed-variable rate designs and
12 infrastructure cost recovery mechanisms.

13 Considering that the majority of the Gas LDC Group companies already utilize the
14 same types of regulatory mechanisms that Columbia has proposed in this
15 proceeding, any theoretical risk reduction and associated reduction in the cost of
16 equity resulting from these mechanisms would already be reflected in the market
17 prices of the Gas LDC Group companies. In other words, since investors are
18 already aware of the mechanisms employed by the Gas LDC Group companies,
19 they have already incorporated these mechanisms into their risk perceptions and
20 rate of return expectations. As noted earlier, the adoption of Columbia’s proposed
21 regulatory mechanisms would put the Company on a more equal footing with the
22 Gas LDC Group companies. However, to the extent that the Company’s proposals
23 regarding the WNA, RNA and increase to the fixed customer charge are not

1 adopted, the Company's risk profile will be relatively higher than the Gas LDC
2 Group, which serves as the underlying basis for estimating Columbia's cost of
3 equity. Under these circumstances, the Gas LDC Group's estimated cost of equity
4 will understate the market required return for Columbia.

5 **Q. What conclusions have you drawn from your comparative risk**
6 **assessment between Columbia and the Gas LDC Group?**

7 A. The *business risk* metrics I evaluated suggest that the Company has a somewhat
8 higher business risk profile as compared to the Gas LDC Group, as demonstrated
9 by the Company's: (1) relatively higher exposure to market competition in its
10 service territory; (2) high level of capital expenditure requirements in support of
11 its infrastructure replacement initiatives; (3) significantly smaller size compared
12 to the average company in the Gas LDC Group; (4) marginally higher variability of
13 book returns on equity, as measured by both the standard deviation and the
14 coefficient of variation; and (5) current limited utilization of revenue stabilization
15 mechanisms relative to the Gas LDC Group companies.

16 At the same time, the *financial risk* metrics that I evaluated yielded mixed results,
17 but generally suggest that Columbia has a slightly lower financial risk profile as
18 compared to the Gas LDC Group. Therefore, on an *overall basis*, I have concluded
19 that the totality of Columbia's investment risk metrics indicate that the Company
20 has a similar overall investment risk profile as compared to the Gas LDC Group.

21 **Q. Have you considered any other proxy groups in estimating the cost of**
22 **equity for Columbia?**

23 A. Yes, I have. As previously stated, the use of multiple comparable-risk proxy groups

1 ensures a higher level of confidence in the reliability of the analytical results when
2 estimating a utility's cost of equity. The importance of evaluating complementary
3 proxy groups has become particularly evident in recent years, as recent merger and
4 acquisition activity in the regulated utility space has reduced the number of gas
5 utility holding companies to select from in deriving a gas utility proxy group.
6 Therefore, to ensure a robust sample size that will obviate any potential distortions
7 caused by observation errors in the various financial model inputs, I have also
8 evaluated a proxy group of ten combination gas and electric utility companies, and
9 a proxy group of nine non-rate-regulated companies (i.e., the Combination Utility
10 Group and the Non-Regulated Group, respectively). Both of these proxy groups
11 have risk profiles which are similar to the Gas LDC Group. Considering that
12 Columbia is not publicly-traded, the analysis of comparative risk metrics discussed
13 earlier was necessary to establish the relative risk relationship between the
14 Company and the Gas LDC Group. In order to facilitate a comparison of the risk
15 profiles of the Combination Utility Group and the Non-Regulated Group to
16 Columbia, this was accomplished indirectly through a comparative risk assessment
17 of the three proxy groups, as based upon published risk indicators. I will discuss
18 the relative risk relationships between the three proxy groups and Columbia later
19 in my testimony.

20 **Q. Why is it appropriate to evaluate a proxy group of combination gas and**
21 **electric utility companies?**

22 A. Considering the relatively small size of the Gas LDC Group, evaluating a proxy
23 group of comparable-risk combination gas and electric utility companies ensures

1 a higher level of confidence in the reliability of the analytical results when
2 estimating the cost of equity for a gas distribution company. This approach is also
3 consistent with the comparable earnings standard established in *Hope* and
4 *Bluefield*, since gas utilities are entitled to earn a rate of return commensurate with
5 returns offered by other companies having “corresponding risks,” including
6 combination gas and electric utility companies.

7 Morin provides additional support for this approach in *Modern Regulatory*
8 *Finance*, where he argues that a proxy group of combination electric and gas
9 utilities is a suitable complement to a proxy group of gas utilities by stating:

10 This procedure is reasonable given that the natural gas distribution
11 business possesses an investment risk profile that is similar in risk
12 to that of investment-grade combination electric and gas utilities.
13 The latter possess economic characteristics similar to those of
14 natural gas distribution utilities as they are both involved in the
15 distribution of energy services products at regulated rates in a
16 cyclical and weather-sensitive market. They both employ a capital-
17 intensive network with similar physical characteristics. They are
18 both subject to rate of return regulation.⁵

19 Accordingly, the Combination Utility Group that I have referenced represents an
20 entirely reasonable and useful complement to the Gas LDC Group.

21 **Q. Can you provide any additional evidence that your proxy group of**
22 **combination gas and electric utility companies possesses a risk profile**
23 **which is comparable to a proxy group of gas-only utilities, and**
24 **therefore represents a suitable complement to your Gas LDC Group in**
25 **estimating Columbia’s cost of equity?**

⁵ Roger A. Morin, *Modern Regulatory Finance* (PUR Books LLC, 2021), at 445.

1 A. Yes. Substantial evidence suggests that to the extent combination gas and electric
2 utilities are riskier than pure-play gas utilities, the risk differential is not
3 significant. This is demonstrated by the average difference in authorized ROEs
4 granted to gas versus electric utilities by state regulatory commissions over the past
5 44 years (1981 to 2024), which have only been about 11 basis points⁶ higher for
6 electric utilities. More recently, during the past 10-year period (2015 to 2024),
7 authorized ROEs for all electric utilities have only been about 2.5 basis points⁷
8 higher than authorized ROEs for gas utilities. If state regulatory commissions
9 nationwide believed that the risk differential between gas and electric utilities was
10 more significant, this would have been demonstrated by a greater disparity in
11 historically authorized ROEs between gas and electric utilities. Moreover,
12 considering that the Combination Utility Group derives an average of one-third (or
13 33.3 percent) of its consolidated revenues from regulated gas distribution
14 operations, it has an even lower risk profile than the typical electric utility.

15 **Q. What criteria did you use to select the companies included in your**
16 **Combination Utility Group?**

17 A. In developing the Combination Utility Group, my objective was to identify a group
18 of publicly-traded combination gas and electric utility companies with risk

⁶ *The Cost of Capital – A Practitioner's Guide*, D. Parcell, Society of Utility and Regulatory Financial Analysts, (2020), quoting Regulatory Research Associates, at 93; and *RRA Regulatory Focus, Major Energy Rate Case Decisions in the U.S. - January-December 2024*, Regulatory Research Associates, S&P Global Market Intelligence, February 4, 2025, at 3 and Data book Table 3 and Table 4.

⁷ *RRA Regulatory Focus, Major Energy Rate Case Decisions in the U.S. - January-December 2024*, Regulatory Research Associates, S&P Global Market Intelligence, February 4, 2025, at 3 and Data book Table 3 and Table 4.

1 characteristics similar to the Gas LDC Group. Accordingly, I applied the following
2 screening criteria in selecting companies for inclusion in the Combination Utility
3 Group: (i) Value Line Investment Survey Industry Classification as an electric
4 utility; (ii) Value Line Safety Rank of “1”, “2” or “3;” (iii) S&P corporate credit rating
5 no lower than “BBB-”, and Moody’s senior secured debt rating no lower than
6 “Baa3”; (iv) company must have been engaged in both the natural gas distribution
7 and electric distribution businesses for at least the past five years; (v) company
8 must *not* currently operate nuclear power generation facilities, be a significant
9 independent power producer, or have major gas transmission and storage
10 operations; (vi) company must currently pay dividends and must not have
11 discontinued or reduced their dividend payments during the previous five years
12 (2019 to 2023); and (vii) company must not have recently been an acquisition
13 target. Applying the above selection criteria yielded a proxy group consisting of
14 the following ten publicly traded combination gas and electric utility companies:

15 Alliant Energy Corp.
16 Avista Corp.
17 Black Hills Corp.
18 CMS Energy Corp.
19 Consolidated Edison, Inc.
20 Eversource Energy
21 MGE Energy, Inc.
22 Northwestern Corp.
23 Sempra Energy
24 WEC Energy Group

25 I will refer to this group throughout my testimony as the Combination Utility

1 Group.

2
3 **Q. How does the Combination Utility Group compare on a total risk basis**
4 **to the Gas LDC Group?**

5 A. To facilitate a comparative risk assessment between the respective proxy groups
6 that I evaluated, I have compared the proxy groups on the basis of six well-
7 recognized measures of investment risk. The first of these measures is the Value
8 Line “beta,” which measures a stock’s non-diversifiable or systematic risk. The
9 second measure is the Value Line “Safety Rank,” which is Value Line’s proprietary
10 measure of the total risk of a stock and is determined based upon an equal
11 weighting between Value Line’s Financial Strength rating and Stock Price Stability
12 rating. I have also considered the Value Line Financial Strength and Stock Price
13 Stability ratings on an individual basis, which are presented as risk measures three
14 and four. The fifth and sixth measures of investment risk I have evaluated are the
15 long-term credit ratings assigned by S&P and Moody’s, respectively. Considering
16 that credit ratings are the product of a comprehensive, multi-dimensional analysis
17 which considers a utility’s business risk (including regulatory risk) and financial
18 risk, they provide a useful perspective into the overall investment risk profile of the
19 respective proxy groups.

20 The summarized results of my comparative risk assessment are presented
21 in Table VVR-4 later in my testimony. Based upon my evaluation of the
22 aforementioned risk measures, I have concluded that the Combination Utility
23 Group has a very similar investment risk profile as compared to the Gas LDC

1 Group. This conclusion is based upon the fact that the Combination Utility Group
2 and the Gas LDC Group have equivalent risk ratings with respect to the Value Line
3 Safety Ranking (“2”), Value Line Financial Strength rating (“A”), and Moody’s
4 long-term credit rating (“Baa1”). Although the Combination Utility Group’s
5 average Value Line beta (0.92) and Value Line Stock Price Stability Rating (85)
6 indicate a slightly higher level of investment risk as compared to the Gas LDC
7 Group’s average Value Line beta (0.91) and Stock Price Stability Rating (88), this
8 risk differential is offset by the lower level of investment risk implied by the
9 Combination Utility Group’s higher average S&P long-term credit rating (“A-”) as
10 compared to the Gas LDC’s Group’s average S&P long-term credit rating (“BBB+”).

11 **Q. Why is it also appropriate to evaluate a proxy group of non-rate-**
12 **regulated U.S. companies when estimating Columbia’s cost of equity?**

13 A. Under the fair rate of return standards established in *Hope* and *Bluefield*, the U.S.
14 Supreme Court determined that regulated utilities are entitled to earn a rate of
15 return commensurate with other companies having comparable risks, irrespective
16 of their business activities or the extent to which they are regulated. For example,
17 in *Bluefield*, the U.S. Supreme Court concluded:

18 A public utility is entitled to such rates as will permit it to earn a
19 return on the value of the property which it employs for the
20 convenience of the public equal to that generally being made at the
21 same time and in the same general part of the country on
22 investments in other business undertakings which are attended by
23 corresponding risks and uncertainties.⁸

⁸ *Bluefield Waterworks and Improvement Company v. Public Service Commission of the State of West Virginia*, 262 U.S. 679, 692 (1923).

1 It is important to note that within its *Bluefield* opinion, the Supreme Court
2 specifically stated that public utilities should be permitted to earn a return that is
3 equal to the returns on “*investments in other business undertakings*,” provided
4 they have corresponding risks. By virtue of its reference to “*other business*
5 *undertakings*,” the Supreme Court implicitly endorsed the use of non-utility proxy
6 groups in the determination of a fair rate of return for utilities. Furthermore, in
7 the *Hope* case, the Supreme Court concluded:

8 By that standard the return to the equity owner should be
9 commensurate with returns on investments in other enterprises
10 having corresponding risks.⁹

11 It is clear then, based upon the decisions of the Supreme Court in these landmark
12 cases, that the use of non-rate-regulated proxy companies in the determination of
13 a utility’s cost of equity is a sound practice, and is consistent with the comparable
14 earnings standard established in these cases. After all, utilities not only compete
15 with other utility companies for investor capital, they must also compete with an
16 entire universe of risk-comparable companies, irrespective of industry
17 classification and the level of regulatory oversight. Therefore, consistent with the
18 concept of opportunity cost, and to attract sufficient capital to support its public
19 service obligations, Columbia must provide a return to its investors that is similar
20 to the returns offered by non-rate-regulated companies of comparable risk.
21 Otherwise, over the long run, investor capital will simply flow to its most
22 productive use elsewhere.

⁹ *Federal Power Commission et al. v. Hope Natural Gas Company*, 320 U.S. 591, 603 (1944).

1 It is important to recognize that cost-of-service ratemaking is intended to be a
2 substitute for competition. That is, the objective of rate regulation is to produce
3 the same results that would be achieved under the forces of market competition.
4 In particular, it is the phenomenon of “competitive equilibrium” that rate
5 regulation is intended to replicate, where, in the long run, market forces limit
6 companies to earning returns that are no greater than, but also no less than,
7 investors’ minimum required rate of return. Expressed in microeconomic terms,
8 long-run equilibrium is achieved where firms only earn minimally-required levels
9 of “normal profits,” while excessive profits, often referred to as “economic profits,”
10 are by definition equal to zero. Accordingly, the returns of regulated utilities
11 should be no lower than the returns of comparable-risk companies that operate
12 under the constraints of market competition. Each of the companies I have
13 selected for inclusion in my Non-Regulated Group operate under the competitive
14 pressures of the free marketplace. Considering that this proxy group is comparable
15 on a total risk basis to the Gas LDC Group and Columbia, its use is consistent with
16 the fair rate of return standards established in *Hope* and *Bluefield*.

17 **Q. What criteria did you use to select the companies included in the Non-**
18 **Regulated Group?**

19 A. In selecting the Non-Regulated Group, my objective was to identify a group of
20 publicly traded domestic companies with a risk profile equivalent to, or marginally
21 lower than, the Gas LDC Group. This approach is designed to ensure a
22 conservative analysis when applying the various cost of equity models to the Non-
23 Regulated Group companies. In this regard, I applied the following screening

1 criteria in selecting companies for inclusion in the Non-Regulated Group: (i) Value
2 Line Investment Survey Classification as a Conservative Stock, which is defined as
3 stocks having a Value Line Safety Rank of no lower than “1” (Highest Rank for
4 Relative Safety); (ii) Value Line beta ranging between 0.80 and 1.00; (iii) Value
5 Line Financial Strength Rating of “A+” or higher; (iv) S&P corporate credit rating
6 that is no lower than BBB-, or Moody’s long-term issuer rating of no lower than
7 Baa3; (v) company shall not be in the gas and/or electric distribution business, and
8 shall not be an investment, financial services, pharmaceutical, life sciences,
9 medical technology, hardware/software, or defense contract company; (vi) the
10 company must currently pay dividends and must not have discontinued or reduced
11 their dividend payments during the previous five years (2019-2023); and (vii) the
12 company must have at least one consensus earnings estimate published by an
13 information service provider such as Thomson Reuters or Zacks. Applying these
14 highly-selective criteria yielded the Non-Regulated Group, which is comprised of
15 nine lower-risk companies which operate in the consumer staple, food and
16 beverage, chemicals processing, waste management and industrial products
17 manufacturing sectors of the economy. The nine companies comprising the Non-
18 Regulated Group are as follows:

19 Air Products and Chemicals, Inc.

20 Brown-Forman Corp.

21 Coca-Cola Co.

22 Home Depot, Inc.

23 IDEX Corporation

24 Illinois Tool Works

McDonald's Corp.
Mondelez International
Republic Services, Inc.

Q. How does the Non-Regulated Group compare on a total risk basis to the Gas LDC Group?

A. Based upon my evaluation of the aforementioned risk measures, and as reflected in Table VVR-4 below, I have concluded that the Non-Regulated Group has a slightly lower risk profile as compared to the Gas LDC Group. This is demonstrated by the fact that although the Non-Regulated Group and the Gas LDC Group share the same average Value Line beta coefficient of 0.91, each of the other five risk measures reflected in Table VVR-4 below indicate that the Non-Regulated Group has a lower risk profile than the Gas LDC Group.

Table VVR-4 Comparative Risk Assessment of Proxy Groups			
Risk Measure	Gas LDC Group	Comb. Utility Group	Non- Reg. Group
Value Line Beta	0.91	0.92	0.91
Value Line Safety Rank	2	2	1
Value Line Fin. Strength Rating	A	A	A+
Value Line Stock Price Stability Rating	88	85	96
S&P Long-Term Debt Rating	BBB+	A-	A-
Moody's Long-Term Debt Rating	Baa1	Baa1	A3

C. Analysis of Regulatory Mechanisms

Q. Have you compared the extent to which Columbia currently utilizes regulatory mechanisms, including revenue decoupling and infrastructure cost recovery mechanisms, as compared to the Gas LDC Group companies? If, yes, what conclusions did you arrive at based upon your evaluation?

A. On the first question, yes, I have compared the regulatory mechanisms that are currently utilized or proposed by the Company in this proceeding to the various forms of regulatory mechanisms utilized by the Gas LDC Group companies. On

1 the second question, I have concluded that the majority of the Gas LDC Group
2 companies already utilize the same types of regulatory mechanisms that Columbia
3 either currently utilizes or has proposed in this proceeding. Therefore, any
4 theoretical risk reduction and associated reduction in the cost of equity resulting
5 from these mechanisms would already be reflected in the market prices of the Gas
6 LDC Group companies. In other words, since investors are already aware of the
7 mechanisms employed by the Gas LDC Group companies, they have already
8 incorporated these mechanisms into their risk perceptions and rate of return
9 expectations.

10 As further discussed in the direct testimony of Company witness John D. Taylor
11 (Statement No. 17), Columbia has made several proposals in this proceeding which
12 would facilitate a more cost-based rate design for the Company by: (1) increasing
13 its fixed cost recovery through an increase to its fixed customer charges; (2)
14 approving the Company's current pilot WNA mechanism as a permanent program;
15 and (3) adopting a RNA mechanism for non-CAP residential and C&I customers.
16 If adopted, these mechanisms would essentially put the Company on a more equal
17 footing with the Gas LDC Group companies. However, to the extent that the
18 Company's proposals regarding the WNA, RNA and increase to the fixed customer
19 charge are not adopted, I have concluded, that as a result of the absence of these
20 regulatory mechanisms, the Company's risk profile will be relatively higher than
21 the Gas LDC Group, which serves as the underlying basis for estimating Columbia's
22 cost of equity. Under these circumstances, the Gas LDC Group's estimated cost of
23 equity would understate the market required return for Columbia.

1 **Q. Please elaborate further on the review you conducted to determine the**
2 **extent to which the companies comprising the Gas LDC Group utilize**
3 **revenue stabilization mechanisms?**

4 A. To ensure completeness, I reviewed the revenue stabilization mechanisms
5 currently utilized by each of the companies comprising the Gas LDC Group. The
6 results of my review are presented in Exhibit VVR-3. Using information available
7 from Securities and Exchange Commission filings and investor conference
8 presentations, my evaluation identified, for each state jurisdiction in which the
9 proxy group companies have utility operations, the specific types of revenue
10 stabilization mechanisms employed in each of those jurisdictions. During the
11 course of my evaluation, I determined that a wide range of revenue stabilization
12 mechanisms are employed by the companies comprising the Gas LDC Group,
13 including full decoupling, revenue normalization, weather normalization, rate
14 stabilization, straight or modified fixed-variable rate design, and lost revenue/lost
15 margin recovery mechanisms.

16 **Q. Based upon your evaluation of the revenue stabilization mechanisms**
17 **employed by the Gas LDC Group companies, what conclusions have**
18 **you drawn?**

19 A. Based on my review, I determined that all of companies comprising the Gas LDC
20 Group utilize rate designs that are either fully or partially non-volumetric in
21 nature. Along these lines, Exhibit VVR-3 demonstrates that, on balance, the
22 revenue stabilization mechanisms employed by the Gas LDC Group companies are
23 generally more comprehensive than Columbia's current WNA program. This is

1 the case because the majority of the Gas LDC Group companies utilize revenue
2 normalization or rate stabilization mechanisms which also address non-weather
3 related causes of revenue variability, such as the impacts associated with
4 conservation and energy efficiency programs. However, to the extent that the
5 Company's proposals pertaining to its WNA, RNA and fixed customer charge
6 mechanisms and rate designs are adopted by the Commission in this proceeding,
7 this would serve to put the Company's regulatory mechanisms more "on par" with
8 the companies comprising the Gas LDC Group.

9 **Q. Based upon your evaluation of the infrastructure cost recovery**
10 **mechanisms employed by the Gas LDC Group companies, what**
11 **conclusions have you drawn?**

12 A. As noted earlier, in determining the extent to which the Gas LDC Group companies
13 utilize infrastructure cost recovery mechanisms, I employed the same approach
14 that investors typically employ in conducting their relative risk assessments among
15 various investment alternatives. That is, I reviewed each company's SEC public
16 filings (i.e. 10-Ks and 10-Qs) and investor conference presentations. This is an
17 important observation since investors will generally form their risk perceptions
18 with respect to the impacts of infrastructure cost recovery mechanisms largely on
19 the basis of the information contained within a company's public filings and/or
20 other publicly disseminated information.

21 As presented in Exhibit VVR-3, I have determined that all of the Gas LDC Group
22 companies either utilize infrastructure cost recovery tracking mechanisms or
23 employ forward test years that enable the company to recover its infrastructure

1 investments on a timelier basis than would otherwise be possible in a traditional
2 rate proceeding or through the use of a historical test year. Therefore, on balance,
3 the infrastructure tracking mechanisms and/or forward test years employed by the
4 Gas LDC Group companies are generally comparable to Columbia's Distribution
5 System Improvement Charge ("DSIC") and the Company's use of a fully projected
6 future test year. Therefore, any theoretical risk reduction resulting from the
7 reduced regulatory lag associated with the Company DSIC and/or fully projected
8 future test year will have already been captured in the market-based data of the
9 Gas LDC Group companies, and therefore the cost of equity estimates yielded from
10 my evaluation of the Gas LDC Group.

V. RATE-SETTING CAPITAL STRUCTURE AND EMBEDDED COST OF DEBT

Q. Does Exhibit VVR-5 provide the Company's capitalization and capital structure ratios for the respective test years in this proceeding?

A. Yes. Exhibit VVR-5 presents the Company's capitalization and capital structure ratios for the respective test periods in this proceeding. The November 30, 2024 capitalization corresponds with the end of the historical test year ("HTY"). The November 30, 2025 capital structure is estimated at the end of the future test year ("FTY"), and the December 31, 2026 capital structure is estimated at the end of the fully projected future test year ("FPFTY"). The Company expects to issue \$40.0 million of new long-term debt in the FTY, \$155.0 million of new long-term debt between the FTY and the FPFTY and \$165.0 million of new long-term debt in the FPFTY. A debt maturity in the amount of \$54.515 million will also occur in the FTY. A projection of retained earnings has been reflected in the FTY and FPFTY, including an assumption of no dividend payments during the FTY and \$50 million of dividend payments during the FPFTY.

Q. What capital structure ratios are you recommending for rate-setting purposes in this proceeding?

A. Considering that the rate-setting process is prospective in nature, the Company's authorized rate of return should incorporate known and foreseeable changes expected to occur during the course of the FPFTY, including those changes impacting the Company's capital structure. For this reason, I will adopt the Company's FPFTY capital structure ratios of 43.28 percent long-term debt, 2.32

1 percent short-term debt, and 54.40 percent common equity at December 31, 2026.
2 For short-term debt, I have used the twelve-month average balance for the FPFTY.
3 These capital structure ratios are the best approximation of the mix of capital the
4 Company will employ to finance its rate base during the period new rates are in
5 effect. Exhibit VVR-4 and Exhibit VVR-5 presents Columbia's total capitalization
6 levels and corresponding capital structure ratios for each of the respective test
7 years in this proceeding.

8 **Q. How does Columbia's proposed equity capitalization ratio compare to**
9 **the equity capitalization ratios for the Gas LDC Group holding**
10 **companies?**

11 A. To confirm the reasonableness of the Company's FPFTY capital structure, I have
12 evaluated the actual and projected equity capitalization levels published by Value
13 Line for the Gas LDC Group companies, which are calculated on the basis of
14 permanent capitalization, and therefore exclude short-term debt. On an
15 equivalent permanent capitalization basis, the Company's equity capitalization
16 level is estimated to be 55.7 percent ($\$2,125,309,877 / \$3,816,309,877$) as of
17 December 31, 2026, which excludes the impact of short-term debt. As reflected in
18 Table VVR-5 below, this capitalization level is well within the range of equity
19 capitalization ratios anticipated for the gas utility holding companies comprising
20 the Gas LDC Group, as based upon near-term forecasts from Value Line.

Table VVR-5 Forecasted Equity Capitalization Ratios Gas LDC Group				
Company	2024 (Actual)	2025	2026	2028- 2030
Atmos Energy Corp.	60.7%	60.0%	60.0%	60.0%
NiSource Inc.	46.0%	46.0%	45.0%	45.0%
Northwest Natural Gas Co.	47.5%	45.0%	45.0%	45.0%
ONE Gas, Inc.	54.0%	55.0%	55.0%	55.0%
Southwest Gas Holdings, Inc.	45.0%	45.0%	45.0%	44.0%
Spire Inc.	43.1%	43.0%	43.0%	45.0%
Gas LDC Group Range	43.1% - 60.7%	43.0% - 60.0%	43.0% - 60.0%	44.0% - 60.0%
Columbia Gas of Pennsylvania	55.7%	55.7%	55.7%	55.7%
Source: Value Line Investment Survey, February 21, 2025.				

This data indicates that Columbia's proposed capital structure ratios fall within the typical and customary range for gas utility holding companies. While the Company's FPFTY common equity ratio measured on an equivalent basis is 55.7 percent, the actual and forecasted common equity ratios for the Gas LDC Group companies range from 43.0 percent to 60.7 percent. Accordingly, the Company's proposed FPFTY equity capital ratio falls well within this range, and is therefore reasonable and customary for a gas utility company.

Q. How does Columbia's proposed equity capitalization ratio compare to the equity capitalization ratios either adopted by the Commission or proposed by gas utility companies in Pennsylvania over the past four years?

A. In Table VVR-6 below, I present the equity capitalization ratios either adopted by the Commission or proposed by gas utility companies in Pennsylvania over the past

four years. In view of the significant number of black box settlements in recent years, it was necessary to consider not only the equity capitalization ratios that were explicitly adopted by the Commission, but also the proposed equity capitalization ratios in those cases where the final order in the case was silent with respect to the equity capitalization ratio. On that basis, the average equity capitalization ratio either adopted by the Commission, or, in the absence of such adoption, proposed by the utility over the past four years has averaged 54.22 percent, which includes short-term debt. Therefore, Columbia's proposed equity capitalization ratio of 54.40 percent is closely comparable to the 54.22 percent average equity capitalization ratio (either authorized by the Commission or proposed by the utility) for Pennsylvania's gas utility companies over the past four years.

Table VVR-6 Recent Outcomes of Gas Rate Proceedings in Pennsylvania				
Year of Decision	Company	Proposed ROE	Authorized ROE	Proposed Equity Ratio
2024	Columbia Gas (2024-3046519, Settled)	11.75%	Black Box	54.40%
2022	Columbia Gas (2022-3031211, Settled)	11.20%	Black Box	54.38%
2021	Columbia Gas (2021-3024296, Settled)	10.95%	Black Box	54.34%
2021	Columbia Gas (2020-3018835, Litigated)	10.95%	9.86%	54.19%
2023	National Fuel Gas (2022-3035730, Settled)	11.20%	Black Box	54.90%
2024	PECO Energy Co. (2024-3046932, Settled)	11.15%	Black Box	53.40%
2022	PECO Energy Co. (2022-3031113, Settled)	10.95%	Black Box	53.41%

2021	PECO Energy Co. (2020-3018929, Litigated)	10.95%	10.24%	53.38%
2024	Peoples Natural Gas (2023-3044549, Settled)	11.75%	Black Box	54.67%
2022	UGI Utilities (2021-3030218, Settled)	11.20%	Black Box	55.09%
2021-2024 Average	All Gas Utility Rate Proceedings	n/a	n/a	54.22%

Q. How does Columbia’s proposed equity capitalization ratio compare to the recently authorized equity capitalization ratios for other gas utility companies nationwide over the past few years?

A. As recently reported by Regulatory Research Associates (“RRA”)¹⁰, the average equity capitalization ratios authorized by U.S. regulatory commissions for gas utility operating companies nationwide was 52.13 percent and 52.45 percent, respectively, for 2024 and 2025. Therefore, the Company’s proposed equity capitalization ratio of 54.50 percent is reasonably consistent with the national averages of gas utility companies in recent years.

Q. What cost of debt did you apply to the long-term debt component of Columbia’s capital structure?

A. As reflected on page 1 of Exhibit VVR-6, the Company’s actual embedded cost of long-term debt at November 30, 2024, the end of the HTY, is 4.92 percent. As shown on page 2 of Exhibit VVR-6, the embedded cost of long-term debt estimated for the Company at November 30, 2025, the end of the FTY, is also 4.92 percent.

¹⁰ *Major Energy Rate Case Decisions in the U.S., January - December 2024*, RRA Regulatory Focus, S&P Global Market Intelligence (February 4, 2025), at 6.

1 In the FTY, the \$40.0 million debt issuance anticipated during June 2025 reflects
2 an estimated interest rate of 6.50 percent. Lastly, as shown on page 3 of Exhibit
3 VVR-6, the embedded cost of long-term debt estimated for the Company at
4 December 31, 2026, the end of the FPFTY, is 5.22 percent. For the new issuances
5 of long-term debt occurring in December 2025 and December 2026, I have used
6 an estimated interest rate of 6.50 percent. In each instance of new long-term debt
7 issuances, the estimated interest rates reflected in Exhibit VVR-6 were determined
8 by referencing the Bloomberg forward yield curve on 30-year U.S. Treasury bonds
9 and then adding the corporate credit yield spread that corresponds to NiSource's
10 long-term credit rating at S&P, which is "BBB+".

11 **Q. What cost of debt did you apply to the short-term debt component of**
12 **Columbia's capital structure?**

13 A. I have used a cost of short-term debt of 5.00 percent, which represents the
14 Company's estimate for the FPFTY. It should be noted that the Company's actual
15 short-term debt interest rate in the HTY was 5.5367 percent. The Company
16 obtains its short-term debt from the NiSource intra-system financing vehicle,
17 commonly referred to as the "money pool", which has commercial paper as its
18 underlying source. The proposed short-term interest rate in this case was
19 determined on the basis of the forecast of the Federal Funds target rate of 4.00
20 percent, plus 0.50 percent, which reflects the recent historical yield differential
21 between the Fed Funds rate and the commercial paper borrowing rate for
22 NiSource's commercial paper credit rating of A-2 at S&P and P-2 at Moody's for a
23 75-day duration, plus an additional 0.50 percent risk premium to recognize the

1 uncertainly surrounding the degree to which the Federal Reserve Board will
2 continue reducing the Federal Funds target rate.

3 **Q. What overall debt cost rate have you determined is appropriate for rate**
4 **of return purposes in this proceeding?**

5 A. As reflected on page 3 of Exhibit VVR-6, the combined cost of long-term and short-
6 term debt is 5.21 percent for the FPFTY.

7 **VI. COST OF EQUITY ESTIMATES**

8 **A. Cost of Equity - General Approach**

9 **Q. Please describe the general approach you have taken in estimating the**
10 **cost of equity for Columbia.**

11 A. In order to facilitate a thorough analysis of Columbia's cost of equity, I first
12 conducted a comparative risk assessment to establish the risk relationships
13 between Columbia and the three respective proxy groups. I then determined the
14 indicated cost of equity for each of the respective proxy groups by applying three
15 widely-recognized cost of equity models to the market and/or financial data of the
16 proxy group companies. To estimate Columbia's cost of equity, I started with the
17 indicated cost of equity for the respective proxy groups for each of the analytical
18 methods employed and then determined if any further return adjustments were
19 required based upon the results of my comparative risk assessment.

20 It should be noted that although the cost of equity cannot be directly
21 observed, it can be estimated using a variety of analytical models, each of which
22 attempt to explain and/or predict investor behavior. However, since investor

1 expectations often differ and investors rely on a variety of information sources and
2 financial models to make their investment decisions, no single analytical model
3 can possibly capture the broader universe of investor expectations. Moreover, each
4 financial model has its own practical shortcomings, either in the form of rigid
5 underlying assumptions or required model inputs which are dependent upon the
6 subjective judgment of the analyst. For these reasons, in *The Cost of Capital - A*
7 *Practitioner's Guide*, Parcell presents a compelling argument for the use of a
8 variety of analytical methods in estimating a utility's cost of equity, and cautions
9 against overreliance on any one particular model. In *The Cost of Capital*, Parcell
10 maintains:

11 no single model is so inherently precise that it can be relied upon
12 solely to the exclusion of other theoretically sound models...Each
13 model has its own way of examining investor behavior, its own
14 premises, and its own set of simplifications of reality...Investors
15 clearly do not subscribe to any singular method, nor does the stock
16 price reflect the application of any one single method by investors.
17 Therefore, it is essential that estimates of investors' required rate of
18 return produced by one method be compared with those produced
19 by other methods, and that all cost of equity estimates be required to
20 pass fundamental tests of reasonableness and economic logic.¹¹

21 Consistent with the foregoing arguments articulated by Parcell, to ensure a
22 thorough evaluation of Columbia's cost of equity, I have applied a variety of
23 analytical models to the market and/or financial data of a large number of proxy
24 group companies.

¹¹ David C. Parcell, *The Cost of Capital - A Practitioner's Guide* (Society of Utility and Regulatory Financial Analysts, 2020 Edition), at 86.

B. Discounted Cash Flow (“DCF”) Analysis

Q. Please provide an overview of the DCF approach used to estimate the cost of equity.

A. The DCF approach is a commonly used valuation model, which is based on the fundamental premise that investors value financial assets on the basis of their expected future cash flows, discounted by an appropriate risk-adjusted rate of return. The model maintains that the market-determined price of a share of common stock or other financial asset will continually adjust until investors are sufficiently compensated for the level of investment risk they bear. It is only at the point that investors have realized their required rate of return that valuation equilibrium will have been achieved. The objective of the DCF approach is to reproduce this iterative market valuation process in the form of a financial model. Considering that the price of a given share of common stock can be directly observed in the equity market, and that the stock’s future dividends and capital gains can be estimated, the DCF model can be successfully rearranged to solve for the cost of common equity. It is this “rearranged” version of the DCF model that is commonly used in utility rate proceedings, as I will discuss later in my testimony.

Q. What is the underlying theoretical basis for employing the DCF approach to value financial assets, and how has the DCF approach evolved over the years?

A. The theoretical underpinnings of the DCF approach are consistent with classical valuation theory, which states that the intrinsic value of any security is a function of its future earnings power. Specifically, intrinsic value can be quantified as the

1 present value of the security's future cash flows discounted at the appropriate risk-
2 adjusted rate of return. This concept was first formally advanced by Fisher in *The*
3 *Rate of Interest*,¹² and was further elaborated upon in his subsequent work, *The*
4 *Theory of Interest*, wherein Fisher maintained:

5 Capital, in the sense of capital value, is simply future income
6 discounted or, in other words, capitalized. The value of any property,
7 or rights to wealth, is its value as a source of income and is found by
8 discounting that expected income.¹³
9

10 Fisher's seminal valuation concept, which was first articulated over a century ago,
11 laid the foundation for modern versions of the DCF approach, which both investors
12 and academics continue to rely upon today.

13 Almost a decade after *The Theory of Interest* was published, Williams
14 expanded upon Fisher's earlier work in valuation theory in his classic publication,
15 *The Theory of Investment Value* (1938). It was here that Williams first expressed
16 in modern economic terms a fully developed DCF equation, which was intended to
17 serve as a valuation model for common stocks. Although Williams emphasized
18 that his DCF equation was a *dividend* discounting model rather than an earnings-
19 based model, he also acknowledged that over the long run, the two approaches
20 would produce equivalent valuation results. Indeed, upon introducing his DCF
21 equation in *The Theory of Investment Value*, Williams explains:

22 Let us define the investment value of a stock as the present worth of
23 all the dividends to be paid upon it....

24 Most people will object at once to the foregoing formula for stocks by
25

¹² Irving Fisher, *The Rate of Interest*, (The Macmillan Company 1907).

¹³ Irving Fisher, *The Theory of Interest*, (The Macmillan Company 1930), Part I, Chapter I, Section 7.

1 saying that it should be the present worth of future *earnings*, not
2 future *dividends*. But should not earnings and dividends both give
3 the same answer under the implicit assumptions of our critics? If
4 earnings not paid out in dividends are all successfully reinvested at
5 compound interest for the benefit of the stockholder, as the critics
6 imply, then these earnings should produce dividends later; if not,
7 then they are money lost....

8
9 On analysis, therefore, it will be seen that no contradiction really
10 exists between our formula using dividends and the common precept
11 regarding earnings. How to estimate the future dividends for use in
12 our formula is, of course, the difficulty.¹⁴
13

14 The DCF approach introduced by Williams included a general “long-form”
15 equation, which reflected an ongoing series of dividend payments extending into
16 the indefinite future, and a simplified constant growth version of the equation,
17 which was later refined by Gordon and Shapiro.¹⁵

18 In subsequent years, Williams’ long-form DCF equation was adjusted to
19 accommodate various forms of future cash flows, rather than only dividends, and
20 evolved into a general purpose valuation model. This so-called “general DCF
21 model” continues to be used today in a variety of applications extending beyond
22 security valuation, including corporate finance decision support, real estate
23 development, and other financial applications. However, when the general DCF
24 model is employed to value common stocks, the following equation is utilized:

25
26
$$P_0 = D_1 / (1+K) + D_2 / (1+K)^2 + D_3 / (1+K)^3 + \dots + D_n / (1+K)^n \quad (\text{Equation 1.1})$$

¹⁴ John Burr Williams, *The Theory of Investment Value*, (Cambridge, MA, Harvard University Press, 1938) 55, 57-58.

¹⁵ Myron J. Gordon and Eli Shapiro, “Capital Equipment Analysis: The Required Rate of Profit,” *Management Science*, 3 (October 1956) 102-110.

Where: P_0 = current market price of the stock,
 D_1 = expected dividend at end of year 1, year 2, year 3, etc.,
 n = infinity,
 K = investors' expected return on equity (the discount rate).

Q. What form of the DCF model is used to estimate the cost of common equity in utility regulatory proceedings?

A. In practice, the general DCF model can be challenging to apply to common stock valuation, since the model requires that discrete dividend payments be estimated well into the distant future. However, if investors assume that future dividend payments will increase at a constant growth rate each year into perpetuity, the valuation process can be greatly simplified. Drawing upon the constant growth model developed by Williams, and later refined by Gordon and Shapiro, the following constant growth equation can be utilized in valuing common stocks:

$$P_0 = D_1 / (K - g) \quad (\text{Equation 1.2})$$

Where: P_0 = current market price of the stock,
 D_1 = expected dividends over the next year,
 K = investors' expected return on common equity (the discount rate),
 g = expected dividend growth rate into perpetuity.

This simplified equation states that a company's stock price is determined by the present value of dividend payments occurring over the next year, plus all subsequent dividend payments growing at a constant annual rate, as discounted by the expected return on common equity. Although the constant growth model is conceptually viable and simplifies the process of estimating future dividend

1 payments, the model is also premised upon strict underlying assumptions,¹⁶ which
2 are not always observed in reality.

3 The constant growth equation reflected above can be rearranged to solve for “K,”
4 which yields the standard DCF formulation for estimating the cost of common
5 equity, which is expressed as follows:

$$K = D_1/P_0 + g \quad (\text{Equation 1.3})$$

7 Where: Variables are as previously defined.

8 It is this standard form of the DCF model that is commonly used in utility rate
9 proceedings. The model is intuitive in that it states that common stock investors
10 have a total return requirement (“K”) which is comprised of a forward looking
11 dividend yield component (D_1/P_0), plus the expected growth rate of dividends
12 (and/or stock price appreciation) into perpetuity (“g”). Considering that both
13 components of the dividend yield (D_1 and P_0) can be readily observed through a
14 variety of publicly-available sources, and that the investor expected growth rate
15 can be estimated using a variety of approaches, the analyst can infer “K,” the
16 required return on common equity.

17 **Q. What steps are involved in implementing the constant-growth DCF**

¹⁶ The strict assumptions underlying the constant growth DCF model include: (i) dividends and earnings grow at the same constant growth rate (or constant average growth trend); (ii) book value per share and the stock price also grow at the same constant growth rate; (iii) investors expect the same rate of return (“K”) in all future periods, implying no changes in risk and a flat yield curve; (iv) the discount rate, “K,” must exceed the expected constant growth rate, “g”; (v) a fixed dividend payout ratio will be maintained; (vi) a fixed price-earnings (“P/E”) multiple will be maintained; (vii) dividends are only paid at the end of each year; and (viii) no external financing occurs, as growth is financed strictly through the retention of earnings (or alternatively, any new sales of stock only occur at book value). Despite the fact that these assumptions are not always reflective of reality, the constant growth model maintains its usefulness due in its ability to adequately explain investor behavior and the stock market valuation process.

model for estimating the cost of common equity?

A. Implementing the DCF model involves three essential steps. The first step is to determine the expected dividend yield component (D_1/P_0), which is defined as dividends expected to be paid over the next twelve months (D_1) divided by the current stock price (P_0). From an investor's perspective, the dividend yield represents *current income*. The second step is to estimate the long-term growth expectations of investors, or "g," relative to the security's future dividends and/or price appreciation. From the investor's perspective, whether realized in the form of higher future dividend payments, or in the form of stock price appreciation, the growth component represents *future income*. Considering that a strict interpretation of constant-growth theory requires that a *perpetual* growth rate be estimated, while the available sources of forward-looking growth estimates are limited in their forecast horizons, determining an appropriate growth estimate is the most challenging and controversial aspect of the DCF approach. The third and final step is simply to sum together the expected dividend yield component with the expected long-term growth component, to determine "K," the investor required cost of common equity.

A detailed discussion of the steps I took in implementing the DCF constant growth model can be found in Appendix A to my testimony. Additionally, Appendix B discusses the treatment of "outlier" DCF results which do not meet threshold tests of reasonableness and economic logic. Appendix C discusses the importance of applying a financial risk adjustment to DCF estimates whenever the market-value equity capitalization level of the proxy group companies is materially

1 different than the corresponding book-value capitalization levels. Exhibit VVR-10
2 also further supports the discussions covered in Appendix C. Finally, Appendix D
3 discusses the importance of applying a flotation cost adjustment to the “baseline”
4 cost of equity results under the DCF model.

5 **Q. What cost of equity estimates are indicated for the Gas LDC Group**
6 **using the DCF approach?**

7 A. A detailed presentation of DCF results for each member of the Gas LDC Group is
8 presented on pages 1 and 2 of Exhibit VVR-7 and is also summarized in Table VVR-
9 7 below. After eliminating outlier results, the average unadjusted DCF estimate for
10 the Gas LDC Group ranged from 10.00 percent to 10.70 percent. The three
11 unadjusted DCF estimates based upon earnings growth forecasts, which my
12 evaluation places the greatest emphasis upon, demonstrate a central tendency of
13 approximately 10.45 percent. The DCF estimate based upon the 5-year and 10-
14 year historical average earnings growth rate indicates an unadjusted cost of equity
15 of 10.00 percent. On an overall basis, an unadjusted DCF estimate of 10.30 percent
16 is indicated for the Gas LDC Group. In deriving this estimate, I placed the greatest
17 emphasis on the EPS growth estimates of equity analysts, which have been
18 demonstrated to have a significant influence on stock prices. After making the
19 required leverage and flotation cost adjustments to the unadjusted DCF estimate
20 referenced above, the results of my analysis indicate a cost of equity of 10.97
21 percent for the Gas LDC Group.

Table VVR-7 Average DCF Estimates - Gas LDC Group	
Calculation Method	Cost of Equity
Earnings Forecast	
S&P Global	10.70%
Zacks	10.10%
Value Line	10.50%
Historical Earnings Growth Rate	10.00%
Unadjusted DCF Estimate	10.30%
Flotation Cost (3 basis points)	x 1.002625
Subtotal	10.33%
Plus: Financial Leverage Risk Adjustment for Market Value vs. Book Value Capital Structure ¹⁷	0.64%
Indicated DCF Estimate	10.97%

Q. What cost of equity estimates were indicated for the Combination Utility Group using the DCF approach?

A. DCF estimates for each member of the Combination Utility Group are presented on pages 1 and 2 of Exhibit VVR-8 and are summarized in Table VVR-8 below. After eliminating outlier results, the unadjusted DCF estimates for the Combination Utility Group ranged from 9.50 percent to 10.10 percent. The three unadjusted DCF estimates based upon earnings growth forecasts demonstrate a central tendency of approximately 9.85 percent. The DCF estimate based upon the

¹⁷ Further support for this financial leverage risk adjustment is provided in Appendix C to my Direct Testimony.

5-year and 10-year historical average earnings growth rate indicates an unadjusted cost of equity of 9.50 percent. On an overall basis, an unadjusted DCF estimate of 9.90 percent is indicated for the Combination Utility Group. After making the required leverage and flotation cost adjustments to the unadjusted DCF estimate, the results of my analysis indicate a cost of equity of 10.57 percent for the Combination Utility Group.

Table VVR-8 Average DCF Estimates – Combination Utility Group	
Calculation Method	Cost of Equity
Earnings Forecast	
S&P Global	10.00%
Zacks	10.10%
Value Line	9.50%
Historical Earnings Growth Rate	9.50%
Unadjusted DCF Estimate	9.90%
Flotation Cost (3 basis points)	x 1.002625
Subtotal	9.93%
Plus: Financial Leverage Risk Adjustment for Market Value vs. Book Value Capital Structure ¹⁸	0.64%
Indicated DCF Estimate	10.57%

Q. What cost of equity estimates were indicated for the Non-Regulated Group using the DCF approach?

A. DCF estimates for each member of the Non-Regulated Group are presented on

¹⁸ Id.

1 pages 1 and 2 of Exhibit VVR-9 and are summarized in Table VVR-9 below. After
2 eliminating outlier results, the unadjusted DCF estimates for the Non-Regulated
3 Group ranged from 9.80 percent to 11.60 percent. The three unadjusted DCF
4 estimates based upon earnings growth forecasts demonstrate a central tendency of
5 approximately 10.65 percent. The DCF estimate based upon the 5-year and 10-
6 year historical average earnings growth rate indicates an unadjusted cost of equity
7 of 10.20 percent. On an overall basis, an unadjusted DCF estimate of 10.60 percent
8 is indicated for the Non-Regulated Group. After making the required flotation cost
9 adjustment to this estimate, the results of my DCF analysis indicate a cost of equity
10 of 11.27 percent for the Non-Regulated Group.

Table VVR-9 Average DCF Estimates – Non-Regulated Group	
Calculation Method	Cost of Equity
Earnings Forecast	
S&P Global	10.60%
Zacks	9.80%
Value Line	11.60%
Historical Earnings Growth Rate	10.20%
Unadjusted DCF Estimate	10.60%
Flotation Cost (3 basis points)	x 1.002625
Subtotal	10.63%
Plus: Financial Leverage Risk Adjustment for Market Value vs. Book Value Capital Structure ¹⁹	0.64%
Indicated DCF Estimate	11.27%

Consistent with established regulatory principles, authorized returns for regulated utilities should be similar to returns offered by comparable risk firms operating in the competitive marketplace.

C. Capital Asset Pricing Model (“CAPM”) Analysis

Q. Please provide an overview of the CAPM and the theoretical basis for using it to estimate a utility’s cost of equity.

A. The CAPM is a market-based risk and return investment model which derives its theoretical underpinnings from both Capital Market Theory and Modern Portfolio Theory (“MPT”).²⁰ Originally developed by Sharpe in the early 1960s for

¹⁹ Id.

²⁰ MPT, which was developed by Harry Markowitz in the early 1950’s, heavily influenced William Sharpe’s development of the CAPM. MPT advanced the concept of an “efficient frontier” of dominating investment

investment analysis purposes, the CAPM is considered an ex-ante, forward-looking model which recognizes that investors are generally risk-averse and will demand higher returns in exchange for assuming higher levels of investment risk.

The traditional CAPM equation is expressed as follows:

$$K = R_F + \beta(R_M - R_F) \quad (\text{Equation 1.4})$$

Where: K = Required rate of return for a stock;
 R_F = Expected risk-free rate of return;
 β = Beta, or systematic risk of a stock; and
 R_M = Expected return for the overall stock market.

The investor required rate of return (K) indicated by the CAPM is equal to the expected risk-free rate of return (R_F) plus a risk premium which is proportional to the level of systematic risk implicit in the security being evaluated. Systematic risk, also referred to as market risk, is the sole risk element found within the CAPM, and refers to the variability of overall stock market returns, which are largely influenced by socioeconomic and political trends. It is only this systematic risk which commands a return premium within the CAPM, as a critical assumption underlying the model is that investors have already eliminated firm-specific investment risk in their investment portfolios via diversification.

Within the CAPM framework, an individual stock's contribution to the systematic risk of a given portfolio is indicated by the stock's beta (β) coefficient.

portfolios, which provided the highest rate of return possible for a given level of investment risk, as measured by the portfolio's covariance of returns. Essential concepts from MPT which influenced the development of the CAPM included the risk and return tradeoff relationship, and the value of diversification for eliminating firm-specific investment risk. Markowitz and Sharpe both earned the Nobel Prize in Economics in 1990 for their body of work relative to these classic financial theories.

1 In essence, the beta coefficient measures the co-variability of the price movements
2 of an individual stock versus the price movements of the total market portfolio.
3 The beta of the market portfolio is equal to 1.0, which reflects a level of variability
4 consistent with the overall stock market. Stocks with beta values *lower* than 1.0
5 have a lower expected variability and therefore less systematic risk than the overall
6 market, while stocks with betas *higher* than 1.0 have a higher expected variability
7 and thus greater systematic risk than the overall market. To determine the
8 investor-required risk premium for an individual stock, the difference between the
9 expected market return (R_M) and the expected risk-free rate of return (R_F), which
10 is defined as the market risk premium ($R_M - R_F$), is proportionately adjusted based
11 upon the stock's beta. Lastly, the investor required rate of return (K) is determined
12 by adding the expected risk-free rate of return to the stock-specific risk premium.

13 Much like other analytical models including the DCF model, the CAPM is
14 premised upon strict underlying assumptions, which are not always observed in
15 reality.²¹ Nonetheless, the model still possesses useful explanatory and predictive
16 abilities, as it has been consistently demonstrated that beta is both positively and
17 linearly correlated to security returns. At the same time, as I will discuss later in
18 my testimony, empirical studies have also demonstrated that the risk-return
19 relationship indicated by the CAPM, as graphically depicted by the Security Market

²¹ The strict assumptions underlying the CAPM include: (i) security markets are highly efficient and consistently reflect the true value of a given security; (ii) investors will always pursue their own best economic self-interest, including the maximization of profit and end-of-period wealth; (iii) all investors have the same rate of return expectations; (iv) all investors hold diversified investment portfolios; and (v) investors are not subject to taxes, transaction costs, short-selling restrictions or borrowing restrictions.

Line (“SML”), is in reality not as steeply sloped as the model implies. In fact, the empirical evidence has shown that the implied y-axis intercept of the SML is actually higher, while the slope of the SML is actually flatter than what is predicted by the traditional CAPM. The implication of these findings is that cost of equity estimates derived from the traditional CAPM will tend to underestimate the investor-required rate of return for lower beta stocks, including gas utility stocks, absent an adjustment to the traditional model.

Q. Is the CAPM commonly used to estimate the cost of equity, and does it influence the return expectations of investors?

A1. A. Yes, the CAPM is a widely referenced method for estimating the cost of equity among investment professionals, academics, and corporate finance departments and, therefore, influences the return expectations of investors.

According to the *Duff & Phelps Valuation Handbook*:

The CAPM has served as the foundation for pricing risk for nearly fifty years. Financial theorists generally have favored using the CAPM as the preferred method to estimate the cost of equity capital and the CAPM has become the most widely used method for estimating the cost of equity capital.²²

Further evidence of the CAPM’s popularity as a cost of equity analytical model is found in *Corporate Finance: A Focused Approach*, where Ehrhardt and Brigham state:

Recent surveys found that the CAPM approach is by far the most widely used method. Although most firms use more than one method, almost 74% of respondents in one survey, and 85% in the

²² 2016 *Valuation Yearbook* (Duff & Phelps, John Wiley & Sons) at 2-11.

1 other, used the CAPM.²³

2 Considering the widespread acceptance of the CAPM in both investment
3 management and academic settings, there can be no doubt that the CAPM exerts
4 significant influence over the return expectations of investors.

5 **Q. In structuring your CAPM analysis, what approach did you take in**
6 **estimating the market risk premium expectations of investors?**

7 A. To ensure a thorough and comprehensive evaluation of the risk premium
8 expectations of investors, I have completed market risk premium analyses on both
9 a prospective basis and on a historical basis. With regard to my prospective
10 analysis, I have evaluated forward-looking indicators of the market return
11 expectations of investors, along with time-horizon matched forecasts of the risk-
12 free rate of return. As for my historical analysis, I have relied upon the widely
13 referenced historical returns data reported in the *Kroll Cost of Capital Navigator*
14 for the 98-year period between 1926 and 2023.

15 **Q. What approach did you take in estimating the prospective market**
16 **return expectations of investors?**

17 A. To estimate the prospective market return expectations of investors, or “R_M,” I
18 have completed forward-looking DCF analyses for both the S&P 500 Index and the
19 Value Line 1,700 stock universe. The results of these DCF analyses, which have
20 been consistently applied to the Gas LDC Group, Combination Utility Group and
21 Non-Regulated Group, are presented on page 1 of Exhibit VVR-11. These results

²³ Michael Ehrhardt and Eugene Brigham, *Corporate Finance: A Focused Approach*, (South-Western Cengage Learning, 2008) at 303.

are also summarized as follows:

DCF Estimate of Market Return for the S&P 500 Index

$$1.43\% (D/P) + 10.83\% (g) = 12.26\% (K) \text{ or } (R_M)$$

Where: D/P = expected dividend yield over the next 12 months;
g = long-term earnings growth rate estimate;
R_M = expected return of the market portfolio.

The DCF results for the Value Line 1,700 stock universe are summarized as follows:

DCF Estimate of Market Return for the Value Line 1,700 Stock Universe

$$2.01\% (D/P) + 8.70\% (g) = 10.71\% (K) \text{ or } (R_M)$$

Based upon the results of the above DCF analyses for the S&P 500 Index and the Value Line 1,700 stock universe, an 11.48 percent $((12.26\% + 10.71\%) / 2 = 11.48\%)$ prospective market rate of return is indicated, which I have applied to each of the respective proxy groups.

Q. What approach did you take in estimating the prospective risk-free rate of return expectations of investors?

A. When discussing appropriate proxies for the risk-free rate of return in *Modern Regulatory Finance*, a widely referenced authoritative guide on utility cost of capital matters, Morin observes:

....investors price securities on the basis of long-term expectations, including interest rates. Cost of capital models are prospective (i.e., forward-looking) in nature and must take into account current market expectations for the future because investors price securities on the basis of long-term expectations, including interest rates. As a

1 result, in order to produce a meaningful estimate of investors'
2 required rate of return, the CAPM must be applied using data that
3 reflects the expectations of actual investors in the market. While
4 investors examine history as a guide to the future, it is the
5 expectations of future events that influence security values and the
6 cost of capital.

7

8 The empirical evidence demonstrates that stock prices do indeed
9 reflect prospective financial input data. Moreover, forecasted
10 interest rates are more relevant than current spot rates since in a
11 regulatory setting rates are being set for the future. In the same way
12 that one relies on forecast growth rates in DCF analyses as we shall
13 see in subsequent chapters, one should rely on interest rate forecasts
14 as proxies for the risk-free rate in the CAPM analysis²⁴

15 It is further noteworthy that the use of interest rate forecasts appropriately
16 synchronizes the time horizon of the expected risk-free rate of return with the
17 prospective market return I have employed within my analysis.

18 In selecting the appropriate “risk-free” security to evaluate, it should be noted that,
19 despite S&P’s 2011 downgrade of the long-term sovereign debt rating of the United
20 States, U.S. Treasury securities remain the closest thing to a risk-free financial
21 asset, largely due to the U.S. government’s taxing authority and ability to create
22 new currency. From a duration or tenor standpoint, 30-year Treasury Bonds most
23 closely parallel the investment characteristics of common stock, since both are
24 considered long-term, if not permanent, capital. Furthermore, in the absence of
25 market anomalies, 30-year Treasury yields, like common stocks, reflect the long-
26 term inflation expectations of investors, and are subject to less volatility than
27 shorter-dated Treasury securities.

²⁴ Roger A. Morin, *Modern Regulatory Finance* (PUR Books LLC, 2021) at 171-172.

1 As noted earlier, during the fourth-quarter of 2024, long-term interest rates,
2 including the 30-year Treasury bond yield, increased markedly. This has been
3 widely-attributed to the higher level of uncertainty in the U.S. capital markets
4 surrounding the potential effects of fiscal and other governmental policy changes
5 which are expected to be implemented by the Trump Administration. These
6 concerns center upon the potential inflationary impacts of various policy initiatives
7 that President Trump committed to implementing on the campaign trail, including
8 potential increased tariffs on U.S. trading partners, federal income tax policy
9 changes which could potentially have the effect of increasing the federal deficit, as
10 well as a number of immigration reforms. As a result, long-term interest rates have
11 trended markedly upward since October 2024. In turn, this has had the effect of
12 rendering the most recent long-term interest rate forecasts disseminated by
13 economists as largely outdated.

14 For the foregoing reasons, my risk-free rate of return assumption is based upon a
15 composite value which considers both: (1) the implied forward rates for the 30-
16 year U.S. Treasury bond as indicated by the debt capital markets, and (2) the recent
17 actual average 30-year Treasury bond yield for the fourth-quarter of 2024. More
18 specifically, I relied upon a recent average of the implied forward rate for the 30-
19 year Treasury bond over the 2025-2029 forecast period, which is 4.81 percent,²⁵
20 and the Q4, 2024 actual average yield for the 30-year Treasury bond, which is 4.50
21 percent. By placing an equal weighting on each of these values, I determined that

²⁵ Source: Bloomberg Finance L.P.

1 a reasonable estimate of the risk-free rate of return for purposes of my CAPM
2 analysis is 4.65 percent.

3 **Q. What prospective market risk premium is indicated by your analysis?**

4 A. Based upon a prospectively determined market rate of return of 11.48 percent and
5 a risk-free rate of return of 4.65 percent, a prospective market risk premium of
6 6.83 percent is indicated ($11.48\% - 4.65\% = 6.83\%$).

7 **Q. What average historical market risk premium is indicated by your**
8 **analysis?**

9 A. Based upon historical returns data reported by the *Kroll Cost of Capital*
10 *Navigator*, for the 98-year period between 1926-2023 a 7.17 percent historical
11 market risk premium is indicated. This figure is derived from the 12.04 percent
12 arithmetic average of total returns for large company stocks (S&P 500) for the
13 period between 1926-2023, and the 4.87 percent arithmetic average income return
14 on long-term government bonds for the same period ($12.04\% - 4.87\% = 7.17\%$).

15 **Q. Based upon your informed judgment, what level of market risk**
16 **premium have you applied to your CAPM analysis?**

17 A. As previously stated, to ensure a thorough and comprehensive evaluation of the
18 risk premium expectations of investors, I have conducted market risk premium
19 analyses on both a prospective basis and a historical basis. Although the historical
20 average market risk premium provides a useful point of reference for the analyst,
21 it should not be assumed that market risk premiums have been constant over time.
22 In fact, multiple empirical studies have demonstrated that not only do market risk
23 premiums fluctuate over time, but that they generally bear an inverse relationship

1 with long-term interest rates.²⁶ For these reasons, in deriving my overall estimate
2 of the market risk premium for purposes of my CAPM analysis, I have applied an
3 equal weighting to the 6.83 percent prospective market risk premium estimate that
4 I developed and the 7.17 percent historical average market risk premium reported
5 by the *Kroll Cost of Capital Navigator*. Placing an equal weighting on these two
6 values yields an overall indicated market risk premium of 7.00 percent.

7 **Q. Which beta values did you reference in your CAPM analysis?**

8 A. I referenced the published betas from the Value Line Investment Survey, a widely-
9 referenced source of beta values in utility regulatory proceedings. The average
10 betas reported by Value Line for the Gas LDC Group, Combination Utility Group
11 and Non-Regulated Group are 0.91, 0.92, and 0.91, respectively.

12 **Q. When applying the CAPM, what other types of adjustments are**
13 **required to fully reflect the return expectations of investors?**

14 A. Multiple academic studies have advocated the use of a size-premium adjustment
15 to the traditional CAPM.²⁷ These studies have revealed that small capitalization
16 stocks have historically earned returns that are materially higher than the returns
17 predicted by the CAPM. Indeed, the empirical research strongly suggests that beta,

²⁶ Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return", *Financial Management* (Spring 1986), at 58-67; Robert S. Harris and F. Marston, "Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts," *Financial Management*, 21 (Summer 1992), at 63-70; 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*, 24 (Autumn 1995), at 89-95; and Roger A. Morin, *New Regulatory Finance* (Public Utility Reports, Inc., 2006) at 129, 132 (citing Roger A. Morin, *Prepared Testimony on Fair Rate of Return on Equity for Hydro-Quebec* (Utility Research International, 2005)).

²⁷ See, Michael Annin, "Equity and the Small-Stock Effect," *Public Utilities Fortnightly*, October 15, 1995, 42-43; and, Eugene F. Fama and Kenneth R. French, "The Cross-Section of Expected Stock Returns," *The Journal of Finance*, 48 (June 1992), at 427-465.

1 or systematic risk alone, does not fully explain the higher relative returns earned
2 by small capitalization stocks. The 2023 SBBI Yearbook explains the size
3 phenomenon as follows:

4 One of the most remarkable discoveries of modern finance is the
5 finding of a relationship between company size and return, generally
6 referred to as the “size effect”. The size effect is based on the
7 empirical observation that companies of smaller size tend to have
8 higher returns than do larger companies.

9

10 The company size phenomenon is remarkable in several ways. First,
11 the greater risk of small-cap stocks does not, in the context of the
12 capital asset pricing model, fully account for their higher returns over
13 the long term. In the capital asset pricing model (CAPM) only
14 systematic, or beta risk, is rewarded; small-cap stock returns have
15 exceeded those implied by their betas.

16

17 The increased risk faced by investors in small stocks is quite real²⁸.

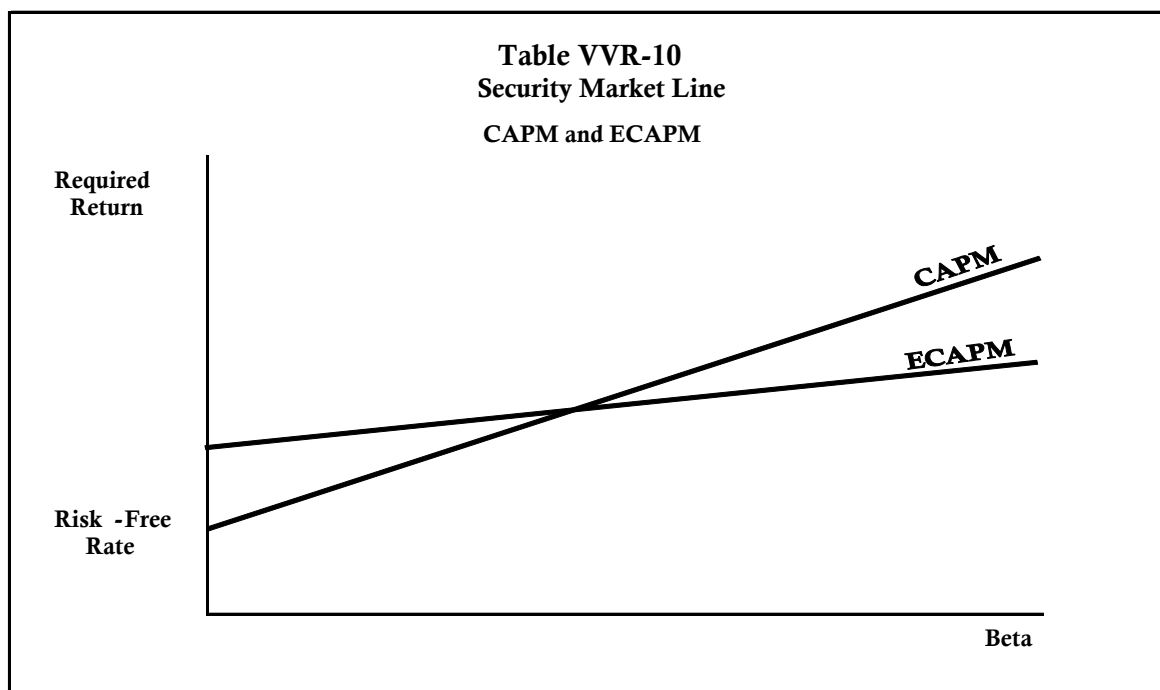
18
19 Therefore, to correct for the inherent deficiencies of the CAPM relative to smaller
20 capitalization stocks, the *Kroll Cost of Capital Navigator* reports size premiums,
21 which can be used in conjunction with the CAPM to more accurately estimate the
22 return expectations of investors relative to small and mid-capitalization stocks.
23 Based upon an average market capitalization of \$9.1 billion, the Gas LDC Group
24 would be classified as a Decile 3 portfolio and assigned a size premium of 0.61
25 percent. Based on an average market capitalization of \$19.4 billion, the
26 Combination Utility Group would be classified as a Decile 2 portfolio, and assigned
27 an average size premium of 0.46 percent. Lastly, based upon an average market
28 capitalization of \$136.1 billion, the Non-Regulated Group would be classified as a

²⁸ 2023 SBBI Yearbook, (Kroll LLC), at 143, 145 and 147.

large-cap, Decile 1 Portfolio, and assigned a size premium of *negative* -0.06 percent. In the absence of these size premium adjustments, the results indicated by the traditional CAPM for the Gas LDC Group and Combination Utility Group would *understate* the return expectations of investors, while with respect to the Non-Regulated Group, the traditional CAPM would have the tendency to *overstate* the return expectations of investors.

Q. Have you considered any other variants of the CAPM?

A. Yes. I have also considered the ECAPM within my evaluation. The ECAPM model is based upon extensive empirical evidence that the risk-return relationship between beta and stock returns, as graphically depicted by the Security Market Line reflected in Table VVR-10 below, is actually flatter than what is predicted by the traditional CAPM.



1 In a 1989 empirical study conducted by Morin, a simplified version of the ECAPM
2 was derived and is expressed as follows:²⁹

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

4 In essence, the ECAPM places a 25 percent weighting on the overall market risk
5 premium and a 75 percent weighting on the company specific, beta-adjusted risk
6 premium. The use of the same or similar forms of the ECAPM has been recognized
7 by state public service commissions, including the Montana Public Service
8 Commission, the New York Public Service Commission and the Regulatory
9 Commission of Alaska. The results of my ECAPM analysis for the Gas LDC Group,
10 Combination Utility Group and Non-Regulated Group are presented within pages
11 2, 3 and 4 of Exhibit VVR-11, respectively, and are also summarized in Table VVR-
12 11 below.

13 **Q. What were the results of your application of the CAPM, including the**
14 **variants of the model you evaluated?**

15 A. A detailed presentation of the results of my CAPM analysis for the Gas LDC Group,
16 Combination Utility Group and Non-Regulated Group is presented in Exhibit
17 VVR-11, and is also summarized in Table VVR-11 below. Although substantial
18 empirical evidence supports the use of both the CAPM with size adjustments and
19 the ECAPM, I have incorporated all three model variants into my evaluation,
20 including the traditional CAPM, in determining the CAPM-indicated cost of equity

²⁹ Roger A. Morin, *Modern Regulatory Finance* (PUR Books LLC, 2021), at 220-221.

for each of the respective proxy groups.

Table VVR-11 CAPM Results by Model Variant			
Model Variant	Gas LDC Group	Comb. Utility Group	Non- Reg. Group
Traditional CAPM	11.02%	11.09%	11.02%
+ Flotation adjustment	0.03%	0.03%	0.03%
Traditional CAPM	11.05%	11.12%	11.05%
CAPM (with size adj.)	11.63%	11.55%	10.96%
+ Flotation adjustment	0.03%	0.03%	0.03%
CAPM (with size adj.)	11.66%	11.58%	10.99%
Empirical CAPM	11.18%	11.23%	11.18%
+ Flotation adjustment	0.03%	0.03%	0.03%
Empirical CAPM	11.21%	11.26%	11.21%

These results, which incorporate the appropriate flotation cost adjustment, indicate a CAPM-derived cost of equity having a central tendency of around 11.30 percent for the Gas LDC Group, 11.32 percent for the Combination Utility Group, and 11.08 percent for the Non-Regulated Group.

D. Risk Premium Method (“RPM”) Analysis

Q. Please provide an overview of the RPM and the theoretical basis for using it to estimate a utility’s cost of equity.

A. The RPM is based upon the fundamental premise that a company’s cost of common equity is greater than its prospective cost of debt, due to the additional risks associated with investing in common stocks. The most important of these risks is residual claim risk, which arises due to the subordinated position of common stockholders relative to bondholders and preferred stockholders. In essence, common shareholders stand “last in line” with respect to the distribution of a company’s earnings, since common stock dividends are paid only after contractually required debt service payments and discretionary preferred dividend payments have been made. The same priority of claims also applies to asset-sale proceeds in the event of a bankruptcy liquidation scenario, where common shareholders typically only recover a small fraction, if any, of their original investment. As compensation for bearing these additional risks, common stock investors demand an equity risk premium over and above a company’s cost of debt. Considering that the equity risk premium is a forward-looking concept, it must be estimated on the basis of investor expectations and cannot be directly observed. Once the expected risk premium has been estimated, it can be added to the company’s prospective cost of debt to estimate the cost of common equity, as follows:

$$K = C_D + P_R$$

Where: K = expected cost of common equity;
 C_D = company's prospective cost of debt;
 P_R = expected equity risk premium.

Q. Is the RPM commonly used to estimate the cost of equity and does it influence the return expectations of investors?

A. Yes, the RPM is a widely-referenced cost of equity model among investors, analysts and academics, and therefore influences investor return expectations. Evidence of the popularity of the RPM is found in *Corporate Finance: A Focused Approach*, where Ehrhardt and Brigham state that "three methods typically are used" in estimating the cost of common equity, one of which is the RPM³⁰.

Q. How did you approach your RPM analysis?

A. In applying the RPM to the three respective proxy groups, I employed a virtually identical approach, as only a few minor adjustments were required for the Non-Regulated Group. In essence, my approach involved estimating the prospective long-term bond yields (C_D) for each of the proxy groups based upon their average credit ratings, and then estimating the appropriate equity risk premium (P_R) for each of the three groups. Once these two components were derived for each of the proxy groups, they were simply added together to arrive at the RPM-indicated cost of equity. My comprehensive RPM analysis is presented within Exhibit VVR-12, which is comprised of 10 pages. Summary results for the Gas LDC Group, Combination Utility Group and the Non-Regulated Group are presented on pages

³⁰ M. Ehrhardt and E. Brigham, *Corporate Finance: A Focused Approach* (South-Western Cengage Learning, 2008), at 294.

1 1, 7 and 9 of Exhibit VVR-12, respectively. A detailed discussion of the RPM results
2 for the Gas LDC Group is presented herein. Quantitative results for the
3 Combination Utility Group and Non-Regulated Group are presented within pages
4 7-10 of Exhibit VVR-12.

5 **Q. How did you derive the 6.06 percent prospective bond yield for the Gas**
6 **LDC Group?**

7 A. The bond yields referenced in the RPM must appropriately reflect the forward-
8 looking return expectations of investors. For this reason, in determining the “CD”
9 component of the RPM equation, I have employed a forward-looking long-term
10 bond yield for the Gas LDC Group based upon the Group’s average long-term credit
11 ratings of “BBB+” from S&P, and “Baa1” from Moody’s. As reflected on page 1 of
12 Exhibit VVR-12, this was accomplished by first evaluating forecasted bond yields
13 for Aaa rated corporate bonds, and then making the necessary credit spread
14 adjustments to reflect the higher level of default risk associated with “BBB+ /Baa1”
15 rated utility bonds.

16 As reflected on pages 1 and 2 of Exhibit VVR-12, the estimated composite
17 “Aaa” rated corporate bond yield for the 2025-2029 period is 5.41 percent. This
18 composite yield was determined on the basis of applying an equal weighting
19 between: (1) the implied forward rates for “Aaa” rated corporate bonds for the
20 2025-2029 period as indicated by the debt capital markets, and (2) the recent
21 actual average “Aaa” rated corporate bond yield for the fourth-quarter of 2024.

22 An upward adjustment of 0.50 percent was required to reflect the credit
23 spread differential between Aaa rated corporate bonds and A rated utility bonds,

1 both of which reflect Moody's generic ratings categories. A further upward
2 adjustment of 0.15 percent was also required to reflect the credit spread differential
3 between the generic rating category of "A" and the more precise "BBB+" rating
4 from S&P and "Baa1" rating from Moody's. Additional information supporting
5 both of these credit spread adjustments can be found within pages 1 and 3 of
6 Exhibit VVR-12. The prospective bond yield for the Gas LDC Group was derived
7 by adding both of the aforementioned credit spread adjustments to the prospective
8 "Aaa" rated corporate bond yield, which resulted in a 6.06 percent³¹ prospective
9 bond yield.

10 **Q. What general approach have you taken in estimating the expected**
11 **equity risk premium for the Gas LDC Group?**

12 A. Consistent with established practices, I have conducted equity risk premium
13 analyses using both the total market approach and the public utility index
14 approach. The total market approach is considered an "indirect" approach, since
15 an equity risk premium is initially estimated for the overall market portfolio, and
16 is subsequently adjusted to reflect the specific risk profile of the applicable proxy
17 group. Within the framework of the total market approach, I have conducted
18 separate risk premium analyses on both a historical basis and a prospective basis,
19 as reflected on page 4 of Exhibit VVR-12. In contrast, the public utility index
20 approach is considered a "direct" approach, since the expected equity risk
21 premium is estimated by comparing average historical holding period returns for

³¹ Subject to rounding differences.

1 the S&P 500 Utilities Index to historical yields on long-term public utility bonds,
2 without the need for any further risk adjustments. The results of my public utility
3 index approach analysis are presented on page 5 of Exhibit VVR-12.

4 **Q. In applying the total market approach to the Gas LDC Group, how did**
5 **you arrive at the indicated equity risk premium of 5.44 percent?**

6 A. As previously mentioned, in applying the total market approach, I conducted both
7 historical and prospective risk premium analyses, each of which brings different
8 strengths and perspectives into the evaluation process.

9 1. Historical Risk Premium Analysis

10 To facilitate a historical risk premium analysis under the total market
11 approach, I have relied upon the historical holding period returns information for
12 both large company stocks (S&P 500 Index) and for high-grade, long-term
13 corporate bonds. When the average historical risk premium is used as a proxy for
14 the prospective risk premium, its predictive value is enhanced when the longest
15 possible historical period is evaluated. Accordingly, I have utilized the average
16 historical holding period returns for the 98-year period between 1926-2023 as
17 reported by the *Kroll Cost of Capital Navigator*. The arbitrary use of shorter time
18 periods would subject the risk premium analysis to greater potential volatility from
19 short-term market trends and/or aberrations, which would not reflect the long-
20 term expectations of investors. Moreover, use of the longest possible historical
21 period for which data is available will incorporate a greater number of business
22 and interest rate cycles into the analysis, further enhancing its predictive value.

1 Indeed, Morin provides support for this approach in *Modern Regulatory Finance*
2 where he maintains:

3 The historical risk premium approach assumes that the average
4 realized return is an appropriate surrogate for expected return, or, in
5 other words, that investor expectations are realized. However,
6 realized returns can be substantially different from prospective
7 returns anticipated by investors, especially when measured over
8 short time periods. Therefore, an historical risk premium study
9 should consider the longest possible period for which data are
10 available. . . . Clearly, the accuracy of the realized risk premium as
11 an estimator of the prospective risk premium is enhanced by
12 increasing the number of years used to estimate it.³²

13
14 Therefore, based upon this approach, a 5.89 percent historical equity risk premium
15 is indicated using the total market approach. As shown on page 4 of Exhibit VVR-
16 12, this result is based upon the arithmetic average annual return of 12.04 percent
17 for large company stocks (S&P 500 Index), and the arithmetic average annual
18 return of 6.15 percent for high-grade, long-term corporate bonds. Use of the
19 arithmetic average risk premium is appropriate since it better reflects the forward-
20 looking risk premium expectations of investors and the potential variability of
21 expected returns. In contrast, the geometric mean is more suitable for reporting
22 past investment performance, since it reflects a consistently compounded or
23 “smoothed” rate of growth over a given historical period.

24 Further support for using the arithmetic average equity risk premium is also
25 found in the *SBBI Yearbook*, a widely-cited investment guide, which states:

26 The arithmetic average equity risk premium can be demonstrated to
27 be most appropriate when discounting future cash flows. For use as
28 the expected equity risk premium in either the CAPM or the building-

³² Roger A. Morin *Modern Regulatory Finance* (PUR Books LLC, 2021), at 129-130.

1 block approach, the arithmetic mean or the simple difference of the
2 arithmetic means of stock market returns and riskless rates is the
3 relevant number. This is because both the CAPM and the building-
4 block approach are additive models, in which the cost of capital is the
5 sum of its parts. The geometric average is more appropriate for
6 reporting past performance because it represents the compound
7 average return³³.

8 2. Prospective Risk Premium Analysis

9 A prospective risk premium analysis is also required to fully capture the forward-
10 looking return expectations of investors. Indeed, it is often maintained that
11 prospective risk premiums bear the greatest relevance to the cost of equity
12 estimation process, since they incorporate both historical trends and changes
13 expected to occur in the future. To facilitate a prospective risk premium analysis
14 using the total market approach, it was necessary to estimate both the prospective
15 market return expectations of investors and the prospective corporate bond yield
16 on a time horizon matched basis. As previously referenced in the CAPM section of
17 my testimony, and as illustrated on page 1 of Exhibit VVR-11, I have estimated the
18 prospective market return expectations of investors by completing DCF analyses
19 for both the S&P 500 Index and the Value Line 1,700 stock universe. The results
20 of these analyses are as follows:

21 DCF Estimate of Market Return for the S&P 500 Index

$$22 \quad 1.43\% (D/P) + 10.83\% (g) = 12.26\% (K) \text{ or } (R_M)$$

24 DCF Estimate of Market Return for the Value Line 1,700 Stock Universe

³³ 2017 SBBI Yearbook (Duff & Phelps, John Wiley & Sons, Inc.), at 10-22.

1 $2.01\% (D/P) + 8.70\% (g) = 10.71\% (K) \text{ or } (R_M)$

2 Based upon these DCF results, an 11.48 percent $((12.26\% + 10.71\%)/2 = 11.48\%)$
3 prospective market return is indicated. As a proxy for the prospective corporate
4 bond yield, I have relied upon the 5.41 percent composite “Aaa” rated corporate
5 bond yield as presented in pages 1-2 of this Exhibit. Based upon these values, a
6 6.07 percent prospective equity risk premium is indicated under the total market
7 approach $(11.48\% - 5.41\% = 6.07\%)$.

8 3. Total Market Equity Risk Premium and Risk Adjustment

9 To ensure a balanced approach in assessing the risk premium expectations
10 of investors, I have placed equal emphasis on the historical risk premium and
11 prospective risk premium results indicated above. Using this balanced approach,
12 a 5.98 percent total market risk premium is indicated $((5.89 \text{ percent} + 6.07$
13 $\text{percent})/2 = 5.98 \text{ percent})$.³⁴ Considering that this result must be adjusted to
14 recognize the risk differential between the overall market index and the Gas LDC
15 Group, I have applied a beta value of 0.91 to the indicated market risk premium to
16 derive a risk premium which is applicable to the Gas LDC Group. Therefore, as
17 reflected on page 4 of Exhibit VVR-12, the indicated equity risk premium for the
18 Gas LDC Group was determined to be 5.44 percent $(5.98 \text{ percent} \times 0.91 = 5.44$
19 $\text{percent})$.

20 **Q. In applying the public utility index approach to the Gas LDC Group,**

³⁴ Subject to rounding differences.

how did you arrive at the indicated equity risk premium of 4.85 percent?

A. The results of my public utility index approach analysis are presented on page 5 of Exhibit VVR-12. As a proxy for the total return expectations of investors relative to utility stocks, I have evaluated both the average historical holding period returns for the S&P 500 Utilities Index, as well as the currently-implied equity risk premium for the same index. With regard to the average historical holding period returns for the 1926-2024 period, the average annual total return for this index was 10.75 percent. During this same period, the average annual yield for long-term utility bonds bearing an “A” rating from Moody’s was 6.22 percent. Historical yields on “A” rated utility bonds were selected for evaluation since “A” rated bonds represent the mid-point credit rating among the historical utility bond yields that have been reported by Moody’s and Mergent (historical yields on three credit ratings have been reported: “Aa,” “A” and “Baa”). A detailed breakdown of these historical returns is presented on page 6 of Exhibit VVR-12. Based upon the foregoing historical returns, a 4.54 percent equity risk premium is indicated for the Gas LDC Group (10.75 percent - 6.22 percent = 4.54 percent).

As further detailed in the bottom section of page 5 of Exhibit VVR-12, I have also evaluated the currently implied equity risk premium in the prevailing market environment, by conducting an analysis of the expected equity return for the S&P Utilities Index, which yielded an expected return of 10.63 percent. I then compared the recent yields on “A” rated utility bonds (5.46%) to the expected equity return, which yielded a currently-implied equity risk premium of 5.17

1 percent (10.63 percent - 5.46 percent=5.17 percent).³⁵ Finally, to ensure a
2 balanced estimate of the equity risk premium under the Public Utility Index
3 Approach, I referenced the average of the equity risk premium estimates derived
4 under the historical approach and the currently-implied approach, which yielded
5 an indicated equity risk premium of 4.85 percent $((4.54 \text{ percent} + 5.17 \text{ percent}) / 2 =$
6 4.85 percent).

7 **Q. Based upon your RPM analysis using both the total market approach**
8 **and the public utility index approach, what level of equity risk**
9 **premium and cost of equity are indicated for the Gas LDC Group?**

10 A. To ensure a balanced analysis, I have placed equal emphasis on the total market
11 approach and the public utility index approach and have concluded that 5.15
12 percent is a reasonable estimate of the expected equity risk premium for the Gas
13 LDC Group. Based upon an expected risk premium of 5.15 percent, and a 6.06
14 percent prospective long-term bond yield for the Gas LDC Group, I have also
15 concluded that the unadjusted RPM-indicated cost of equity for the Gas LDC
16 Group is 11.20 percent $(5.15 \text{ percent} + 6.06 \text{ percent} = 11.20 \text{ percent})$ ³⁶. Consistent
17 with the other market-based analytical models, to this result I added the required
18 flotation cost adjustment of 0.03 percent, which yielded an adjusted RPM-
19 indicated cost of equity of 11.23 percent for the Gas LDC Group.

20 **Q. Under the RPM, what cost of equity was indicated for the Combination**

³⁵ Subject to rounding differences.

³⁶ Subject to rounding differences.

Utility Group and the Non-Regulated Group?

A. As reflected on page 7 of Exhibit VVR-12, the unadjusted RPM-indicated cost of equity for the Combination Utility Group was determined to be 11.20 percent. Consistent with the other market-based analytical models, I added the required 0.03 percent flotation cost adjustment for the Combination Group to this result, which yielded an adjusted RPM-indicated cost of equity of 11.23 percent for the Combination Utility Group.

Lastly, as reflected on page 9 of Exhibit VVR-12, the unadjusted RPM-indicated cost of equity for the Non-Regulated Group was determined to be 11.35 percent. Consistent with the other market-based analytical models, I added the required 0.03 percent flotation cost adjustment to this result, which yielded an adjusted RPM-indicated cost of equity of 11.38 percent for the Non-Regulated Group.

The results of my RPM evaluation are summarized in Table VVR-12 below.

Table VVR-12 Risk Premium Method Results			
Model Variant	Gas LDC Group	Comb. Utility Group	Non-Reg. Group
Risk Prem. Method	11.20%	11.20%	11.35%
+ Flotation cost adjust.	0.03%	0.03%	0.03%
Risk Premium Method	11.23%	11.23%	11.38%

VII. RECAP OF MODEL RESULTS AND RECOMMENDATIONS

Q. Can you please summarize the results of the various cost of equity analytical models you evaluated, as well as your proposed ROE recommendation in the instant proceeding?

A. Yes, I present Table VVR-1 below, which was also presented earlier in my testimony, and which summarize the results of my cost of equity evaluation and ROE recommendations.

Table VVR-1 Indicated Cost of Equity for the Proxy Groups			
Method/Model	Gas LDC Group	Comb. Utility Group	Non-Reg. Group
DCF	10.97%	10.57%	11.27%
Traditional CAPM	11.05%	11.12%	11.05%
CAPM (w/size adj.)	11.66%	11.58%	10.99%
ECAPM	11.21%	11.26%	11.21%
Risk Premium	11.23%	11.23%	11.38%

An analysis of the results shown in Table VVR-1 above yielded measures of central tendency for each of the analytical methods employed, which I have presented again in Table VVR-2 and Table VVR-3 below.

Table VVR-2 Cost of Equity Estimates for CPA Measures of Central Tendency for the Core Proxy Group – Gas LDC Group	
Median DCF Result	10.97%
Average DCF Result	10.97%
Median CAPM Result	11.21%
Average CAPM Result	11.31%
Median RPM Result	11.23%
Average RPM Result	11.23%

Table VVR-3 Cost of Equity Estimates for CPA Measures of Central Tendency for All Three Proxy Groups	
Median DCF Result	10.97%
Average DCF Result	10.94%
Median CAPM Result	11.21%
Average CAPM Result	11.24%
Median RPM Result	11.23%
Average RPM Result	11.28%

Based upon the above measures of central tendency, I have concluded that Columbia's cost of equity is presently in the range of 10.85 - 11.35 percent, and that point estimate in the middle of this range, or 11.10 percent, fairly reflects the Company's cost of equity in the current market environment. Also, as noted earlier, the Company has proposed a 0.25 percent upward adjustment to my point estimate of the cost of equity in recognition of the Company's strong record of

1 management effectiveness as discussed in the Direct Testimony of Columbia
2 witness Paloney. After incorporating this proposed adjustment, it is my
3 recommendation that the Commission should adopt a cost of equity of 11.35
4 percent in the determination of a fair rate of return for the Company in this
5 proceeding.

6 **Q. Does this conclude your Prepared Direct Testimony?**

7 A. Yes, it does.

8

Appendix A

DCF Analysis - Detailed Discussion

1. Determination of the Dividend Yield Component

Since the DCF model recognizes that investors value securities on the basis of prospective cash flows, it is essential that the analyst determine the amount of dividend payments (D_1) which are expected to be received over the next twelve months. Utilizing the current dividend amount (D_0) would not be appropriate under DCF principles, since current dividends are not forward-looking and could potentially underestimate the cost of equity. For this reason, estimates of dividends to be paid over the next twelve months by each company comprising the Gas LDC Group, Combination Utility Group and Non-Regulated Group were obtained from the Value Line Summary and Index, and serve as the expected dividend payment (D_1) within these two respective DCF analyses.

In selecting the appropriate stock price (P_0) to utilize in calculating the dividend yield, it is important to remember that under the iterative market valuation process, price equilibrium only occurs when investors have realized their expected rate of return, or “K.” In other words, the current stock price (P_0) has embedded within it the current forward-looking return expectations of investors, although the latter cannot be directly observed. Therefore, to properly estimate the expected cost of equity, it is essential that the current stock price (P_0) be used when calculating the dividend yield component, since the “P” and “K” components of the model are simultaneously determined upon reaching equilibrium, and thus have a time dependency on one another. Consistent with the semi-strong version of the Efficient Market Hypothesis, use of the current stock price is appropriate, since it

1 incorporates all relevant publicly-available information and thus captures the current
2 forward-looking growth expectations of investors.

3 In contrast, using an average of stock prices over some historical period, such as six to
4 twelve months, would reflect outdated market information and investor growth
5 expectations, which would not be representative of current market conditions. Therefore,
6 such an approach would be inconsistent with the core tenets of the Efficient Market
7 Hypothesis. Moreover, using past averages of stock prices would also create a time period
8 mismatch among the components of the DCF model, since the dividend yield component
9 would be based upon past stock prices which reflect previous growth expectations, while
10 the growth component (“g”) of the model would reflect the current forward-looking
11 growth expectations of investors.

12 Notwithstanding these compelling arguments, simply referencing the most recent day’s
13 closing stock price can present a different challenge in the form of temporary price
14 aberrations, which may be attributable to volatile market conditions, the unanticipated
15 release of company information, or short-term supply and demand imbalances.
16 Therefore, with respect to the companies comprising the Gas LDC Group, Combination
17 Utility Group and Non-Regulated Group, I have defined the current stock price (P_0) as an
18 average closing stock price that is calculated on the basis of the composite average of the
19 30-day average, 60-day average and 90-day average stock prices. This approach places
20 the most emphasis on the 30-day average stock price, but also provides some weighting to
21 the 60-day average and 90-day average stock prices. More specifically, this approach
22 places a one-half weighting on the 30-day average stock price, a one-third weighting on
23 the 60-day average stock price, and a one-sixth weighting on the 90-day average stock
24 price. Taking this approach mitigates the effects of short-term price aberrations for the

1 companies comprising these three proxy groups, while still recognizing the basic tenets of
2 the Efficient Markets Hypothesis.

3 Finally, to determine the expected dividend yield for the companies comprising the Gas
4 LDC Group, Combination Utility Group and Non-Regulated Group, the expected dividend
5 (D_1) was simply divided by the current stock price (P_0) as defined above.

6 2. Growth Component – General Approach

7
8 There is no question that discerning the long-term growth expectations of investors is the
9 most difficult and controversial aspect of implementing the DCF constant growth model,
10 as it requires the analyst to get inside the “collective psyche” of a large universe of
11 investors. Considering that the DCF model is technically focused on the growth of
12 dividends into perpetuity, a reliable forecast of sequential dividend payments into the
13 distant future would provide an appropriate indication of investors’ long-term growth
14 expectations. However, dividend forecasts for multi-decade periods are simply not
15 available, so to implement the DCF model, the analyst must rely upon other available
16 indicators which are likely to influence the growth expectations of investors. As such, in
17 the initial stages of my DCF analysis, I evaluated a variety of historical and forward-
18 looking growth indicators, each of which could potentially influence investor expectations.

19 Recognizing that historical growth trends can influence the future growth expectations of
20 investors, rate of return analysts often consider historical trends when estimating the
21 growth component of the DCF model. In so doing, the presumption is that investors
22 extrapolate past growth patterns in forming their future expectations. In my judgment,
23 evaluating historical growth indicators is a reasonable first step in the DCF growth rate
24 evaluation process, particularly for companies with a history of stable performance.

1 Nevertheless, while historical growth trends clearly provide a valuable point of reference,
2 the analyst must guard against placing too much emphasis upon them, as they may no
3 longer reflect the current growth expectations of investors. Indeed, the growth
4 expectations of investors today may be very different from average growth rates realized
5 in the past due to structural changes within the utility industry, changes in operating costs
6 and expected profitability, and/or changes in general economic conditions. Also, it is often
7 argued that historical growth trends are already factored into forward-looking growth
8 projections, including analyst earnings forecasts, and that care should therefore be taken
9 to ensure that historical data is not inadvertently double-counted.

10 Lastly, when evaluating historical growth trends, the analyst generally finds that the strict
11 assumptions required under constant growth theory have not held true or been
12 maintained, as is often reflected in differing historical growth rates between DPS, EPS and
13 BVPS. Thus, while the analyst implicitly accepts the strict assumptions of the constant
14 growth model on a prospective basis, this is rarely the case in retrospect, which may call
15 into question the usefulness of historical indicators in deriving the constant growth rate
16 assumption.

17 Considering these multiple shortcomings, historical growth indicators should never be
18 relied upon exclusively and significant emphasis should also be placed on forward-looking
19 growth indicators. Therefore, consistent with accepted practices, I have evaluated both
20 historical and forward-looking growth indicators for several key variables, including EPS,
21 DPS, and BVPS. More specifically, with regard to historical growth rates, for each member
22 of the Gas LDC Group and Combination Utility Group, I have completed a traditional
23 analysis of the 5-year and 10-year average historical growth rates for EPS, DPS, and BVPS.
24 All 5-year and 10-year historical growth rate information was sourced from the Value Line

1 Investment Survey. The results of my historical growth rate analysis for EPS, DPS and
2 BVPS for the Gas LDC Group and Combination Utility Group are presented on page 5 of
3 Exhibit VVR-7 and Exhibit VVR-8, respectively.

4 With regard to projected growth rates, for each member of the Gas LDC Group and
5 Combination Utility Group, I have analyzed forward-looking projections for EPS, DPS,
6 and BVPS. Growth projections for each of these variables were derived from the Value
7 Line Investment Survey, which publishes 3-to-5 year growth rate projections. In addition,
8 EPS consensus estimate growth rates were sourced from S&P Global Market Intelligence
9 and Zacks, both of which disseminate 5-year earnings growth estimates. The results of my
10 projected growth rate analyses for EPS, DPS and BVPS for the Gas LDC Group and
11 Combination Utility Group are presented on pages 1 and 5 of Exhibit VVR-7 and Exhibit
12 VVR-8, respectively.

13 With regard to the nine companies comprising the Non-Regulated Group, I have focused
14 my analysis on projected growth rates for EPS, as well as historical EPS growth rates.
15 Growth projections for EPS were sourced from the Value Line Investment Survey, while
16 EPS consensus estimate growth rates were sourced from S&P Global Market Intelligence
17 and Zacks. Historical EPS growth rates were sourced from Value Line. With respect to
18 the Non-Regulated Group, the results of my projected growth rate analyses are presented
19 within page 1 of Exhibit VVR-9, while the results of my historical EPS growth rate analysis
20 are presented on page 2 of Exhibit VVR-9.

21

22

3. Growth Component

Dividend Growth Forecasts vs. Earnings Growth Forecasts

Notwithstanding the fact that the DCF model is conceptually a dividend-based model, in practice there exists a fundamental challenge in attempting to reference dividend forecasts to estimate the growth expectations of investors. Simply stated, dividend forecasts are not widely-referenced by investors, and for this reason, they are only published by a limited number of information service providers. In contrast, earnings growth forecasts are widely-available from a variety of internet-based and print media sources. As I will discuss later, earnings forecasts are widely-referenced by investors and are available to the general public from a variety of sources. It should also be noted that even Williams, who originally developed the long-form and constant growth versions of the DCF model, found “no contradiction” between his DCF formula which emphasized dividends, and the “common precept” that earnings constitute the source of value for stocks. Indeed, over the long-run, either valuation approach would be expected to produce the same end result. Lastly, Williams also recognized the challenges associated with developing long-term dividend forecasts, when he concluded in *The Theory of Investment Value*: “How to estimate the future dividends for use in our formula is, of course, the difficulty¹⁹”.

4. Growth Component

The Importance of Earnings Growth Forecasts

Among the various forms of growth estimates I evaluated, I place the greatest emphasis on the consensus earnings estimates of “sell-side” equity analysts, along with earnings forecasts published by the Value Line Investment Survey. Substantial academic research has demonstrated that equity analyst forecasts have a significant influence on the growth

¹ John Burr Williams, *The Theory of Investment Value* (Cambridge, MA, Harvard University Press, 1938) at 58.

1 expectations of investors. By way of background, sell-side analysts compile investment
2 research for the major brokerage firms and investment banks on behalf of their clients.
3 This research includes both earnings forecasts and buy/hold/sell recommendations,
4 which the analyst develops based upon a thorough analysis of the company's past
5 performance and future prospects, along with an element of informed judgment. Sell-side
6 analysts typically possess expert knowledge of the industry they cover, and are typically
7 well-versed in key matters affecting the company being evaluated, including recent
8 regulatory decisions, cost and profitability trends, and infrastructure investment
9 requirements. Substantial academic research has demonstrated that the earnings
10 forecasts of equity analysts heavily influence the long-term growth expectations, and
11 therefore investment decisions, of equity investors. For example, In "Using Analysts'
12 Growth Forecasts to Estimate Shareholder Required Rates of Return," Harris concludes:

13 ...a growing body of knowledge shows that analysts' earnings forecasts
14 are indeed reflected in stock prices.....Notions of shareholder required
15 rates of return and risk premia are based in theory on investors'
16 expectations about the future. Research has demonstrated the
17 usefulness of financial analysts' forecasts for such expectations².

18 Similarly, in "Investor Growth Expectations: Analysts vs. History," Vander Weide and
19 Carleton concluded:

20 [First] we found overwhelming evidence that the consensus analysts'
21 forecast of future growth is superior to historically oriented growth
22 measures in predicting the firm's stock price. ...Our results also are
23 consistent with the hypothesis that investors use analysts' forecasts,
24 rather than historically oriented growth calculations, in making stock
25 buy-and-sell decisions³.

² Robert S. Harris, "Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return," *Financial Management*, (Spring 1986), at 59, 66.

³ James H. Vander Weide and William T. Carleton, "Investor Growth Expectations: Analysts vs. History," *The Journal of Portfolio Management* (Spring 1988), at 4.

1 In *Modern Regulatory Finance*, Morin sums up the academic literature on this topic
2 very effectively where he states:

3 Because of the dominance of institutional investors and their influence
4 on individual investors, analysts' forecasts of long-run growth rates
5 provide a sound basis for estimating required returns. Financial
6 analysts exert a strong influence on the expectations of many investors
7 who do not possess the resources to make their own forecasts, that is,
8 they are the cause of "g".

9

10 Published studies in the academic literature demonstrate that growth
11 forecasts made by security analysts represent an appropriate source of
12 DCF growth rates, are reasonable indicators of investor expectations
13 and are more accurate than forecasts based on historical growth.
14 These studies show that investors rely on analysts' forecasts to a
15 greater extent than on historic data.⁴
16

17 Clearly then, a substantial amount of academic research supports the use of analyst
18 earnings forecasts as an appropriate proxy for the expected growth rate component of the
19 DCF constant growth model. For these reasons, I have given considerable weight to the
20 5-year consensus earnings estimates available from S&P Global Market Intelligence and
21 Zacks, along with Value Line's EPS growth forecasts, in deriving my estimates of long-
22 term investor growth expectations.

23
24 5. Growth Component – Market-Based Evidence
25 The Influence of Analyst Estimates on Investor Growth Expectations
26

27
28 Analyst earnings forecasts are widely available through a variety of sources and are
29 frequently referenced by both institutional and individual investors and the financial
30 press. Without question, a robust market exists for earnings estimates, which is driven by
31 strong investor demand for such information. Considering that there is a significant
32 monetary cost associated with producing these forecasts, investment firms would not

⁴ Roger A. Morin, *Modern Regulatory Finance* (PUR Books LLC, 2021), at 371, 373.

1 continue to produce them if they were not valued by investors. This is further
2 demonstrated by the ongoing success of the various information service providers who
3 summarize analyst earnings forecasts into “consensus estimates” for the benefit of
4 investors. These information service providers include S&P Global Market Intelligence,
5 Thomson Reuters, I/B/E/S, and FactSet, each of which are widely-referenced by
6 institutional investors.

7 Moreover, the availability of consensus estimates to the general public through freely-
8 accessible websites such as Zacks further demonstrates the pervasive influence that
9 analyst forecasts have on market expectations, including those of individual investors.
10 Lastly, it is important to note that, to date, investors have not demanded earnings forecasts
11 for periods extending beyond five years. If investors had expressed a desire for such
12 information, the robust information services marketplace would have certainly delivered
13 longer-term forecasts by now. This strongly suggests that investors are reasonably
14 confident that the 5-year earnings forecasts they presently utilize already provides a
15 reasonably reliable longer-term growth estimate.

16
17 6. Growth Component
18 Earnings Growth Rates Currently Projected by Equity Analysts
19
20

21 Forecasts of EPS growth and the corresponding cost of equity estimates for each member
22 of the Gas LDC Group, Combination Utility Group and Non-Regulated Group are
23 presented on page 1 of Exhibit VVR-7, Exhibit VVR-8, and Exhibit VVR-9, respectively.

Appendix B

DCF Estimates - Determination of “Outlier” Results

1. General Approach in Determining the “Low-End” Threshold for Outlier Results

While applying the DCF constant-growth model to the individual proxy group companies, I found both “low-end” and “high-end” outlier results which did not pass fundamental tests of economic logic. Therefore, to ensure logical and credible analytical results, I have eliminated unreasonably high and unreasonably low DCF estimates from my analysis, as further discussed herein.

It is a well-established financial principle that when the risk profile of a given investment increases, investors will demand a commensurately higher rate of return. This classic “risk-and-return” relationship explains why investors demand a higher return for investing in common stocks versus investing in corporate debt securities. Indeed, equity investors are not only compensated for the default risk inherent in fixed-income securities, but they must also be compensated for the residual claim risk they bear. Residual claim risk arises for two primary reasons. First, since common stock is the lowest ranking or most junior capital within a firm’s capital structure, common stock investors are always positioned “last in line” behind fixed income investors and preferred stockholders to recover their investment in the event of a financial distress scenario. Second, common stock investors are also in a subordinated position relative to periodic cash distributions, since common stock dividends can only be paid after contractually-required debt service payments and preferred dividend payments have been made. Considering their junior

1 position in the capital structure, common stock investors require additional compensation
2 for bearing this residual claim risk, through what is known as an equity risk premium.

3 However, in those circumstances where the equity risk premium offered does not provide
4 sufficient compensation for bearing the additional risks associated with common stocks,
5 investors will seek a superior risk-return tradeoff elsewhere by either investing in the
6 company's fixed-income securities, or in another company's common stock. Therefore,
7 consistent with the risk-and-return investment principle and fundamental tests of
8 economic logic, DCF estimates which are lower than, or only marginally higher than, yields
9 available on corporate debt securities have been eliminated from my analysis. This is
10 because investors cannot reasonably be expected to invest in common stocks if they are
11 unable to earn a minimally sufficient equity risk premium as compensation for the
12 additional risks they bear, vis-à-vis fixed income securities. Under these circumstances,
13 investors would clearly show a preference for either holding the company's fixed-income
14 securities or another company's stock, making it difficult for the company to attract new
15 equity capital.

16 2. Regulatory Precedents Establishing the Minimum Equity Risk
17 Premium for Setting the "Low-End" Outlier Threshold
18
19

20 In recent years, the FERC has compared DCF estimates to yields available on long-term
21 corporate bonds and has excluded proxy group companies whose DCF estimates did not
22 exceed a company's bond yield by a sufficient margin. In *Pioneer Transmission* (2009),
23 the FERC ruled that low-end ROEs falling within about 100 basis points of the cost of debt
24 should be excluded from cost of equity estimates. Specifically, in its Pioneer order, the
25 FERC stated:

1 the Commission will exclude from the proxy group companies whose
2 low-end ROE is within about 100 basis points above the cost of debt,
3 taking into account the extent to which the excluded low-end ROE's are
4 outliers from the low-end ROEs of other proxy group companies¹.

5 Previously, in Opinion 445, the Commission had determined that:

6 investors generally cannot be expected to purchase stock if debt,
7 which has less risk than stock, yields essentially the same return².

8 Furthermore, in *Southern California Edison*, the FERC reaffirmed its previous decisions
9 concerning the treatment of low-end outliers, by stating:

10 We find that, consistent with *Pioneer*, it is reasonable to exclude any
11 company whose low-end ROE fails to exceed the average bond yield by
12 about 100 basis points or more³.

13
14 Most recently, in *Opinion No. 569*, the FERC revised the methodology it employs in the
15 determination of both low-end and high-end outlier estimates of the cost of equity under
16 the DCF method. The FERC's revised low-end methodology no longer references a generic
17 100 basis point add-on to the cost of corporate debt, but instead now recognizes the
18 dynamic nature of the equity risk premium, which is dependent upon ever-changing
19 investor risk sentiments. The FERC will now reference Baa-rated corporate bond yields
20 as the corporate bond component of the low-end outlier equation, but will now determine
21 the minimally-required equity risk premium above the corporate bond yield by applying a
22 20 percent weighting factor to the market risk premium determined under the FERC's
23 CAPM analysis. The FERC explained the rationale for these changes as follows:

24 We will adjust the low-end outlier test to include a risk premium instead of
25 the generic 100 basis points proposed in the Briefing Order, as discussed
26 below. In particular, we will adopt a revised low-end outlier test that
27 eliminates proxy group ROE results that are less than the yields of generic
28 corporate Baa bonds plus 20 percent of the CAPM risk premium.
29

¹ *Pioneer Transmission, LLC*, 126 FERC ¶ 61,281 at P 94 (March 27, 2009).

² *Southern California Edison Co.*, 92 FERC ¶ 61,266 (2000) (Opinion No. 445).

³ *Southern California Edison Co.*, 131 FERC ¶ 61020 at P 55 (April 15, 2010).

1 We find that 20 percent of the risk premium from the CAPM analysis
2 described above is a reasonable risk premium to apply to the low-end
3 outlier test. Because the risk premium that investors demand changes over
4 time, it is imprecise to simply add 100 basis points to the bond yield. The
5 methodology that we adopting in this order captures such changes because
6 the risk premium from the CAPM analysis reflects investors' required risk
7 premium under the prevailing market conditions⁴.
8

9 In a subsequent Order⁵, the FERC reaffirmed its approach of referencing 20 percent of the
10 CAPM risk premium when conducting its low-end outlier evaluations.

11 In my judgment, the FERC's revised low-end outlier methodology for DCF estimates is an
12 improvement over its previous approach, as it now better captures the dynamic nature of
13 the market risk premium, thus enabling the cost of capital analyst to appropriately apply
14 fundamental tests of economic logic to his/her preliminary DCF results.
15

16
17 3. Applying the FERC's Revised Approach in
18 Determining the "Low-End" Outlier Threshold
19
20

21 As further described within page 6 of Exhibit VVR-7, after applying the FERC's revised
22 low-end outlier methodology as outlined above, I have determined that a reasonable low-
23 end outlier threshold to apply to my preliminary DCF results is 7.00 percent.⁶ I have
24 therefore eliminated outlier estimates falling below this minimum threshold level.
25 Consistent with the risk-and-return investment principle, investors cannot reasonably be
26 expected to accept equity returns below this threshold, since on a risk-adjusted basis,
27 fixed-income securities would likely offer investors a superior investment alternative.

28 4. Regulatory Precedents for Determining the "High-End"
29 Threshold for Outlier Results

⁴ *Association of Businesses Advocating Tariff Equity, et al., v. Midcontinent Independent System Operator, Inc., et al.*, 169 FERC ¶ 61,129, Opinion No. 569, at P 387 and P 388 (November 21, 2019).

⁵ *Association of Businesses Advocating Tariff Equity, et al., v. Midcontinent Independent System Operator, Inc., et al.*, 171 FERC ¶ 61,154, Opinion No. 569-A, at P 161-162 (May 21, 2020).

⁶ Rounded down from 7.01 percent to 7.00 percent.

1
2
3 In *Opinion No. 569*, the FERC also adopted a revised high-end outlier test, whereby
4 companies having DCF estimates in excess of 150 percent of the median value of the initial
5 proxy group results would be excluded from the final group. In a subsequent Order⁷, the
6 FERC elected to modify this approach by instead referencing 200 percent of the median
7 value of the initial proxy group results, and the FERC subsequently reaffirmed this
8 decision in yet another Order⁸. I have taken a similar approach in identifying high-end
9 outlier results in my DCF analyses, but have eliminated *individual* high-end estimates,
10 rather than fully eliminating the company from the proxy group. In my judgement, this
11 approach is appropriate in view of the relatively small number of regulated utility holding
12 companies to choose from in forming a utility proxy group, which is largely attributable to
13 recent merger and acquisition activity in the utility industry.

14 To further screen my DCF results for high-end outlier estimates, I have also
15 considered the FERC's previous high-end outlier methodology in my DCF analyses.
16 Specifically, in *ISO New England*,⁹ the FERC determined that proxy group companies with
17 DCF estimates in excess of 17.7 percent should be excluded from DCF analyses.
18 Accordingly, as a further check on the high-end outlier threshold applied within my DCF
19 analyses, I have also given some consideration to the 17.7 percent high-end threshold
20 established in the *ISO New England* case. The results of the high-end outlier screens for
21 my DCF analyses can be found on pages 1 and 2 of Exhibit VVR-7, Exhibit VVR-8 and
22 Exhibit VVR-9, respectively.

⁷ *Association of Businesses Advocating Tariff Equity, et al., v. Midcontinent Independent System Operator, Inc., et al.*, 171 FERC ¶ 61,154, Opinion No. 569-A, at P 154 (May 21, 2020).

⁸ *Association of Businesses Advocating Tariff Equity, et al., v. Midcontinent Independent System Operator, Inc., et al.*, 173 FERC ¶ 61,159, Opinion No. 569-B, at P 140 (November 19, 2020).

⁹ *ISO New England, Inc. et al.*, 109 FERC ¶ 61,147 at P 205 (November 3, 2004).

Appendix C

Financial Risk Adjustments to DCF Results
Recognizing Differences in Market Value vs. Book Value Capitalization Levels

1. Circumstances Under Which a Financial Risk Adjustment is Required for DCF Results

A financial risk or “leverage” adjustment to DCF results is required whenever the average market value equity capitalization of the proxy companies being analyzed is materially higher than the corresponding book value equity capitalization. Stated alternatively, a leverage adjustment is required whenever the average per-share market-to-book ratio of the group materially exceeds 1.0. Whenever a significant market-to-book value disparity exists for a utility, the level of financial risk implicit in the respective market value and book value capital structures can differ substantially. In particular, the market value based capital structure will reflect a higher relative equity capitalization, a lower relative debt capitalization, and therefore less financial risk as compared to the book value capital structure. In contrast, the book value capital structure will reflect a lower relative equity capitalization and a higher relative debt capitalization, thereby indicating a higher degree of financial risk.

To understand the need for a leverage adjustment, it must first be emphasized that DCF cost of equity estimates are market-based estimates which are derived by referencing the stock prices of comparable risk companies as direct inputs into the DCF model. DCF estimates therefore reflect the return expectations of investors based upon the level of financial risk embedded within the corresponding market value capital structure, as indicated by the current stock price. Equity investors are predominately concerned with a firm’s market value capital structure, since it reflects the current value of their investment and therefore provides the basis for assessing a company’s financial risk profile. To the extent that a book value based capital structure will be utilized in the rate-

1 setting process, equity investors will expect an additional return premium to be
2 compensated for the additional financial risk inherent within a book value capital
3 structure. Multiple academic studies have demonstrated that a strong positive correlation
4 exists between the amount of leverage in a firm's capital structure and its cost of equity
5 capital, which Morin discusses in *Modern Regulatory Finance*, a widely-recognized
6 authoritative guide on utility cost of capital matters, as follows:

7 the one inescapable conclusion from the research is that debt affects
8 the cost of equity and that a company has a different cost of equity at a
9 different capital structure, with the cost of equity rising as leverage
10 increases. Therefore, the capital structure used to estimate the cost of
11 equity is an integral inseparable part of that estimate.¹

12
13 Therefore, if market-based DCF estimates of the cost of equity are applied to a utility's
14 book value capital structure in determining the utility's weighted average cost of capital, a
15 leverage adjustment is required to recognize the increase in financial risk resulting from
16 the use of the book value capital structure, rather than the market-value capital structure.
17 It is clear that this adjustment is necessary, since as Morin explains above, "*a company*
18 *has a different cost of equity at a different capital structure.*" Absent this leverage
19 adjustment, the DCF results will be incorrectly specified, since they will reflect the lower
20 level of financial risk associated with a market value based capital structure, rather than
21 the higher risk associated with the book value capital structure, to which the DCF results
22 will be applied.

23 2. Regulatory Precedents Supporting the Use of Financial Risk Adjustments Based on
24 Differences in Market-Value and Book-Value Capitalization Levels

25
26 On numerous occasions, the Pennsylvania Public Utility Commission has allowed upward
27 adjustments to the cost of equity to recognize the difference in financial risk between

¹ Roger A. Morin, *Modern Regulatory Finance* (PUR Books LLC, 2021), at 521.

market value based capital structures, which are the basis of DCF estimates, and the book value capital structures used for rate-setting purposes.

3. Determining the Appropriate Financial Risk or “Leverage” Adjustment Utilizing Modigliani and Miller’s Classic Financial Theorems

In formulating my proposed leverage adjustments, I have referenced the classic financial theorems of Nobel laureates Modigliani and Miller (M&M), which demonstrated the relationship between a firm’s capital structure, its valuation, and its cost of capital.² Based on the M&M equation for the cost of equity, and the respective market value and book value capital structure ratios for the Gas LDC Group, the required financial risk or “leverage” adjustments was determined to be as reflected in Table C-1 below:

Table C-1	
Required Financial Leverage Adjustments	
Gas LDC Group	0.64%
Combination Utility Group	0.64% ³
Non-Regulated Group	0.64% ⁴

Supporting calculations for the recommended leverage adjustment is as follows:

$$K_e = p + (p-i) (1-T) (B/S) + (p-d) P/S \quad (\text{Equation C.1})$$

² Franco Modigliani and Merton H. Miller, “Taxes and the Cost of Capital: A Correction,” *American Economic Review*, 53 (June 1963), 433-443; Franco Modigliani and Merton H. Miller, *The Cost of Capital, Corporation Finance and the Theory of Investments*, *American Economic Review* 48 (June 1958) at 261-297.

³ For both the Combination Utility Group and the Non-Regulated Group, the magnitude of the difference between the average market value capital structures of these two proxy groups and their respective book value based capital structures are significantly greater than the difference between the average market value capital structure of the Gas LDC Group and its book value capital structure. As such, under the M&M equation, the required financial leverage adjustment for the Combination Utility Group and the Non-Regulated Group would be significantly greater than that of the Gas LDC Group. To recognize this disparity and make the leverage adjustment relevant to a typical gas utility capital structure, I have applied the same adjustment that I applied to the Gas LDC Group (0.64%) to both the Combination Utility Group and the Non-Regulated Group. Utilizing this approach ensures a more conservative analysis.

⁴ Id.

Where:

K_e = Estimated cost of equity

p = Cost of equity for a firm financed with 100% equity capital

i = Long-term debt borrowing cost

T = Marginal corporate income tax rate

B = Debt to total capitalization ratio

S = Common stock to total capitalization ratio

d = Preferred stock dividend yield

P = Preferred stock to total capitalization ratio

Gas LDC Group

$$K_e = p + (p-i) (1-T) (B/S) + (p-d) P/S \quad (\text{Equation C.1})$$

$$10.40\% = 8.73\% + (8.73\% - 5.69\%) (1-0.27)(42.0/57.0) + (8.73\% - 6.74\%) (1.0/57.0)$$

$$11.04\% = 8.73\% + (8.73\% - 5.69\%) (1-0.27)(50.1/48.9) + (8.73\% - 6.74\%) (1.0/48.9)$$

$$\text{Leverage adjustment} = 11.04\% - 10.40\% = 0.64\%$$

Appendix D
Flotation Costs

1. Adjusting the “Bare Bones” Cost of Equity for Flotation Costs

When common equity is employed to finance a utility’s rate base, it is either derived from new stock sales or from the retention of undistributed earnings. In cases where a utility or its parent company “floats” a new equity issuance, significant issuance or flotation costs are involved, including underwriting discounts, legal fees, accounting fees and printing costs. After subtracting these out-of-pocket costs from the transaction’s gross proceeds, the company is left with net proceeds which are materially lower than the amount invested by the company’s equity investors. Considering that only net proceeds can be invested into a company’s rate base, the amount invested by equity investors which funds flotation-related costs will never earn a fair return for those investors. As such, if a flotation cost adjustment is not made to the “bare-bones” cost of equity determined by the various market-based models, the company’s equity investors will not earn a fair return on their entire investment, thereby understating the company’s legitimate revenue requirement. This is contrary to established regulatory practices for debt issuance costs, which are typically capitalized at the time of issuance and amortized over the life of the outstanding debt, therefore being fully recoverable through the cost of service ratemaking process.

2. Flotation Costs – Multiple of Cost of Equity Approach

Numerous adjustment methods have been proposed to incorporate equity issuance costs into rate proceedings, several of which have been accepted by state regulatory commissions, including the DCF formula approach, multiple of cost of equity approach, basis point approach, and the actual costs approach. For purposes of this proceeding, I

1 have relied upon the “multiple of cost of equity” approach in determining the appropriate
2 flotation cost adjustment for each of the three proxy groups.

3 In contrast to debt capital, equity capital is considered to have an infinite life, and it would
4 therefore be inappropriate to amortize a company’s flotation costs over a finite number of
5 years. As such, rather than seeking a “return of” its flotation costs over some arbitrarily
6 selected amortization period, it is more appropriate for a utility to seek a “return on” its
7 flotation costs, as these costs constitute a permanent equity contribution by investors.
8 CPA’s ultimate parent company, NiSource Inc., has completed a number of equity
9 offerings over the past twenty-plus years which have benefitted NiSource’s utility
10 subsidiaries. Specifically, NiSource completed a \$734.9 million equity offering during
11 November, 2002 with an underwriting discount of 3.00 percent; a \$348.0 million equity
12 offering during September, 2010 with an underwriting discount of 3.25 percent; and a
13 \$606.0 million private placement of common equity during May 2018, with associated
14 placement fees of approximately 1.00 percent.

15 In addition, on April 19, 2021, NiSource completed the sale of 8.625 million Series A
16 Equity Units, initially consisting of Series A Corporate Units, each with a stated amount of
17 \$100. The equity offering generated net proceeds of \$835.5 million, after underwriting
18 and issuance expenses. The underwriting and issuance expenses associated with the
19 transaction were approximately \$27.0 million, which constitutes approximately 3.00
20 percent of the gross proceeds from the transaction.

21 Furthermore, during the years 2017-2024, NiSource issued additional shares of common
22 stock under the company’s “at-the market” (or “ATM”) equity issuance program, which

1 resulted in \$1.9 billion of cumulative net proceeds during the 2017-2024 period.¹ To date,
2 the distribution fees payable to the equity distribution agents facilitating these “at-the-
3 market” transactions have approximated 0.80 percent - 1.00 percent of the notional value
4 of these transactions. Additional supporting details on NiSource’s ATM and block equity
5 transactions can be found within NiSource’s SEC filings, including its 10-K, 10-Q and
6 Prospectus Supplement filings.

7
8 After considering both NiSource’s past and future anticipated equity issuances as
9 discussed above, I have concluded that a reasonable overall flotation cost value to
10 reference for purposes of the instant proceeding should reflect a composite of the equity
11 underwriting and placement fees paid by NiSource over the past twenty-plus years, and
12 have therefore referenced a composite value of 1.75 percent.

13 Considering that the contributed capital component of CPA’s common equity account has
14 recently been in the range of 15 percent of the Company’s total common equity balance, it
15 is reasonable to apply a flotation cost adjustment to CPA’s cost of equity that is based on
16 this 15 percent weighting, since the remaining 85 percent weighting allocated to
17 undistributed retained earnings would not be subject to underwriting costs. Accordingly,
18 in deriving my recommended flotation cost adjustment, I have applied a 15 percent
19 weighting to the 1.75 percent composite flotation cost value previously discussed, which
20 yields a flotation cost factor of 0.2625 percent ($1.75\% \times 15\% = 0.2625\%$). To properly apply
21 this level of flotation costs to CPA’s cost of equity under the “multiple of cost of equity”
22 approach, the 0.2625 percent flotation cost factor must be added to 100 percent of CPA’s
23 pre-adjusted cost of equity, which is derived in mathematical terms as follows:

¹ Notably, NiSource did not issue any additional common equity shares under its ATM program during calendar-year 2023.

1 (1+.002625=1.002625%). Therefore, based upon the above approach, I have applied a
2 1.002625 percent multiple to the *pre-adjusted* indicated cost of equity for each of the
3 respective proxy groups.

Vincent V. Rea, CRRA
Professional Qualifications and Expert Testimony Listing

Testimony and Regulatory Litigation Support

Mr. Rea has provided expert testimony in utility regulatory proceedings before state commissions and the Federal Energy Regulatory Commission in connection with rate cases, financing applications, and various other financing-related matters. His testimony has focused on a number of topics, including the cost of equity (ROE), overall cost of capital and fair rate of return, appropriate ratemaking capital structure, embedded cost of debt, rating agency matters, utility recapitalizations, and various other financial-related matters. Mr. Rea has collaborated with utility company regulatory staff and outside counsel in the development of litigation strategies supporting rate proceedings, including testimony development, responding to discovery requests from intervenors and commission staff, appearing at evidentiary hearings, and in the preparation of legal briefs. Mr. Rea currently serves as Managing Director, Regulatory Finance Associates, LLC, and independent financial and regulatory consulting firm serving the utility industry. He previously held the positions of Director, Regulatory Finance and Economics for NiSource Inc., and Assistant Treasurer and Director of Corporate Finance for NiSource Inc. A detailed listing of the docketed proceedings where testimony and/or subject matter support has been provided by Mr. Rea can be found in Attachment A.

Capital Markets Expertise

Mr. Rea acquired broad-based capital markets experience supporting the utility industry over a period of 15 years while serving in the capacity as Financial Officer for NiSource Inc., NiSource Finance Corp., and each of NiSource's six utility subsidiaries. Mr. Rea's extensive capital markets experience in the utility industry is a distinguishing factor that uniquely qualifies him to opine on the cost of capital for regulated utilities. In the capacity as Assistant Treasurer, Mr. Rea led or co-led over twenty debt and equity financing transactions completed in both the public and private capital markets, with an aggregate principal value in excess of \$10.0 billion. Mr. Rea also led or co-led numerous bank loan syndication, commercial paper and structured finance transactions having an aggregate value in excess of \$11.0 billion. He was responsible for NiSource's enterprise-wide activities in the areas of debt liability management, including multiple tender offer transactions; interest rate risk management; derivative transactions; banking and capital market relationships; rating agency relationships; pension fund management; and oversight of the Company's treasury operations. A detailed listing of Mr. Rea's transactional experience in the capital markets supporting the utility industry is provided in Attachment B.

Professional Background

Managing Director, Regulatory Finance Associates, LLC (2020-present)

Director, Regulatory Finance and Economics, NiSource Inc. (2015-2020)

Assistant Treasurer and Corporate Officer, NiSource Inc. (2009-2015)

Assistant Treasurer, NiSource Finance Corp. and NiSource utility subsidiaries (2001-2015)

Director, Corporate Finance, NiSource Inc. (2001-2009)

Vincent V. Rea, CRRA
Professional Qualifications and Testimony Listing

Educational Background

M.B.A. in Finance, Indiana University, Bloomington, Indiana

B.A. with Honors in Business and Accounting, Lake Forest College, Lake Forest, Illinois

Certifications

Certified Rate of Return Analyst (CRRA), Society of Utility and Regulatory Financial Analysts

Certified Public Accountant (CPA), State of Illinois

Series 65 Uniform Investment Adviser Law Examination

Seminars/Conferences

- Society of Utility and Regulatory Financial Analysts Financial Forum (52nd Annual, 2021)
- Society of Utility and Regulatory Financial Analysts Financial Forum (51st Annual, 2019)
- Society of Utility and Regulatory Financial Analysts Financial Forum (50th Annual, 2018)
- Society of Utility and Regulatory Financial Analysts Financial Forum (49th Annual, 2017)
- Society of Utility and Regulatory Financial Analysts Financial Forum (48th Annual, 2016)
- Advanced Regulatory Studies Program, Institute of Public Utilities, Michigan State University (2015)
- Society of Utility and Regulatory Financial Analysts Financial Forum (47th Annual, 2015)
- American Gas Association (AGA) Financial Forum (2014)
- Society of Utility and Regulatory Financial Analysts Financial Forum (46th Annual, 2014)
- Essentials of Regulatory Finance, SNL Financial, Primary Instructor: Roger A. Morin, Ph.D. (2013)
- Society of Utility and Regulatory Financial Analysts Financial Forum (45th Annual, 2013)
- Society of Utility and Regulatory Financial Analysts Financial Forum (44th Annual, 2012)
- NARUC Utility Rate School (39th Annual Eastern), Committee on Water of NARUC (2011)
- Society of Utility and Regulatory Financial Analysts Financial Forum (43th Annual, 2011)
- Southern Gas Association (SGA) Ratemaking School (2011)
- Edison Electric Institute (EEI) Financial Conference (46th Annual, 2011)
- Edison Electric Institute (EEI) Financial Conference (45th Annual, 2010)

Vincent V. Rea, CRRA
Professional Qualifications and Testimony Listing

Memberships/Associations

Society of Utility and Regulatory Financial Analysts (SURFA).

Presentations

“Do Cost of Equity Models (e.g. DCF Model) Understate the Cost of Equity?”, Society of Utility and Regulatory Financial Analysts Financial Forum (52nd Annual, 2021), Panel Presentation.

“Financial Engineering in the Utility Sector and its Impact on the Cost of Capital”, Society of Utility and Regulatory Financial Analysts Financial Forum (47th Annual, 2015), Presentation and Panel Moderator.

“Ratemaking Capital Structure: Holding Company vs. Operating Company”, Society of Utility and Regulatory Financial Analysts Financial Forum (45th Annual, 2013), Presentation and Panel Moderator.

Vincent V. Rea
Testimony in Utility Regulatory Proceedings

Applicant	Date	Docket/Type of Case	Subject
Testimony before the Massachusetts Department of Public Utilities (D.P.U.)			
NSTAR Electric Company d/b/a Eversource Energy	01/2022	D.P.U. 22-22 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	04/2018	D.P.U. 18-45 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	09/2015	D.P.U. 15-139 Financing Petition	Financing Authority (\$95.0 million)
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	04/2015	D.P.U. 15-50 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	08/2013	D.P.U. 13-129 Financing Petition	Financing Authority (\$50.0 million)
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	04/2013	D.P.U. 13-75 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	04/2012	D.P.U. 12-25 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Bay State Gas Company, d/b/a Columbia Gas of Massachusetts	05/2011	D.P.U. 11-41 Financing Petition	Financing Authority (\$100.0 million)
Bay State Gas Company	08/2004	D.T.E. 04-80 Financing Petition	Financing Authority (\$120.0 million)
Bay State Gas Company	11/2002	D.T.E. 02-73 Financing Petition	Financing Authority (\$50.0 million)
Bay State Gas Company	09/2001	D.T.E. 01-75 Participation in Intra-System Financing Vehicle	Participation in NiSource Money Pool System

Vincent V. Rea
Testimony in Utility Regulatory Proceedings

Applicant	Date	Docket/Type of Case	Subject
Testimony before the Connecticut Public Utilities Regulatory Authority (PURA)			
Connecticut Light and Power Co. d/b/a Eversource Energy	05/2021	Docket No. 17-12-03RE11 PURA Investigation into Dist. System Planning - New Rate Designs and Rates Review	Cost of Capital (ROE) Capital Structure
Testimony before the Indiana Utility Regulatory Commission (IURC)			
Northern Indiana Public Service Company	10/2023	Cause No. 45967 Base Rate Proceeding (Gas)	Cost of Capital (ROE)
Northern Indiana Public Service Company	09/2022	Cause No. 45772 Base Rate Proceeding (Electric)	Cost of Capital (ROE)
Northern Indiana Public Service Company	09/2021	Cause No. 45621 Base Rate Proceeding (Gas)	Cost of Capital (ROE)
Northern Indiana Public Service Company	09/2021	Cause No. 45330-TDSIC-1 TDSIC Proceeding (Gas)	Cost of Capital (ROE) Capital Structure
Northern Indiana Public Service Company	10/2018	Cause No. 45159 Base Rate Proceeding (Electric)	Cost of Capital (ROE) Capital Structure
Northern Indiana Public Service Company	06/2018	Cause No. 45113 Financing Petition	Financing Authority (\$470.0 million)
Northern Indiana Public Service Company	09/2017	Cause No. 44988 Base Rate Proceeding (Gas)	Cost of Capital (ROE) Capital Structure
Northern Indiana Public Service Company	12/2017	Cause No. 45020 Amendment to Financing Petition	Financing Authority (\$700.0 million)
Northern Indiana Public Service Company	06/2016	Cause No. 44796 Financing Petition	Financing Authority (\$500.0 million)
Northern Indiana Public Service Company	10/2015	Cause No. 44688 Base Rate Proceeding (Electric)	Overall Cost of Capital Capital Structure Credit Ratings

Vincent V. Rea
Testimony in Utility Regulatory Proceedings

Applicant	Date	Docket/Type of Case	Subject
Testimony before the Indiana Utility Regulatory Commission (IURC) (continued)			
Northern Indiana Public Service Company	11/2010	Cause No. 43969 Base Rate Proceeding (Electric)	Financing Activities Credit Ratings Cost of Debt
Northern Indiana Public Service Co., Kokomo Gas & Fuel Co., Northern Indiana Fuel & Light Co.	09/2010	Cause No. 43941 Merger Petition and Transfer of Franchise	Benefits of Proposed Merger
Northern Indiana Public Service Company	05/2010	Cause No. 43894 Base Rate Proceeding (Gas)	Financing Activities Credit Ratings Cost of Debt
Northern Indiana Public Service Company	08/2008	Cause No. 43563 Financing Petition	Financing Authority for CCGT Generation (\$120.0 million)
Northern Indiana Public Service Company	06/2008	Cause No. 43526 Base Rate Proceeding (Electric)	Financing Activities Credit Ratings Cost of Debt
Testimony before the Kentucky Public Service Commission (PSC)			
Columbia Gas of Kentucky	05/2021	Case No. 2021-00183 Base Rate Proceeding (Gas)	Cost of Capital (ROE) Capital Structure
Testimony before the Maryland Public Service Commission (PSC)			
Columbia Gas of Maryland	05/2023	Case No. 9701 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	05/2022	Case No. 9680 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	05/2021	Case No. 9664 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	05/2020	Case No. 9644 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	05/2019	Case No. 9609 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	04/2018	Case No. 9480 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	04/2017	Case No. 9447 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure

Vincent V. Rea
Testimony in Utility Regulatory Proceedings

Applicant	Date	Docket/Type of Case	Subject
Testimony before the Maryland Public Service Commission (PSC) (continued)			
Columbia Gas of Maryland	04/2016	Case No. 9417 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Maryland	02/2013	Case No. 9316 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Testimony before the New Hampshire and Maine Public Utility Commissions			
Northern Utilities, Inc.	03/2003	Docket No. 03-080 (NH) Case No. 2003-00222 (ME) Financing Petition	Financing Authority (\$60.0 million)
Northern Utilities, Inc.	11/2002	Case No. 2002-00680 (ME) Financing Vehicle	Alternative Fuel Financing Arrangement
Northern Utilities, Inc.	09/2001	Case No. 2001-00646 (ME) Participation in Intra- System Financing Vehicle	Participation in a Funds Pooling Agreement
Testimony before the Virginia State Corporation Commission (SCC)			
Columbia Gas of Virginia	04/2022	PUR-2022-00036 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Virginia	08/2018	PUR-2018-00131 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Virginia	04/2016	PUE-2016-00033 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Columbia Gas of Virginia	04/2014	PUE-2014-00020 Base Rate Proceeding	Cost of Capital (ROE) Capital Structure
Testimony before the Federal Energy Regulatory Commission (FERC)			
Northern Indiana Public Service Company	03/2012	Docket No. EL12-49-000 Transmission Rate Incentives for MVP Projects	Incentive Rate Treatment - CWIP and Abandoned Plant

Vincent V. Rea
Subject Matter Support in Regulatory Proceedings
(Representative Cases)

Applicant	Date	Docket/Type of Case	Subject
Virginia State Corporation Commission			
Columbia Gas of Virginia	10/2016	PUE-2016-00129 Financing Petition	Financing Authority (\$60.0 million)
Columbia Gas of Virginia	10/2014	PUE-2014-00109 Financing Petition	Financing Authority (\$240.0 million)
Columbia Gas of Virginia	10/2012	PUE-2012-00126 Financing Petition	Financing Authority (\$175.0 million)
Maryland Public Service Commission			
Columbia Gas of Maryland	12/2018	Case No. 9601 Financing Petition	Financing Authority (\$21.0 million)
Columbia Gas of Maryland	09/2016	Case No. 9427 Financing Petition	Financing Authority (\$20.0 million)
Columbia Gas of Maryland	07/2014	Case No. 9359 Financing Petition	Financing Authority (\$10.0 million)
Public Utilities Commission of Ohio			
Columbia Gas of Ohio	09/2015	Case No. 15-1548-GA-AIS Financing Petition	Financing Authority (\$300.0 million)
Columbia Gas of Ohio	08/2014	Case No. 14-1523-GA-AIS Financing Petition	Financing Authority (\$300.0 million)
Columbia Gas of Ohio	07/2012	Case No. 12-2056-GA-AIS Financing Petition	Financing Authority (\$300.0 million)
Pennsylvania Public Utility Commission			
Columbia Gas of Pennsylvania	11/2017	Docket No. S-2017- 2632449	Financing Authority (\$160.0 million)
Columbia Gas of Pennsylvania	11/2015	Docket No. S-2015- 2515414	Financing Authority (\$130.0 million)

Vincent V. Rea
Subject Matter Support in Regulatory Proceedings
(Representative Cases)

Applicant	Date	Docket/Type of Case	Subject
Columbia Gas of Pennsylvania	11/2013	Docket No. S-2013-2395719 Financing Petition	Financing Authority (\$150.0 million)
Columbia Gas of Pennsylvania	12/2011	Docket No. S-2012-2282635 Financing Petition	Financing Authority (\$185.0 million)
Kentucky Public Service Commission			
Columbia Gas of Kentucky	10/2018	Case No. 2018-00356 Financing Petition	Financing Authority (\$40.0 million)
Columbia Gas of Kentucky	10/2015	Case No. 2015-00354 Financing Petition	Financing Authority (\$58.0 million)
Columbia Gas of Kentucky	09/2012	Case No. 2012-00418 Financing Petition	Financing Authority (\$45.0 million)
Federal Energy Regulatory Commission			
Northern Indiana Public Service Company	06/2015	Docket No. ES15-33-000 Short-Term Debt Authority Under Federal Power Act	Short-Term Debt Authority (\$1.0 billion)
Northern Indiana Public Service Company	05/2013	Docket No. ES13-25-000 Short-Term Debt Authority Under Federal Power Act	Short-Term Debt Authority (\$1.0 billion)
Securities and Exchange Commission - PUHCA Authority			
Columbia Energy Group and Columbia Gas of Ohio, Inc.	07/2004	HCAR No. 27899 Factoring Arrangement	Capital Contribution to Factoring Subsidiary
NiSource Inc. and Subsidiaries	11/2003	HCAR No. 27789 U-1 Financing Application	U-1 Financing PUHCA of 1935
NiSource Inc. and Subsidiaries	09/2002	HCAR No. 27567 Tax Allocation Agreement	U-1 Tax Allocation Agreement
Bay State Gas Company, Northern Utilities, Inc., and Granite State Gas Transmission, Inc.	08/2002 & 06/2002	HCAR Nos. 27559/27535 Intra-System Financing Vehicle	Release of Jurisdiction to Participate in NiSource Money Pool System
NiSource Inc. and Subsidiaries	12/2001	HCAR No. 27479 Intra-System Financing	Establish Money Pool System

Vincent V. Rea
Professional Experience in the Capital Markets

Transaction Type	Date	Company/Issuer	Transaction Size
Initial Public Offering (Equity)	02/2015	Columbia Pipeline Partners, L.P.	\$1.2 billion
Public Debt Offering (30-year/10-year)	06/2012	NiSource Finance Corp.	\$750.0 million
Revolving Credit Facility Amendment	05/2012	NiSource Finance Corp.	\$1.5 billion
Tender Offer for Senior Unsecured Notes	12/2011	NiSource Finance Corp.	\$250.0 million
Public Debt Offering (30-year/10-year)	11/2011	NiSource Finance Corp.	\$500.0 million
Public Debt Offering (30-year)	06/2011	NiSource Finance Corp.	\$400.0 million
Commercial Paper Program Implementation	06/2011	NiSource Finance Corp.	\$500.0 million
Revolving Credit Facility	03/2011	NiSource Finance Corp.	\$1.5 billion
Tender Offer for Senior Unsecured Notes	12/2010	NiSource Finance Corp.	\$273.0 million
Public Debt Offering (30-year)	12/2010	NiSource Finance Corp.	\$250.0 million
Equity Offering (Forward Equity Offering)	09/2010	NiSource Inc.	\$400.0 million
Project Financing (Private Placement)	08/2010	Millennium Pipeline Company	\$725.0 million
Accounts Receivable Securitization Program	03/2010	Columbia Gas of Pennsylvania	\$75.0 million
Public Debt Offering (12-year)	12/2009	NiSource Finance Corp.	\$500.0 million
Accounts Receivable Securitization Program	10/2009	Columbia Gas of Ohio	\$275.0 million

Vincent V. Rea
Professional Experience in the Capital Markets

Transaction Type	Date	Company/Issuer	Transaction Size
Accounts Receivable Securitization Program	10/2009	Northern Indiana Public Service Company	\$200.0 million
Term Loan Facility	04/2009	NiSource Finance Corp.	\$385.0 million
Tender Offer for Senior Unsecured Notes	04/2009	NiSource Finance Corp.	\$251.0 million
Public Debt Offering (7-year)	03/2009	NiSource Finance Corp.	\$600.0 million
Open Market Repurchases of Senior Unsecured Notes	01/2009	NiSource Finance Corp.	\$100.0 million
Revolving Credit Facility	09/2008	NiSource Finance Corp.	\$500.0 million
Reoffering of Tax-Exempt Pollution Control Bonds	08/2008	Jasper County, Indiana (on behalf of Northern Indiana Public Service Company)	\$254.0 million
Public Debt Offering (5-year/10-year)	05/2008	NiSource Finance Corp.	\$700.0 million
Construction Financing Credit Facility	08/2007	Millennium Pipeline Company	\$800.0 million
Public Debt Offering (10-year)	08/2007	NiSource Finance Corp.	\$800.0 million
Project Financing (Private Placement)	06/2006	Hardy Storage Project (Hardy Storage Company)	\$124.0 million
Private Placement Debt Offering (multiple tranches)	11/2005	NiSource Finance Corp.	\$900.0 million
Bilateral Revolving Credit Facility	11/2005	NiSource Finance Corp.	\$300.0 million
Public Debt Offering (12-year/15-year)	09/2005	NiSource Finance Corp.	\$1.0 billion
Revolving Credit Facility	03/2005	NiSource Finance Corp.	\$1.25 billion

Vincent V. Rea
Professional Experience in the Capital Markets

Transaction Type	Date	Company/Issuer	Transaction Size
Public Debt Offering (5-year floating rate notes)	11/2004	NiSource Finance Corp.	\$450.0 million
Settlement of Forward Stock Purchase Agreements and Remarketing of Debentures	11/2004	NiSource Inc. (Mandatorily-Convertible Hybrid Securities)	\$144.0 million
Accounts Receivable Securitization Program	05/2004	Columbia Gas of Ohio	\$300.0 million
Revolving Credit Facilities (364-day/3-year)	03/2004	NiSource Finance Corp.	\$1.25 billion
Refunding of Tax-Exempt Pollution Control Bonds	12/2003	Jasper County, Indiana (on behalf of Northern Indiana Public Service Company)	\$55.0 million
Accounts Receivable Securitization Program	12/2003	Northern Indiana Public Service Company	\$200.0 million
Public Debt Offering (1.5-year floating/3-year)	11/2003	NiSource Finance Corp.	\$500.0 million
Public Debt Offering (11-year)	07/2003	NiSource Finance Corp.	\$500.0 million
Settlement of Forward Stock Purchase Agreements and Remarketing of Debentures	02/2003	NiSource Inc. (Mandatorily-Convertible Hybrid Securities)	\$345.0 million
Equity Offering	11/2002	NiSource Inc.	\$735.0 million
Revolving Credit Facility (364-day)	03/2002	NiSource Finance Corp.	\$500.0 million
Public Debt Offering (2-year)	04/2001	NiSource Finance Corp.	\$300.0 million
Post-Merger Consolidation of Bank Credit Facilities and Commercial Paper Facilities	03/2001	NiSource Inc. Columbia Energy Group NiSource Finance Corp.	\$2.5 billion

Columbia Gas of Pennsylvania, Inc.
Comparative Risk Assessment - 2019-2023 and 5-Year Averages

Exhibit VVR-2

Page 1 of 4

Business & Other Hybrid Metrics (1)	2023	2022	2021	2020	2019	5-Year Average
Relative Size Comparison - Total Capital						
Permanent Capitalization (excl. OCI)	\$ 2,913,652	\$ 2,618,730	\$ 2,355,995	\$ 2,020,520	\$ 1,768,935	\$ 2,335,566
Current Maturities and Short-Term Debt	78,538	144,432	165,691	188,183	142,398	143,848
Total Capitalization (excl. OCI)	\$ 2,992,190	\$ 2,763,162	\$ 2,521,686	\$ 2,208,703	\$ 1,911,333	\$ 2,479,415

Standard Deviation and Coefficient of Variation of Return on Book Equity

Return on Avg. Book Equity, incl. AFUDC (2)	9.3%	11.6%	9.0%	8.2%	10.4%	9.7%
	Average	Std. Dev.	Coff. Var.			
Return on Avg. Book Equity, incl. AFUDC (2)	9.70%	1.18%	0.122			

Financial Risk/Credit Quality Metrics	2023	2022	2021	2020	2019	5-Year Average
Permanent Capitalization Ratios						
Long-Term Debt	44.1%	43.4%	44.0%	44.3%	44.4%	44.0%
Preferred Stock	-	-	-	-	-	-
Common Equity (2)	55.9%	56.6%	56.0%	55.7%	55.6%	56.0%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Total Capitalization Ratios

Total Debt (incl. CMD and STD)	45.6%	46.3%	47.6%	49.1%	48.5%	47.4%
Preferred Stock	-	-	-	-	-	-
Common Equity (2)	54.4%	53.7%	52.4%	50.9%	51.5%	52.6%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

EBITDA Interest Coverage (3)

EBITDA Interest Cov. (incl. AFUDC ded.)	6.17	7.09	6.19	5.55	6.17	6.23

FFO to Adjusted Total Debt (4)

FFO to Adj. Debt (incl. AFUDC ded.)	20.1%	21.6%	17.5%	16.1%	19.3%	18.9%

(1) Columbia Gas of Pennsylvania, Inc. standalone risk metrics.

(2) Excludes Other Comprehensive Income (Loss) component of Stockholders' Equity.

(3) Earnings before interest, taxes, depreciation and amortization, divided by interest expense (including capitalized AFUDC interest).

(4) Funds from Operations (net income, including AFUDC, plus depreciation, amortization and deferred income taxes) divided by Adjusted Total Debt (total debt, incl. current maturities and short-term debt, plus post-retirement obligations recognized within the balance sheet).

Gas LDC Group
Comparative Risk Assessment - 2019-2023 and 5-Year Averages

Exhibit VVR-2

Page 2 of 4

Business & Hybrid Risk Metrics (1)	2023	2022	2021	2020	2019	5-Year Average
Relative Size Comparison - Total Capital						
Permanent Capitalization (excl. OCI)	10,041,215	8,863,999	8,348,488	7,105,910	6,326,344	\$ 8,137,191
Current Maturities and Short-Term Debt	1,038,102	1,334,335	1,139,420	366,732	691,656	\$ 914,049
Total Capitalization (excl. OCI)	11,079,317	10,198,334	9,487,909	7,472,642	7,018,000	\$ 9,051,240

Standard Deviation and Coefficient of Variation of Return on Book Equity

Return on Avg. Book Equity (2)(incl. AFUDC)	7.90%	8.38%	9.23%	9.43%	9.45%	8.88%
	Average	Std. Dev.	Coeff. Var.			
Return on Avg. Book Equity (2)(incl. AFUDC)	8.88%	0.89%	0.106			

Financial Risk/Credit Quality Metrics	2023	2022	2021	2020	2019	5-Year Average
Permanent Capitalization Ratios						
Long-Term Debt	50.1%	51.0%	53.0%	48.2%	45.2%	49.5%
Preferred Stock	1.0%	2.2%	2.3%	1.8%	1.9%	1.8%
Common Equity (2)	48.9%	46.9%	44.8%	50.0%	52.8%	48.7%
Total Permanent Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Total Capitalization Ratios

Total Debt (incl. CMD and STD)	55.0%	57.6%	59.2%	52.2%	50.9%	55.0%
Preferred Stock	0.9%	1.9%	2.1%	1.6%	1.7%	1.6%
Common Equity (2)	44.1%	40.5%	38.7%	46.1%	47.4%	43.4%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

EBITDA Interest Coverage (3)

EBITDA Interest Cov. (incl. AFUDC deduction)	5.50	6.93	8.16	7.54	6.67	6.96

FFO to Adjusted Total Debt (4)

FFO to Adj. Debt (incl. AFUDC deduction)	14.6%	12.8%	13.2%	16.9%	17.2%	14.9%

- (1) All comparative risk metrics for the Gas LDC Group represent the arithmetic average of the calculated results for each of the individual companies within the Group.
- (2) Excludes the Other Comprehensive Income (Loss) component of Stockholders' Equity.
- (3) Earnings before interest, taxes, depreciation and amortization, divided by interest expense.
- (4) Funds from Operations (net income, plus depreciation, amortization and deferred income taxes) divided by Adjusted Total Debt (total debt, including current maturities and short-term debt, plus post-retirement obligations recognized within the balance sheet).

Source: 10-K filings of the proxy group companies.

Capital Structure Ratios - Permanent Capitalization
Gas LDC Group - 2019-2023 and 5-Year Average

Exhibit VVR-2

Page 3 of 4

	2023	2022	2021	2020	2019	5-Year Average
<u>Atmos Energy Corp.</u>						
Long-Term Debt	39.1%	38.9%	38.6%	39.8%	37.6%	38.8%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	60.9%	61.1%	61.4%	60.2%	62.4%	61.2%
Total Permanent Capitalizatio	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>NiSource Inc.</u>						
Long-Term Debt	52.1%	54.5%	55.4%	60.6%	56.4%	55.8%
Preferred Stock	2.3%	8.9%	9.3%	5.8%	6.3%	0.07
Common Equity (1)	45.6%	36.6%	35.3%	33.6%	37.3%	37.7%
Total Permanent Capitalizatio	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>Northwest Natural Gas Co.</u>						
Long-Term Debt	52.5%	51.3%	52.5%	48.8%	47.9%	50.6%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	47.5%	48.7%	47.5%	51.2%	52.1%	49.4%
Total Permanent Capitalizatio	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>ONE Gas, Inc.</u>						
Long-Term Debt	43.8%	50.7%	61.0%	41.4%	37.6%	46.9%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	56.2%	49.3%	39.0%	58.6%	62.4%	53.1%
Total Permanent Capitalizatio	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>Southwest Gas Holdings, Inc.</u>						
Long-Term Debt	57.9%	58.7%	57.8%	50.0%	47.3%	54.3%
Preferred Stock	0.0%	0.0%	0.0%	0.0%	0.0%	-
Common Equity (1)	42.1%	41.3%	42.2%	50.0%	52.7%	45.7%
Total Permanent Capitalizatio	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>Spire, Inc.</u>						
Long-Term Debt	55.3%	51.6%	52.5%	48.6%	44.7%	50.6%
Preferred Stock	3.8%	4.2%	4.3%	4.9%	5.2%	4.5%
Common Equity (1)	40.9%	44.1%	43.1%	46.6%	50.1%	45.0%
Total Permanent Capitalizatio	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>Average of Gas LDC Proxy Group</u>						
Long-Term Debt	50.1%	51.0%	53.0%	48.2%	45.2%	49.5%
Preferred Stock	1.0%	2.2%	2.3%	1.8%	1.9%	1.8%
Common Equity (1)	48.9%	46.9%	44.8%	50.0%	52.8%	48.7%
Total Permanent Capitalizatio	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

(1) Excludes Other Comprehensive Income (Loss) component of Stockholders' Equity.

Capital Structure Ratios - Total Capitalization
Gas LDC Group - 2019-2023 and 5-Year Average

Exhibit VVR-2

Page 4 of 4

	2023	2022	2021	2020	2019	5-Year Average
<u>Atmos Energy Corp.</u>						
Total Debt (incl. CM and STI)	39.9%	47.4%	48.3%	39.8%	40.5%	43.2%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	60.1%	52.6%	51.7%	60.2%	59.5%	56.8%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>NiSource Inc.</u>						
Total Debt (incl. CM and STI)	58.1%	58.8%	57.0%	61.9%	61.3%	59.4%
Preferred Stock	2.0%	8.0%	9.0%	5.6%	5.6%	6.0%
Common Equity (1)	39.9%	33.2%	34.0%	32.5%	33.1%	34.5%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>Northwest Natural Gas Co.</u>						
Total Debt (incl. CM and STI)	56.3%	57.4%	60.2%	58.3%	54.0%	57.2%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	43.7%	42.6%	39.8%	41.7%	46.0%	42.8%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>ONE Gas, Inc.</u>						
Total Debt (incl. CM and STI)	52.4%	55.6%	63.9%	47.2%	45.8%	53.0%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	47.6%	44.4%	36.1%	52.8%	54.2%	47.0%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>Southwest Gas Holdings</u>						
Total Debt (incl. CM and STI)	61.2%	65.9%	67.8%	51.3%	51.1%	59.5%
Preferred Stock	-	-	-	-	-	-
Common Equity (1)	38.8%	34.1%	32.2%	48.7%	48.9%	40.5%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>Spire, Inc.</u>						
Total Debt (incl. CM and STI)	61.9%	60.7%	58.0%	55.0%	52.7%	57.7%
Preferred Stock	3.2%	3.4%	3.8%	4.3%	4.5%	3.8%
Common Equity (1)	34.9%	35.9%	38.2%	40.8%	42.9%	38.5%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%
<u>Average of Gas LDC Proxy Group</u>						
Total Debt (incl. CM and STI)	55.0%	57.6%	59.2%	52.2%	50.9%	55.0%
Preferred Stock	0.9%	1.9%	2.1%	1.6%	1.7%	1.6%
Common Equity (1)	44.1%	40.5%	38.7%	46.1%	47.4%	43.4%
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

(1) Excludes Other Comprehensive Income (Loss) component of Stockholders' Equity.

Abbreviations: "CM" denotes Current Maturities of Debt; "STD" denotes Short-Term Debt.

Regulatory Mechanisms by Jurisdiction
Atmos Energy Corp.

Jurisdiction	Rate / Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
CO	-	System Safety and Integrity Rider (SSIR)
KS	Weather Normalization (WNA)	Gas System Reliability Surcharge (GSRS) and System Integrity Program (SIP)
KY	Weather Normalization (WNA)	Pipeline Replacement Program (PRP)
LA	WNA and Rate Stabilization Clause (RSC)	Safety and Reliability Deferral Mechanism (SIIP)
MS	WNA and Stable Rate Filing (SRF)	System Integrity Rider (SIR)
TN	WNA and Annual Rate Mechanism (ARM)	Infrastructure Deferral Mechanism
TX (Mid)	WNA and Rate Review Mechanism	Rule 8.209 System Safety and Reliability Capital Deferral Mechanism and Gas Reliability Infrastructure Program (GRIP)
TX (West)	WNA and Rate Review Mechanism	Rule 8.209 System Safety and Reliability Capital Deferral Mechanism and Gas Reliability Infrastructure Program (GRIP)
VA	Weather Normalization (WNA)	Steps to Advance Virginia Energy (SAVE)

(1) Rate/revenue stabilization mechanisms include the following four rate design approaches: (a) revenue decoupling mechanisms (incl. lost revenues adjustment); (b) weather normalization adjustment (WNA) clauses; (c) straight-fixed variable (SFV) or modified fixed-variable (MFV) rate design; and (d) rate stabilization tariffs.

Source of Data: Company 10-K reports and investor conference presentations.

Regulatory Mechanisms by Jurisdiction
NiSource Inc.

Jurisdiction	Rate / Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
IN	Fixed Customer Charge (Gas)	Transmission, Distribution and Storage System Improvement Charge (TDSIC) (Gas and Electric)
KY	Weather Normalization Adjustment (WNA) and Fixed Customer Charge	Safety Modernization and Repl. Program (SMRP)
MD	Weather Normalization Adjustment (WNA) and Revenue Normalization Adjustment (RNA)	Strategic Infrastructure Development and Enhancement (STRIDE)
OH	Straight-Fixed Variable Rate Design	Capital Expenditure Program (CEP) and Infrastructure Replacement Program (IRP)
PA	Weather Normalization Adjustment (WNA) and Fixed Customer Charge	Distribution and Storage System Impr. Charge (DSIC)
VA	Weather Normalization Adjustment (WNA) and Revenue Normalization Adjustment (RNA)	Steps to Advance Virginia's Energy Plan (SAVE)

Regulatory Mechanisms by Jurisdiction
Northwest Natural Gas Co.

Jurisdiction	Rate / Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
OR	Revenue Decoupling & WNA (WARM)	Forward Test Year
WA	-	Forward Test Tear (Multiyear)

- (1) Rate/revenue stabilization mechanisms include the following four rate design approaches: (a) revenue decoupling mechanisms (incl. lost revenues adjustment); (b) weather normalization adjustment (WNA) clauses; (c) straight-fixed variable (SFV) or modified fixed-variable (MFV) rate design; and (d) rate stabilization tariffs.

Source of Data: Company 10-K reports and investor conference presentations.

Regulatory Mechanisms by Jurisdiction
ONE Gas, Inc.

Jurisdiction	Rate / Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
KS	Weather Normalization Adjustment (WNA)	Gas System Reliability Surcharge (GSRS)
OK	WNA (Temperature Adjustment Clause)	PBRC - Incremental Capital Investment
TX	Weather Normalization Adjustment (WNA)	Gas Reliability Infrastructure Program (GRIP) and Cost of Service Adjustment (COSA)

Regulatory Mechanisms by Jurisdiction
Southwest Gas Corp.

Jurisdiction	Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
AZ	Decoupling (Delivery Charge Adjustment Mech.)	Customer Owned Yard Line (COYL) Program & Vintage Steel Pipe Replacement (VSP) Program
CA	Decoupling (Fixed Cost Adjustment Mech.)	Targeted Pipe Replacement Program and COYL program.
NV	Decoupling (General Revenues Adjustment Mech.)	Gas Infrastructure Replacement Program (GIR)

Regulatory Mechanisms by Jurisdiction
Spire Inc.

Jurisdiction	Rate / Revenue Stabilization Mechanisms (1)	Infrastructure Replacement Cost Recovery Mechanisms
AL	WNA (Temperature Adjustment Rider) and Rate Stabilization & Equalization (RSE)	-
MO	Weather Normalization (WNA)	Infrastructure System Replacement Surcharge (ISRS)
MS	WNA and Rate Stabilization Adjustment (RSA)	Supplemental Growth Rider (SG)

- (1) Rate/revenue stabilization mechanisms include the following four rate design approaches: (a) revenue decoupling mechanisms (incl. lost revenues adjustment); (b) weather normalization adjustment (WNA) clauses; (c) straight-fixed variable (SFV) or modified fixed-variable (MFV) rate design; and (d) rate stabilization tariffs.

Source of Data: Company 10-K reports and investor conference presentations.

Columbia Gas of Pennsylvania, Inc.

Summary Cost of Capital

December 31, 2026

<u>Line No.</u>	<u>Type of Capital</u>	<u>Ratios</u>	<u>Cost Rate</u>	<u>Weighted Cost Rate</u>
1	Long-Term Debt	43.28%	5.22%	2.26%
2	Short Term Debt	<u>2.32%</u>	5.00%	<u>0.12%</u>
3	Total Debt	45.60%		2.38%
4	Common Equity	<u>54.40%</u>	<u>11.35%</u>	<u>6.17%</u>
5	Total	<u>100.00%</u>		<u>8.55%</u>

Columbia Gas of Pennsylvania, Inc.

Investor-provided Capitalization

Actual at November 30, 2024, Estimated at November 30, 2025, and Estimated at December 31, 2026

<u>Line No.</u>		<u>Actual at November 30, 2024</u>		<u>Estimate at November 30, 2025</u>		<u>Estimate at December 31, 2026</u>	
		<u>Amount</u>	<u>Ratios</u>	<u>Amount</u>	<u>Ratios</u>	<u>Amount</u>	<u>Ratios</u>
		<u>Outstanding</u>		<u>Outstanding</u>		<u>Outstanding</u>	
1	Long Term Debt	<u>\$ 1,385,515,000</u>	43.25%	<u>\$ 1,371,000,000</u>	40.17%	<u>\$ 1,691,000,000</u>	43.28%
	Common Stock Equity						
2	Common Stock	45,127,800		45,127,800		45,127,800	
3	Additional Paid in Capital	192,889,827		192,889,827		192,889,827	
4	Retained Earnings	<u>1,491,342,462</u>		<u>1,682,836,630</u>		<u>1,887,292,250</u>	
5	Total Common Equity	<u>1,729,360,089</u>	53.98%	<u>1,920,854,257</u>	56.28%	<u>2,125,309,877</u>	54.40%
6	Total Permanent Capital	3,114,875,089		3,291,854,257		3,816,309,877	
7	Short Term Debt (12-Month Avg)	<u>88,936,541</u>	<u>2.78%</u>	<u>121,364,242</u>	<u>3.56%</u>	<u>90,581,073</u>	<u>2.32%</u>
8	Total Capital Employed	<u><u>\$ 3,203,811,631</u></u>	<u><u>100.00%</u></u>	<u><u>\$ 3,413,218,499</u></u>	<u><u>100.00%</u></u>	<u><u>\$ 3,906,890,949</u></u>	<u><u>100.00%</u></u>

Columbia Gas of Pennsylvania, Inc.
Debt Outstanding as of November 30, 2024

Line No.	Date of Issuance	Coupon Rate	Amount Outstanding	Annualized Debt Services	Embedded Cost of Debt
1	November 28, 2005	5.920%	\$ 54,515,000	\$ 3,227,288	
2	December 14, 2007	6.865%	58,000,000	3,981,700	
3	December 16, 2010	6.020%	28,000,000	1,685,600	
4	March 28, 2012	5.355%	30,000,000	1,606,500	
5	March 28, 2012	5.890%	35,000,000	2,061,500	
6	November 28, 2012	5.260%	65,000,000	3,419,000	
7	June 19, 2013	5.530%	23,000,000	1,271,900	
8	December 18, 2013	6.290%	32,000,000	2,012,800	
9	December 18, 2014	4.430%	30,000,000	1,329,000	
10	March 24, 2015	4.150%	60,000,000	2,490,000	
11	September 28, 2015	4.505%	60,000,000	2,703,060	
12	March 31, 2016	4.186%	45,000,000	1,883,610	
13	January 31, 2017	4.439%	85,000,000	3,772,810	
14	June 29, 2018	4.528%	80,000,000	3,622,320	
15	November 22, 2019	3.687%	80,000,000	2,949,600	
16	March 31, 2020	3.872%	110,000,000	4,258,760	
17	March 31, 2021	3.652%	110,000,000	4,017,310	
18	December 31, 2021	3.267%	50,000,000	1,633,550	
19	June 30, 2022	5.081%	40,000,000	2,032,320	
20	December 30, 2022	5.650%	60,000,000	3,389,880	
21	June 30, 2023	5.563%	40,000,000	2,225,120	
22	September 29, 2023	6.262%	110,000,000	6,887,980	
23	June 28, 2024	5.912%	50,000,000	2,956,200	
24	September 30, 2024	5.376%	50,000,000	2,688,100	
25	Total Long-Term Debt		1,385,515,000	68,105,908	4.92%
26	Short Term Debt (12-Month Average)	5.5367%	88,936,541	4,924,120	
27	Total Debt		<u>\$ 1,474,451,541</u>	<u>\$ 73,030,028</u>	4.95%

Columbia Gas of Pennsylvania, Inc.
Estimated Debt Outstanding as of November 30, 2025

<u>Line No.</u>	<u>Date of Issuance</u>	<u>Coupon Rate</u>	<u>Amount Outstanding</u>	<u>Annualized Debt Services</u>	<u>Embedded Cost of Debt</u>
1	December 14, 2007	6.865%	\$ 58,000,000	\$ 3,981,700	
2	December 16, 2010	6.020%	28,000,000	1,685,600	
3	March 28, 2012	5.355%	30,000,000	1,606,500	
4	March 28, 2012	5.890%	35,000,000	2,061,500	
5	November 28, 2012	5.260%	65,000,000	3,419,000	
6	June 19, 2013	5.530%	23,000,000	1,271,900	
7	December 18, 2013	6.290%	32,000,000	2,012,800	
8	December 18, 2014	4.430%	30,000,000	1,329,000	
9	March 24, 2015	4.150%	60,000,000	2,490,000	
10	September 28, 2015	4.505%	60,000,000	2,703,060	
11	March 31, 2016	4.186%	45,000,000	1,883,610	
12	January 31, 2017	4.439%	85,000,000	3,772,810	
13	June 29, 2018	4.528%	80,000,000	3,622,320	
14	November 22, 2019	3.687%	80,000,000	2,949,600	
15	March 31, 2020	3.872%	110,000,000	4,258,760	
16	March 31, 2021	3.652%	110,000,000	4,017,310	
17	December 31, 2021	3.267%	50,000,000	1,633,550	
18	June 30, 2022	5.081%	40,000,000	2,032,320	
19	December 30, 2022	5.650%	60,000,000	3,389,880	
20	June 30, 2023	5.563%	40,000,000	2,225,120	
21	September 29, 2023	6.262%	110,000,000	6,887,980	
22	June 28, 2024	5.912%	50,000,000	2,956,200	
23	September 30, 2024	5.376%	50,000,000	2,688,100	
24	June 30, 2025	6.500%	40,000,000	2,600,000	
25	Total Long-Term Debt		1,371,000,000	67,478,620	4.92%
26	Short Term Debt (12-Month Average)	5.0000%	121,364,242	6,068,212	
27	Total Debt		<u>\$ 1,492,364,242</u>	<u>\$ 73,546,832</u>	4.93%

Columbia Gas of Pennsylvania, Inc.**Estimated Debt Outstanding as of December 31, 2026**

Line No.	Date of Issuance	Coupon Rate	Amount Outstanding	Annualized Debt Services	Embedded Cost of Debt
1	December 14, 2007	6.865%	\$ 58,000,000	\$ 3,981,700	
2	December 16, 2010	6.020%	28,000,000	1,685,600	
3	March 28, 2012	5.355%	30,000,000	1,606,500	
4	March 28, 2012	5.890%	35,000,000	2,061,500	
5	November 28, 2012	5.260%	65,000,000	3,419,000	
6	June 19, 2013	5.530%	23,000,000	1,271,900	
7	December 18, 2013	6.290%	32,000,000	2,012,800	
8	December 18, 2014	4.430%	30,000,000	1,329,000	
9	March 24, 2015	4.150%	60,000,000	2,490,000	
10	September 28, 2015	4.505%	60,000,000	2,703,060	
11	March 31, 2016	4.186%	45,000,000	1,883,610	
12	January 31, 2017	4.439%	85,000,000	3,772,810	
13	June 29, 2018	4.528%	80,000,000	3,622,320	
14	November 22, 2019	3.687%	80,000,000	2,949,600	
15	March 31, 2020	3.872%	110,000,000	4,258,760	
16	March 31, 2021	3.652%	110,000,000	4,017,310	
17	December 31, 2021	3.267%	50,000,000	1,633,550	
18	June 30, 2022	5.081%	40,000,000	2,032,320	
19	December 30, 2022	5.650%	60,000,000	3,389,880	
20	June 30, 2023	5.563%	40,000,000	2,225,120	
21	September 29, 2023	6.262%	110,000,000	6,887,980	
22	June 28, 2024	5.912%	50,000,000	2,956,200	
23	September 30, 2024	5.376%	50,000,000	2,688,100	
24	June 30, 2025	6.500%	40,000,000	2,600,000	
25	December 31, 2025	6.500%	155,000,000	10,075,000	
26	December 31, 2026	6.500%	165,000,000	10,725,000	
27	Total Long-Term Debt		1,691,000,000	88,278,620	5.22%
28	Short Term Debt (12-Month Average)	5.0000%	90,581,073	4,529,054	
29	Total Debt		<u>\$ 1,781,581,073</u>	<u>\$ 92,807,674</u>	5.21%

DCF Method
Gas LDC Group
Projected Growth Rates and Cost of Equity Estimates

Exhibit VVR-7
Page 1 of 7

	(1)	(2)	(3)	(4)	(5)	(5)	(5)
	Dividend Yield	S&P Global EPS Growth	Zacks EPS Growth	Value Line EPS Growth	S&P Global EPS COE	Zacks EPS COE	Value Line EPS COE
Gas LDC Group							
Atmos Energy Corp	2.5%	7.5%	7.0%	7.0%	10.0%	9.5%	9.5%
NiSource Inc.	3.1%	7.8%	7.5%	9.5%	10.9%	10.5%	12.6%
Northwest Natural Gas Co.	4.8%	4.8%	n/a	6.5%	9.7%	n/a	11.3%
ONE Gas, Inc.	3.7%	2.5%	2.9%	3.5%	6.2%	6.6%	7.2%
Southwest Gas Holdings, Inc.	3.4%	8.2%	6.5%	10.0%	11.6%	9.9%	13.4%
Spire Inc.	4.7%	6.5%	5.8%	4.5%	11.2%	10.5%	9.2%
Average (6)	3.7%	6.2%	5.9%	6.8%	10.7%	10.1%	10.5%

<u>Low-End and High-End Outlier Tests</u>							
Low-End Threshold (7.00%) (6)					7.00%	7.00%	7.00%
Median Result (excluding negative values)(6)					10.4%	9.9%	10.4%
200% of Median Result (6)					20.9%	19.8%	20.8%
High-End Threshold - 200% of Median (average)					20.5%	20.5%	20.5%

- (1) See page 3 of this Exhibit.
- (2) S&P Global Market Intelligence (retrieved January 13, 2025).
- (3) www.zacks.com (retrieved January 13, 2025).
- (4) See page 5 of this Exhibit.
- (5) Sum of dividend yield and applicable projected growth rate.
- (6) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 7.00% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% of the median value of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates). See page 6 of this Exhibit and FERC Opinion No. 569, 169 FERC ¶, 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P.140 (Nov. 19, 2020). FERC's previous high-end outlier test of 17.7% was further applied where indicated (see ISO New England Inc., 109 FERC ¶ 61,147 at P 205 (November 3, 2004).

DCF Method
Gas LDC Group
Historical EPS Growth Rates and Cost of Equity Estimates

Exhibit VVR-7

Page 2 of 7

	(1)	(2)	(3)	(4)	(5)
	Dividend Yield	5-Year Historical EPS Growth	10-Year Historical EPS Growth	Average Historical EPS Growth	Cost of Equity - Hist. EPS
Gas LDC Group					
Atmos Energy Corp.	2.5%	9.0%	9.5%	9.3%	11.8%
NiSource Inc.	3.1%	15.0%	1.5%	8.3%	11.3%
Northwest Natural Gas Co.	4.8%	2.5%	-1.0%	0.8%	5.6%
ONE Gas, Inc.	3.7%	6.0%	n/a	6.0%	9.7%
Southwest Gas Holdings, Inc.	3.4%	4.5%	5.5%	5.0%	8.4%
Spire Inc.	4.7%	3.0%	5.0%	4.0%	8.7%
Average (6)	3.7%	6.7%	4.1%	5.5%	10.0%

<u>Low-End and High-End Outlier Tests</u>	
Low-End Threshold (7.00%) (6)	7.00%
Median Result (excluding negative values)(6)	9.2%
200% of Median Result (6)	18.4%
High-End Threshold - 200% of Median (average)	18.4%

(1) See page 3 of this Exhibit.

(2) See page 5 of this Exhibit.

(3) See page 5 of this Exhibit.

(4) Average of (2) and (3) above. If either the 10-year or 5-year historical EPS growth rate is either negative or unavailable, only the positive or available EPS growth rate has been referenced.

(5) Sum of (1) and (4) above.

(6) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 7.00% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% higher than the average of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates). See page 6 of this Exhibit and FERC Opinion No. 569, 169 FERC ¶ 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P.140 (Nov. 19, 2020).

DCF Method
Gas LDC Group
Dividend Yield Calculations

Exhibit VVR-7
Page 3 of 7

	(a)	(b)	(b)/(a)
Gas LDC Group	30/60/90 Day Stock Price Avg.	Next 12-Mo. Dividends	Dividend Yield
Atmos Energy Corp.	\$ 141.15	\$ 3.54	2.5%
NiSource Inc.	\$ 36.12	\$ 1.11	3.1%
Northwest Natural Gas Co.	\$ 40.59	\$ 1.96	4.8%
ONE Gas, Inc.	\$ 71.87	\$ 2.68	3.7%
Southwest Gas Holdings, Inc.	\$ 73.21	\$ 2.50	3.4%
Spire Inc.	\$ 67.51	\$ 3.16	4.7%
Average	-	-	3.7%

(a) See page 4 of this Exhibit; 30/60/90 day average closing stock price.

(b) Value Line Investment Survey, Summary and Index, January 17, 2025. Estimated dividends, next twelve months.

Averages		Atmos Energy		NiSource Inc.		Northwest Natural Gas		ONE Gas, Inc.		Southwest Gas Holdings, Inc.		Spire Inc.
30-Day Average	\$	140.55	\$	36.57	\$	40.54	\$	70.63	\$	72.27	\$	68.26
60-Day Average	\$	142.25	\$	36.25	\$	40.77	\$	72.49	\$	73.82	\$	67.38
90-Day Average	\$	140.64	\$	35.54	\$	40.46	\$	72.48	\$	73.55	\$	66.89
30/60/90 Day Avg.	\$	141.15	\$	36.12	\$	40.59	\$	71.87	\$	73.21	\$	67.51

Date		Atmos Energy		NiSource Inc.		Northwest Natural Gas		ONE Gas, Inc.		Southwest Gas Holdings, Inc.		Spire Inc.
14-Jan-25		140.72		36.73		39.44		69.90		69.84		67.44
13-Jan-25		138.26		36.34		38.72		69.26		69.36		66.29
10-Jan-25		137.04		36.03		38.31		67.93		68.42		65.62
8-Jan-25		139.52		36.45		39.17		68.35		70.34		67.39
7-Jan-25		136.63		35.77		38.58		68.05		70.76		66.50
6-Jan-25		136.51		35.57		38.69		67.77		70.20		66.24
3-Jan-25		138.79		36.39		39.69		69.02		71.34		68.56
2-Jan-25		138.29		36.36		39.52		68.37		70.31		68.40
31-Dec-24		139.27		36.76		39.56		69.25		70.71		67.83
30-Dec-24		138.93		36.70		39.37		69.36		70.23		67.46
27-Dec-24		139.36		36.76		39.48		69.56		70.35		67.12
26-Dec-24		140.00		36.85		39.76		69.94		70.41		67.53
24-Dec-24		140.06		36.86		39.68		69.98		70.52		67.11
23-Dec-24		139.20		36.44		39.50		69.29		69.55		66.65
20-Dec-24		139.69		36.17		39.57		68.72		69.65		66.69
19-Dec-24		137.97		35.87		39.61		68.06		69.57		65.55
18-Dec-24		136.41		35.43		39.21		66.96		67.87		64.46
17-Dec-24		141.38		36.21		41.03		70.50		70.83		68.30
16-Dec-24		140.45		36.34		41.29		70.50		72.20		67.89
13-Dec-24		140.58		36.55		41.81		70.38		72.85		67.70
12-Dec-24		140.22		36.53		41.57		70.21		74.18		68.11
11-Dec-24		140.03		36.76		41.84		71.15		75.14		68.71
10-Dec-24		141.11		36.61		41.97		71.69		74.78		70.13
9-Dec-24		141.05		36.61		41.76		72.35		75.13		69.87
6-Dec-24		141.96		37.06		41.90		72.62		75.63		70.42
5-Dec-24		143.04		37.28		42.30		74.04		76.48		70.76
4-Dec-24		144.00		37.25		42.93		74.92		77.04		71.80
3-Dec-24		146.03		37.06		42.94		75.93		78.00		71.72
2-Dec-24		148.56		37.35		43.26		76.78		78.16		72.43
29-Nov-24		151.32		38.09		43.82		77.97		78.16		73.19
27-Nov-24		151.43		38.25		43.34		77.59		78.30		73.11
26-Nov-24		150.33		38.25		43.29		76.99		78.07		72.60
25-Nov-24		150.18		37.95		43.85		78.69		79.16		73.38
22-Nov-24		150.05		37.71		43.78		77.87		77.51		72.55
21-Nov-24		150.26		37.85		43.21		76.88		77.47		70.66
20-Nov-24		147.22		37.30		42.12		76.04		76.26		68.39
19-Nov-24		146.78		37.11		41.84		76.47		79.11		67.93
18-Nov-24		146.97		36.81		41.61		76.58		77.43		68.19
15-Nov-24		144.89		36.57		41.15		75.40		76.49		67.01
14-Nov-24		144.34		36.02		40.63		74.19		76.28		65.92
13-Nov-24		146.51		36.25		41.29		75.09		76.64		65.69
12-Nov-24		146.82		35.95		41.63		75.30		77.62		66.15
11-Nov-24		146.11		36.22		41.44		75.02		77.10		66.08
8-Nov-24		144.19		35.97		40.88		73.34		75.01		64.42
7-Nov-24		141.44		35.00		40.36		72.81		73.38		63.94
6-Nov-24		138.88		35.16		40.91		74.34		73.65		65.09
5-Nov-24		137.98		35.23		39.10		70.53		73.63		62.80
4-Nov-24		137.67		34.74		38.42		69.97		71.84		62.24
1-Nov-24		138.40		34.49		38.51		70.04		72.05		62.51
31-Oct-24		138.78		35.16		38.89		71.27		73.25		63.86
30-Oct-24		139.62		35.13		40.00		72.20		73.59		64.48
29-Oct-24		140.45		34.42		40.00		72.88		73.10		64.51
28-Oct-24		141.49		35.14		40.41		73.69		74.70		65.27
25-Oct-24		140.72		34.82		39.96		73.06		73.56		64.83
24-Oct-24		142.67		35.26		40.33		73.60		74.37		65.62
23-Oct-24		143.11		35.31		40.56		73.76		74.30		65.83
22-Oct-24		141.92		34.77		40.55		73.70		74.05		66.39
21-Oct-24		142.21		34.93		40.49		73.87		73.65		66.25
18-Oct-24		143.26		35.14		40.67		74.76		74.52		65.25
17-Oct-24		143.76		34.96		40.55		74.48		74.96		63.78
16-Oct-24		143.94		35.10		41.22		74.25		76.59		66.80
15-Oct-24		142.00		34.49		40.55		72.85		75.10		65.56
14-Oct-24		140.28		34.22		40.25		72.35		74.42		65.26
11-Oct-24		139.36		33.93		39.84		71.71		74.33		64.87
10-Oct-24		138.20		33.74		39.00		70.80		72.83		63.90
9-Oct-24		138.04		33.99		39.25		71.36		72.77		64.35
8-Oct-24		138.23		34.12		38.84		71.60		73.85		64.49
7-Oct-24		137.66		34.02		38.88		72.05		73.80		64.25
4-Oct-24		139.84		34.64		39.52		73.43		73.83		65.12
3-Oct-24		139.22		34.69		39.12		72.73		72.69		65.03
2-Oct-24		139.12		34.68		39.67		72.94		73.45		65.69
1-Oct-24		138.98		34.83		40.40		73.93		73.57		66.93
30-Sep-24		138.71		34.65		40.82		74.42		73.76		67.29
27-Sep-24		137.78		34.38		40.46		74.20		74.52		67.14
26-Sep-24		136.77		34.12		40.08		73.70		73.78		66.34
25-Sep-24		136.58		34.18		40.03		73.97		75.02		66.78
24-Sep-24		136.48		34.25		40.00		74.24		73.87		66.79
23-Sep-24		137.35		34.27		39.95		74.29		74.68		67.10
20-Sep-24		136.56		34.08		39.48		73.54		73.94		66.56
19-Sep-24		136.25		33.83		40.01		73.64		74.24		66.77
18-Sep-24		136.53		34.07		40.06		73.31		73.41		66.80
17-Sep-24		138.15		34.18		40.49		73.52		73.76		66.92
16-Sep-24		138.27		34.38		40.61		73.81		73.04		66.95
13-Sep-24		136.97		34.06		40.33		72.66		72.27		66.28
12-Sep-24		134.77		33.63		39.30		71.16		69.91		65.01
11-Sep-24		134.78		33.56		39.05		70.70		69.59		64.77
10-Sep-24		136.20		33.51		39.50		69.99		70.56		66.91
9-Sep-24		133.80		33.45		38.94		68.74		68.16		65.74
6-Sep-24		130.80		33.20		39.22		68.58		68.49		65.54
5-Sep-24		131.42		33.40		40.05		69.74		70.11		65.96

DCF Method
Gas LDC Group
Per Share Annual Growth Rates - Historical and Projected

Exhibit VVR-7
Page 5 of 7

Gas LDC Group	Past 5-Years Historical Growth Rates				Estimated '21-'23 to '27-'29 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Atmos Energy Corp.	9.0%	8.5%	12.0%	9.8%	7.0%	7.5%	5.0%	6.5%
NiSource Inc.	15.0%	3.5%	0.5%	6.3%	9.5%	4.5%	5.0%	6.3%
Northwest Natural Gas Co.	2.5%	0.5%	0.5%	1.2%	6.5%	0.5%	4.0%	3.7%
ONE Gas, Inc.	6.0%	8.5%	4.5%	6.3%	3.5%	2.5%	4.5%	3.5%
Southwest Gas Holdings, Inc.	4.5%	7.0%	7.0%	6.2%	10.0%	5.5%	7.5%	7.7%
Spire Inc.	3.0%	5.5%	3.5%	4.0%	4.5%	4.5%	5.5%	4.8%
Average	6.7%	5.6%	4.7%	5.6%	6.8%	4.2%	5.3%	5.4%

Gas LDC Group	Past 10-Years Historical Growth Rates			
	EPS	DPS	BVPS	Average
Atmos Energy Corp.	9.5%	7.0%	9.5%	8.7%
NiSource Inc.	1.5%	-0.5%	-3.0%	-0.7%
Northwest Natural Gas Co.	-1.0%	1.5%	1.0%	0.5%
ONE Gas, Inc.	n/a	n/a	n/a	n/a
Southwest Gas Holdings, Inc.	5.5%	8.5%	6.5%	6.8%
Spire Inc.	5.0%	5.0%	5.5%	5.2%
Average	4.1%	4.3%	3.9%	4.1%

Source: Value Line Investment Survey, Ratings & Reports, November 22, 2024.

Recent Average between Moody's "A" Rated and "Baa" Rated 30-Year Utility Bond Yield (1)	5.61%
Market Risk Premium per CAPM Analysis (2)	7.00%
20% Weighting Factor per FERC Opinion No. 569 (3)	20.0%
Equity Risk Premium Factor to Apply to "A"/"Baa" Rated Bond Yield (3)(4)	1.40%
Low-End Outlier Threshold (3)(5)	7.01%

Footnotes:

- (1) Q4, 2024 average of "A" rated and "Baa" rated utility bond yields (Mergent Bond Record, January 2025).
- (2) See Mr. Rea's CAPM analysis (Exhibit VVR-11, p. 1).
- (3) See FERC Opinion No. 569, 169 FERC ¶ 61,129, at P. 387-389 (Nov. 21, 2019), and FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.161-162 (May 21, 2020).
- (4) Product of (2) x (3) above.
- (5) Sum of (1) and (4) above. Rounded to 7.00 percent for purposes of Mr. Rea's DCF analyses.

Gas LDC Group	Value Line Risk Indicators					Long-Term Credit Ratings				Market Cap	
	Beta	Safety Rank	Financial Strength	Fin. Str. Weight	Stk Price Stability	S&P LT Rating	S&P Weight	Moody's LT Rating	Moody's Weight	Source: Value Line Billions (\$)	
Atmos Energy Corp.	0.90	1	A	3	95	A-	7	A1	5	\$	22.70
NiSource Inc.	0.95	2	A	3	95	BBB+	8	Baa2	9		16.90
Northwest Natural Gas Co.	0.90	2	A	3	85	A-	7	Baa1	8		1.60
ONE Gas, Inc.	0.85	2	B++	4	85	A-	7	A3	7		4.30
Southwest Gas Holdings, Inc.	0.95	2	A	3	80	BBB-	10	Baa2	9		5.50
Spire Inc.	0.90	2	B++	4	90	BBB+	8	Baa2	9		3.80
Averages	0.91	2	A	3	88	BBB+	8	Baa1	8	\$	9.13

Source: Value Line Investment Survey, Ratings & Reports, November 22, 2024 and Value Line Summary & Index, January 17, 2025. S&P and Moody's long-term credit ratings accessed January 20, 2025

S&P Credit Rating Weightings		Moody's Credit Rating Weightings		Value Line Fin. Str. Weightings	
AAA	1	Aaa	1	A++	1
AA+	2	Aa1	2	A+	2
AA	3	Aa2	3	A	3
AA-	4	Aa3	4	B++	4
A+	5	A1	5	B+	5
A	6	A2	6	B	6
A-	7	A3	7	C++	7
BBB+	8	Baa1	8	C+	8
BBB	9	Baa2	9	C	9
BBB-	10	Baa3	10		
BB+	11	Ba1	11		
BB	12	Ba2	12		
BB-	13	Ba3	13		

DCF Method
Combination Utility Group
Projected Growth Rates and Cost of Equity Estimates

Exhibit VVR-8
Page 1 of 6

	(1)	(2)	(3)	(4)	(5)	(5)	(5)
	Dividend	S&P	Zacks	Value Line	S&P	Zacks	Value Line
	Yield	Global	EPS	EPS	Global	EPS	EPS
		EPS Growth	Growth	Growth	EPS COE	COE	COE
Combination Utility Group							
Alliant Energy Corp.	3.2%	6.9%	6.6%	6.0%	10.1%	9.8%	9.2%
Avista Corp.	5.1%	5.3%	5.4%	5.5%	10.4%	10.5%	10.6%
Black Hills Corp.	4.5%	4.5%	3.4%	4.0%	8.9%	7.9%	8.5%
CMS Energy Corp.	3.0%	7.4%	7.5%	6.0%	10.4%	10.6%	9.0%
Consolidated Edison, Inc.	3.5%	5.6%	5.6%	6.0%	9.2%	9.1%	9.5%
Eversource Energy	4.9%	5.6%	5.5%	6.0%	10.5%	10.4%	10.9%
MGE Energy, Inc.	1.9%	n/a	n/a	7.0%	n/a	n/a	8.9%
Northwestern Energy Group	4.9%	5.4%	6.1%	4.5%	10.4%	11.1%	9.4%
Sempra Energy	3.0%	6.6%	7.7%	6.0%	9.6%	10.6%	9.0%
WEC Energy Group	3.5%	7.2%	7.6%	6.0%	10.7%	11.0%	9.5%
Average (6)	3.8%	6.0%	6.1%	5.7%	10.0%	10.1%	9.5%

Low-End and High-End Outlier Tests							
Low-End Threshold (7.00%) (6)					7.00%	7.00%	7.00%
Median Result (excluding negative values)(6)					10.4%	10.5%	9.3%
200% of Median Result (6)					20.7%	20.9%	18.6%
High-End Threshold - 200% of Median (average)					20.1%	20.1%	20.1%

(1) See page 3 of this Exhibit.

(2) S&P Global Market Intelligence (retrieved January 13, 2025).

(3) www.zacks.com (retrieved January 13, 2025).

(4) See page 5 of this Exhibit.

(5) Sum of dividend yield and applicable projected growth rate.

(6) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 7.00% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% of the median value of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates). See page 6 of Exhibit VVR-7 and FERC Opinion No. 569, 169 FERC ¶ 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P.140 (Nov. 19, 2020). FERC's previous high-end outlier test of 17.7% was further applied where indicated (see ISO New England Inc., 109 FERC ¶ 61,147 at P 205 (November 3, 2004)).

DCF Method
Combination Utility Group
Historical EPS Growth Rates and Cost of Equity Estimates

Exhibit VVR-8
Page 2 of 6

	(1)	(2)	(3)	(4)	(5)
Combination Utility Group	Dividend Yield	5-Year Historical EPS Growth	10-Year Historical EPS Growth	Average Historical EPS Growth	Cost of Equity - Hist. EPS
Alliant Energy Corp.	3.2%	7.0%	6.0%	6.5%	9.7%
Avista Corp.	5.1%	1.0%	3.0%	2.0%	7.1%
Black Hills Corp.	4.5%	4.0%	5.5%	4.8%	9.2%
CMS Energy Corp.	3.0%	5.5%	6.0%	5.8%	8.8%
Consolidated Edison, Inc.	3.5%	2.0%	2.0%	2.0%	5.5%
Eversource Energy	4.9%	5.5%	6.5%	6.0%	10.9%
MGE Energy, Inc.	1.9%	6.5%	5.0%	5.8%	7.6%
Northwestern Energy Group	4.9%	n/a	3.5%	3.5%	8.4%
Sempra Energy	3.0%	13.5%	7.5%	10.5%	13.5%
WEC Energy Group	3.5%	7.0%	6.5%	6.8%	10.2%
Average (6)	3.8%	5.8%	5.2%	5.4%	9.5%

<u>Low-End and High-End Outlier Tests</u>	
Low-End Threshold (7.00%) (6)	7.00%
Median Result (excluding negative values)(6)	9.0%
200% of Median Result (6)	18.0%
High-End Threshold - 200% of Median (average)	18.0%

(1) See page 3 of this Exhibit.

(2) See page 5 of this Exhibit.

(3) See page 5 of this Exhibit.

(4) Average of (2) and (3) above.

(5) Sum of (1) and (4) above.

(6) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 7.00% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% of the median value of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates).

See page 6 of Exhibit VVR-7 and FERC Opinion No. 569, 169 FERC ¶ 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P. 154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P. 140 (Nov. 19, 2020). FERC's previous high-end outlier test of 17.7% was further applied where indicated (see ISO New England Inc., 109 FERC ¶ 61,147 at P 205 (November 3, 2004).

DCF Method
Combination Utility Group
Dividend Yield Calculation

Exhibit VVR-8

Page 3 of 6

	(a)	(b)	(b)/(a)
Combination Utility Group	30/60/90 Day Avg. Stock Price	Next 12-Mo. Dividends	Dividend Yield
Alliant Energy Corp.	\$ 59.92	\$ 1.92	3.2%
Avista Corp.	\$ 37.17	\$ 1.90	5.1%
Black Hills Corp.	\$ 60.07	\$ 2.70	4.5%
CMS Energy Corp.	\$ 67.87	\$ 2.06	3.0%
Consolidated Edison, Inc.	\$ 95.49	\$ 3.38	3.5%
Eversource Energy	\$ 60.76	\$ 2.99	4.9%
MGE Energy, Inc.	\$ 95.95	\$ 1.80	1.9%
Northwestern Energy Group	\$ 53.67	\$ 2.64	4.9%
Sempra Energy	\$ 86.98	\$ 2.58	3.0%
WEC Energy Group	\$ 96.14	\$ 3.34	3.5%
Average			3.8%

(a) See page 4 of this Exhibit; 30/60/90 day average closing stock price.

(b) Value Line Investment Survey, Summary and Index, January 17, 2025. Estimated dividends during the next 12-months.

30-Day Average	\$	59.57	\$	36.64	\$	59.42	\$	66.79	\$	91.62	\$	58.45	\$	96.11	\$	52.70	\$	87.02	\$	95.38
60-Day Average	\$	60.11	\$	37.29	\$	60.40	\$	68.09	\$	96.19	\$	61.01	\$	96.99	\$	53.80	\$	87.79	\$	96.76
90-Day Average	\$	60.06	\$	37.59	\$	60.39	\$	68.71	\$	98.67	\$	62.83	\$	94.75	\$	54.51	\$	86.14	\$	96.29
30/60/90 Day Avg.	\$	59.92	\$	37.17	\$	60.07	\$	67.87	\$	95.49	\$	60.76	\$	95.95	\$	53.67	\$	86.98	\$	96.14

Date	Alliant Energy Corp.	Avista Corp.	Black Hills Corp.	CMS Energy Corp.	Consolidated Edison, Inc.	Eversource Energy	MGE Energy	Northwestern Energy Grp.	Sempra Energy	WEC Energy Group
14-Jan-25	57.79	35.94	56.50	65.56	89.37	55.98	91.14	52.28	78.11	94.58
13-Jan-25	56.98	35.35	55.96	64.99	88.47	55.86	89.50	51.53	76.94	93.89
10-Jan-25	56.66	35.20	55.74	65.09	88.15	55.63	88.24	51.11	78.73	93.41
8-Jan-25	58.20	36.54	56.21	66.30	89.01	56.72	91.20	52.46	82.82	94.75
7-Jan-25	57.36	36.04	56.19	65.71	88.00	56.08	91.03	51.94	84.23	93.19
6-Jan-25	57.31	35.24	56.42	65.42	88.37	56.23	90.36	51.68	84.51	92.12
3-Jan-25	58.34	36.59	57.79	66.61	89.24	57.31	93.36	53.14	87.67	93.79
2-Jan-25	58.51	36.35	58.11	66.53	89.03	57.34	92.96	52.99	87.13	93.99
31-Dec-24	59.14	36.63	58.52	66.65	89.23	57.43	93.96	53.46	87.72	94.04
30-Dec-24	59.33	36.67	58.39	66.63	89.16	57.30	94.38	53.55	87.35	94.21
27-Dec-24	59.54	36.53	58.55	67.06	89.56	57.32	95.09	53.00	87.77	94.82
26-Dec-24	59.65	36.83	58.98	66.95	89.59	57.34	95.44	53.45	87.61	94.87
24-Dec-24	59.62	36.66	58.98	66.82	89.58	57.28	95.25	53.18	87.96	95.04
23-Dec-24	59.26	36.52	58.44	66.67	89.67	57.18	94.11	52.74	87.04	94.84
20-Dec-24	58.95	36.19	57.97	66.61	90.03	56.95	94.46	52.60	86.81	94.50
19-Dec-24	58.26	35.86	58.05	65.76	89.07	55.90	93.94	52.50	85.90	93.26
18-Dec-24	58.15	35.46	57.73	65.85	88.87	56.16	92.89	50.44	85.09	92.94
17-Dec-24	59.57	36.74	60.06	67.04	90.84	58.51	95.75	52.25	86.96	94.71
16-Dec-24	59.88	36.51	60.78	66.70	91.26	58.13	96.33	50.80	88.63	94.93
13-Dec-24	60.45	36.71	60.96	67.32	92.69	59.52	97.75	50.93	89.16	95.74
12-Dec-24	60.47	36.48	60.98	67.03	92.61	59.79	98.40	51.58	87.93	95.86
11-Dec-24	60.41	36.66	61.00	66.82	92.75	59.99	101.28	52.26	87.41	95.61
10-Dec-24	60.70	37.21	61.38	67.66	94.69	60.54	99.47	52.80	88.55	97.15
9-Dec-24	60.91	37.42	61.38	67.65	94.78	60.25	99.78	53.01	88.78	97.11
6-Dec-24	61.06	37.25	61.92	67.17	94.82	59.78	100.35	53.43	89.60	97.09
5-Dec-24	61.54	37.37	62.77	67.38	96.50	61.64	100.92	53.80	90.94	97.72
4-Dec-24	61.78	37.51	63.01	67.50	96.62	61.79	102.74	54.02	91.50	98.35
3-Dec-24	61.83	37.99	63.00	68.25	97.53	61.31	104.07	54.39	92.01	98.22
2-Dec-24	62.28	38.06	62.81	68.40	98.50	63.67	104.91	54.45	92.10	99.66
29-Nov-24	63.20	38.69	64.07	69.71	100.59	64.49	104.28	55.24	93.67	101.05
27-Nov-24	63.59	38.60	63.94	70.49	101.58	64.59	104.76	54.72	94.28	101.82
26-Nov-24	63.34	38.54	63.59	70.45	101.70	63.58	103.34	54.48	93.29	101.55
25-Nov-24	63.63	39.23	64.66	69.67	99.47	63.98	104.75	57.05	94.77	101.35
22-Nov-24	63.32	39.13	64.31	69.52	98.36	63.38	104.14	56.75	94.27	100.66
21-Nov-24	63.20	39.04	63.29	69.21	98.70	62.75	104.13	56.51	94.69	100.96
20-Nov-24	62.23	38.52	62.43	68.52	97.88	61.61	103.89	55.57	93.12	99.27
19-Nov-24	62.25	38.77	62.71	68.57	96.97	61.67	104.53	55.66	93.38	99.05
18-Nov-24	61.81	38.64	62.96	68.50	96.45	62.07	104.97	55.59	92.92	99.28
15-Nov-24	60.98	37.75	62.74	68.23	96.44	61.85	104.86	55.19	92.19	97.98
14-Nov-24	59.50	37.19	62.68	67.41	95.24	61.48	105.70	54.85	90.44	96.13
13-Nov-24	60.14	37.47	63.16	67.69	95.41	60.84	108.16	55.27	92.19	97.63
12-Nov-24	59.93	37.68	61.77	68.10	97.04	60.57	106.87	55.19	92.20	97.85
11-Nov-24	59.92	37.93	62.38	68.60	98.48	61.09	106.20	54.99	92.12	98.70
8-Nov-24	57.75	37.32	60.78	67.25	98.13	61.40	101.52	54.22	91.25	97.59
7-Nov-24	56.24	36.55	59.57	66.36	97.58	60.82	97.36	53.41	89.76	95.33
6-Nov-24	57.00	37.42	60.36	67.86	98.96	60.70	97.32	54.59	88.26	96.01
5-Nov-24	58.12	37.23	58.81	69.11	99.82	62.07	90.81	53.21	82.25	96.10
4-Nov-24	57.51	36.40	57.60	68.39	99.15	63.40	89.10	52.58	80.81	94.91
1-Nov-24	57.74	36.70	57.92	68.30	100.00	63.67	88.55	52.79	81.65	95.57
31-Oct-24	60.00	37.48	59.19	69.61	101.68	65.85	90.49	53.46	83.37	95.53
30-Oct-24	59.28	37.60	59.57	70.11	102.72	65.49	90.09	53.91	83.55	96.03
29-Oct-24	59.70	37.69	59.95	69.52	102.91	64.55	90.20	53.55	83.55	95.33
28-Oct-24	61.14	38.19	60.35	71.16	104.81	66.49	91.69	55.34	85.17	97.00
25-Oct-24	60.74	37.78	59.87	70.76	104.60	65.84	90.68	54.48	84.38	97.19
24-Oct-24	61.91	38.36	60.42	71.77	107.00	66.82	91.79	55.10	85.77	98.81
23-Oct-24	61.92	38.46	61.07	72.10	107.40	67.09	91.46	55.31	85.96	99.53
22-Oct-24	61.04	38.54	60.87	71.03	105.70	66.23	90.82	55.00	85.01	98.69
21-Oct-24	61.36	37.93	60.62	71.17	106.26	66.13	92.17	55.32	84.93	99.43
18-Oct-24	62.17	37.98	61.76	71.29	106.76	66.13	93.21	56.47	85.96	99.85
17-Oct-24	61.98	37.89	61.85	71.01	105.66	65.00	92.54	56.46	85.49	99.14
16-Oct-24	62.29	38.53	62.04	71.17	106.14	65.75	94.47	56.99	85.66	98.75
15-Oct-24	61.08	38.30	60.91	70.30	105.45	65.40	91.90	56.39	84.03	97.22
14-Oct-24	60.38	37.98	60.45	69.87	103.04	64.02	90.70	55.60	83.15	96.30
11-Oct-24	59.67	37.59	59.31	69.34	102.32	63.82	90.52	55.11	82.16	95.45
10-Oct-24	58.98	37.19	58.81	69.14	101.58	63.86	89.66	54.49	81.33	93.95
9-Oct-24	59.56	37.41	59.17	69.62	102.37	63.39	90.02	54.56	81.52	94.31
8-Oct-24	59.59	37.25	59.39	69.97	102.11	63.72	88.92	54.73	81.61	94.35
7-Oct-24	59.34	37.18	59.12	69.77	101.14	64.08	89.34	54.63	81.51	94.14
4-Oct-24	60.19	37.88	59.95	71.22	103.15	65.38	90.95	55.77	82.60	95.48
3-Oct-24	60.57	37.72	59.99	71.14	104.02	65.89	91.06	55.95	82.53	96.31
2-Oct-24	60.59	38.03	60.51	71.25	104.45	66.68	91.24	56.41	83.38	96.26
1-Oct-24	61.02	38.65	60.87	71.05	105.15	67.73	91.83	57.24	83.92	96.75
30-Sep-24	60.69	38.75	61.12	70.63	104.13	68.05	91.45	57.22	83.63	96.18
27-Sep-24	60.74	38.72	61.05	70.43	104.05	67.52	91.03	57.27	83.25	95.26
26-Sep-24	59.90	38.19	60.65	69.95	103.12	65.99	90.06	56.82	81.94	94.61
25-Sep-24	59.95	38.54	60.93	69.83	103.16	66.13	90.52	56.93	83.00	94.60
24-Sep-24	60.05	38.23	61.14	70.08	102.82	66.52	91.94	56.85	83.02	94.54
23-Sep-24	60.35	38.62	61.53	70.29	104.02	66.53	92.42	57.03	84.04	95.18
20-Sep-24	59.72	38.31	60.68	69.84	103.35	67.14	91.47	56.47	83.18	94.72
19-Sep-24	59.75	38.34	60.85	69.23	102.12	67.20	90.70	56.85	82.51	93.78
18-Sep-24	60.33	38.70	60.88	70.00	103.41	67.49	90.83	56.54	82.94	95.24
17-Sep-24	60.31	38.81	61.15	70.26	104.54	68.23	91.58	56.67	83.95	95.74
16-Sep-24	60.51	38.97	61.09	70.48	104.85	68.40	91.78	56.52	83.60	96.14
13-Sep-24	59.65	38.54	60.55	70.09	104.56	67.97	90.60	55.94	82.97	95.85
12-Sep-24	58.91	37.63	59.39	69.31	103.39	67.50	88.00	55.46	81.70	95.01
11-Sep-24	59.00	37.80	59.57	69.23	103.82	67.79	87.29	54.58	81.37	95.21
10-Sep-24	59.35	38.63	60.35	69.51	104.97	68.00	87.83	55.19	82.08	95.55
9-Sep-24	59.25	38.28	59.61	69.12	104.75	68.06	86.68	54.54	82.94	94.86
6-Sep-24	58.58	38.41	59.66	68.01	103.28	67.40	86.40	54.21	82.10	93.65
5-Sep-24	58.97	38.95	60.13	68.31	103.79	68.05	87.11	54.61	83.09	94.68
90-Day Average	60.06	37.59	60.39	68.71	98.67	62.83	94.75	54.51	86.14	96.29

Combination Utility Group	Past 5-Years Historical Growth Rates				Estimated '21-'23 to '27-'29 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Alliant Energy Corp.	7.0%	6.5%	6.5%	6.7%	6.0%	6.0%	4.0%	5.3%
Avista Corp.	1.0%	4.5%	3.5%	3.0%	5.5%	4.0%	2.0%	3.8%
Black Hills Corp.	4.0%	6.0%	6.5%	5.5%	4.0%	4.0%	3.5%	3.8%
CMS Energy Corp.	5.5%	6.5%	8.0%	6.7%	6.0%	5.0%	5.0%	5.3%
Consolidated Edison, Inc.	2.0%	2.5%	3.5%	2.7%	6.0%	4.0%	4.5%	4.8%
Eversource Energy	5.5%	6.0%	4.0%	5.2%	6.0%	6.0%	3.0%	5.0%
MGE Energy, Inc.	6.5%	4.5%	6.0%	5.7%	7.0%	6.5%	5.5%	6.3%
Northwestern Energy Group	n/a	3.5%	4.0%	3.8%	4.5%	1.5%	3.0%	3.0%
Sempra Energy	13.5%	7.0%	10.0%	10.2%	6.0%	6.0%	6.0%	6.0%
WEC Energy Group	7.0%	6.5%	3.5%	5.7%	6.0%	7.0%	4.0%	5.7%
Average	5.8%	5.4%	5.6%	5.5%	5.7%	5.0%	4.1%	4.9%

Combination Utility Group	Past 10-Years Historical Growth Rates			
	EPS	DPS	BVPS	Average
Alliant Energy Corp.	6.0%	6.5%	6.0%	6.2%
Avista Corp.	3.0%	4.5%	4.0%	3.8%
Black Hills Corp.	5.5%	5.0%	5.0%	5.2%
CMS Energy Corp.	6.0%	7.0%	6.5%	6.5%
Consolidated Edison, Inc.	2.0%	2.5%	4.0%	2.8%
Eversource Energy	6.5%	7.0%	4.5%	6.0%
MGE Energy, Inc.	5.0%	4.5%	6.0%	5.2%
Northwestern Energy Group	3.5%	5.5%	6.0%	5.0%
Sempra Energy	7.5%	7.0%	7.0%	7.2%
WEC Energy Group	6.5%	10.0%	7.0%	7.8%
Average	5.2%	6.0%	5.6%	5.6%

Combination Utility Group	Value Line Risk Indicators					Long-Term Credit Ratings				Market Cap
	Beta	Safety Rank	Financial Strength	Fin. Str. Weight	Stk Price Stability	S&P LT Rating	S&P Weight	Moody's LT Rating	Moody's Weight	Billions (\$) per Value Line
Alliant Energy Corp. (LNT)	0.90	1	A+	2	90	A-	7	Baa2	9	16.30
Avista Corp.	0.95	3	A	3	70	BBB	9	Baa2	9	2.80
Black Hills Corp. (BKH)	1.05	2	A	3	80	BBB+	8	Baa2	9	4.00
CMS Energy Corp. (CMS)	0.85	2	B++	4	95	BBB+	8	Baa2	9	20.80
Consolidated Edison, Inc. (ED)	0.80	1	A+	2	90	A-	7	Baa1	8	36.30
Eversource Energy (ES)	0.95	2	A	3	80	A-	7	Baa2	9	23.80
MGE Energy Inc.	0.85	3	B++	4	70	AA-	4	A1	5	3.80
Northwestern Energy Group	1.00	2	B++	4	90	BBB	9	Baa2	9	3.40
Sempra Energy (SRE)	1.00	2	A	3	90	BBB+	8	Baa2	9	53.50
WEC Energy Group (WEC)	0.85	1	A+	2	90	A-	7	Baa1	8	29.40
Averages	0.92	2	A	3	85	A-	7	Baa1	8	19.41

Source: Value Line Investment Survey, January 17, 2025, December 6, 2024, and November 8, 2024. S&P and Moody's ratings accessed on January 20, 2025.

S&P Credit Rating Weightings		Moody's Credit Rating Weightings		Value Line Fin. Str. Weightings	
AAA	1	Aaa	1	A++	1
AA+	2	Aa1	2	A+	2
AA	3	Aa2	3	A	3
AA-	4	Aa3	4	B++	4
A+	5	A1	5	B+	5
A	6	A2	6	B	6
A-	7	A3	7	C++	7
BBB+	8	Baa1	8	C+	8
BBB	9	Baa2	9	C	9
BBB-	10	Baa3	10		
BB+	11	Ba1	11		
BB	12	Ba2	12		
BB-	13	Ba3	13		

DCF Method
Non-Regulated Group
Projected Growth Rates and Cost of Equity Estimates

Exhibit VVR-9

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		(1)	(2)	(3)	(4)	(5)	(5)	(5)
			Projected Growth Rates			Cost of Equity (COE)		
			S&P		Value Line	S&P		
		Dividend	Global	Zacks	EPS	Global	Zacks	Value Line
Non-Regulated Group	Ticker	Yield	EPS Growth	EPS Growth	Growth	EPS COE	EPS COE	EPS COE
Air Products and Chemicals, Inc.	APD	2.3%	12.0%	7.8%	10.5%	14.3%	10.1%	12.8%
Brown-Forman Corporation	BFB	2.4%	4.5%	n/a	14.0%	6.9%	n/a	16.4%
Coca-Cola Co.	KO	3.2%	5.6%	6.2%	7.0%	8.8%	9.3%	10.2%
Home Depot, Inc.	HD	2.2%	3.8%	6.3%	6.5%	6.0%	8.5%	8.7%
IDEX Corporation	IEX	1.3%	12.0%	12.0%	5.0%	13.3%	13.3%	6.3%
Illinois Tool Works	ITW	2.3%	5.7%	6.8%	9.0%	7.9%	9.1%	11.3%
McDonald's Corp.	MCD	2.4%	5.7%	6.2%	8.5%	8.1%	8.6%	10.9%
Mondelez International	MDLZ	2.9%	3.5%	5.6%	7.5%	6.4%	8.5%	10.4%
Republic Services, Inc.	RSG	1.1%	10.2%	10.2%	11.0%	11.3%	11.3%	12.1%
Average (6)		2.2%	7.0%	7.6%	8.8%	10.6%	9.8%	11.6%
Low-End and High-End Outlier Tests								
Low-End Threshold (7.00%) (7)						7.00%	7.00%	7.00%
Median Result (excluding negative values)(7)						8.1%	9.2%	10.9%
200% of Median Result (7)						16.1%	18.4%	21.8%
High-End Threshold - 200% of Median (average)						18.8%	18.8%	18.8%

(1) See page 3 of this Exhibit.

(2) S&P Global Market Intelligence (retrieved January 13, 2025).

(3) www.zacks.com (retrieved January 13, 2025).

(4) Value Line Investment Survey, Ratings and Reports, January 24, 2025, January 10, 2025, January 3, 2025, December 13, 2024 and November 15, 2024.

(5) Sum of dividend yield and applicable projected growth rate.

(6) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 7.00% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% of the median value of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates). See page 6 of Exhibit 4 and FERC Opinion No. 569, 169 FERC ¶ 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P.140 (Nov. 19, 2020). FERC's previous high-end outlier test of 17.7% was further applied where indicated (see ISO New England Inc., 109 FERC ¶ 61,147 at P 205 (November 3, 2004)).

DCF Method
Non-Regulated Group
Historical EPS Growth Rates and Cost of Equity Estimates

Exhibit VVR-9
Page 2 of 5

	(1)	(2)	(3)	(4)	(5)
	Dividend Yield	5-Year Historical EPS Growth	10-Year Historical EPS Growth	Average Historical EPS Growth	Cost of Equity Historical EPS Growth
Non-Regulated Group					
Air Products and Chemicals, Inc.	2.3%	8.0%	6.5%	7.3%	9.6%
Brown-Forman Corporation	2.4%	3.5%	5.5%	4.5%	6.9%
Coca-Cola Co.	3.2%	5.0%	2.5%	3.8%	6.9%
Home Depot, Inc.	2.2%	14.5%	17.5%	16.0%	18.2%
IDEX Corporation	1.3%	10.0%	10.0%	10.0%	11.3%
Illinois Tool Works	2.3%	6.5%	9.0%	7.8%	10.0%
McDonald's Corp.	2.4%	8.0%	5.5%	6.8%	9.2%
Mondelez International	2.9%	6.0%	5.0%	5.5%	8.4%
Republic Services, Inc.	1.1%	13.5%	10.0%	11.8%	12.9%
Average (6)	2.2%	8.3%	7.9%	8.1%	10.2%

<u>Low-End and High-End Outlier Tests</u>	
Low-End Threshold (7.00%) (6)	7.00%
Median Result (excluding negative values)(6)	9.6%
200% of Median Result (6)	19.1%
High-End Threshold - 200% of Median (average)	19.1%

(1) See page 3 of this Exhibit.

(2) Value Line Investment Survey, Ratings and Reports, January 24, 2025, January 10, 2025, January 3, 2025, December 13, 2024 and November 15, 2024.

(3) See (2) above.

(4) Average of (2) and (3) above.

(5) Sum of (1) and (4) above, which is the sum of the dividend yield and the average historical earnings growth rate.

(6) For cost of equity estimates, the average calculations exclude the highlighted data. DCF estimates below 7.00% were excluded from the estimated cost of equity. Also excluded were DCF results that were more than 200% of the median value of the DCF results for the entire proxy group prior to the elimination of any outlier results (with the exception of negative estimates). See page 6 of Exhibit VVR-7 and FERC Opinion No. 569, 169 FERC ¶ 61,129, at P. 387 (Nov. 21, 2019), FERC Opinion No. 569-A, 171 FERC ¶ 61,154, at P.154 (May 21, 2020), and FERC Opinion No. 569-B, 173 FERC ¶ 61,159, at P.140 (Nov. 19, 2020). FERC's previous high-end outlier test of 17.7% was further applied where indicated (see ISO New England Inc.,

DCF Method
Non-Regulated Group
Dividend Yield Calculations

Exhibit VVR-9

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Non-Regulated Group	Ticker	Dividend Next 12-Months (1)	30/60/90 Day Stock Price Average	Dividend Yield
Air Products and Chemicals, Inc.	APD	7.08	307.47	2.3%
Brown-Forman Corporation	BFB	1.00	41.49	2.4%
Coca-Cola Co.	KO	2.04	64.15	3.2%
Home Depot, Inc.	HD	9.00	403.76	2.2%
IDEX Corporation	IEX	2.90	217.30	1.3%
Illinois Tool Works	ITW	6.00	262.83	2.3%
McDonald's Corp.	MCD	7.08	295.07	2.4%
Mondelez International	MDLZ	1.88	63.92	2.9%
Republic Services, Inc.	RSG	2.32	206.98	1.1%
Average				2.2%

(1) Source: Value Line Investment Survey, Summary and Index, January 17, 2025

Averages	Air Products	Brown Forman	Coca-Cola	Home Depot	IDEX Corp.	Illinois Tool Works	McDonald's Corp.	Mondelez International	Republic Services
30-Day Average	\$ 303.78	\$ 39.90	\$ 62.47	\$ 404.39	\$ 217.61	\$ 262.51	\$ 293.06	\$ 60.64	\$ 207.42
60-Day Average	\$ 312.19	\$ 41.49	\$ 63.80	\$ 405.11	\$ 219.15	\$ 264.42	\$ 295.36	\$ 63.99	\$ 207.51
90-Day Average	\$ 306.44	\$ 43.08	\$ 66.18	\$ 401.78	\$ 215.15	\$ 261.58	\$ 296.79	\$ 67.12	\$ 206.01
30/60/90 Day Avg.	\$ 307.47	\$ 41.49	\$ 64.15	\$ 403.76	\$ 217.30	\$ 262.83	\$ 295.07	\$ 63.92	\$ 206.98

Date	Air Products	Brown Forman	Coca-Cola	Home Depot	IDEX Corp.	Illinois Tool Works	McDonald's Corp.	Mondelez International	Republic Services
14-Jan-25	307.96	34.29	62.04	392.78	214.54	252.97	281.58	57.10	207.00
13-Jan-25	301.74	34.30	61.65	389.18	210.03	249.70	283.63	56.17	207.22
10-Jan-25	293.08	33.67	61.07	389.89	206.02	244.90	282.31	56.25	206.29
8-Jan-25	285.25	35.47	61.71	387.20	208.79	247.61	286.90	58.29	206.96
7-Jan-25	286.33	35.83	60.84	384.23	208.00	248.59	289.34	58.29	203.05
6-Jan-25	283.24	36.39	60.81	389.37	209.32	250.36	292.18	58.22	200.95
3-Jan-25	283.91	35.94	61.75	389.18	207.02	252.29	294.78	59.86	201.04
2-Jan-25	283.29	36.81	61.84	388.46	206.06	250.03	292.51	59.50	200.09
31-Dec-24	290.04	37.69	62.26	388.99	209.29	253.56	289.89	59.73	201.18
30-Dec-24	288.69	37.56	62.03	389.43	208.83	254.83	289.60	59.56	201.19
27-Dec-24	292.81	38.20	62.45	392.86	211.11	256.55	293.62	60.21	202.88
26-Dec-24	295.08	38.99	62.57	395.14	212.98	258.77	294.80	59.85	204.10
24-Dec-24	296.02	39.17	62.84	396.14	212.28	259.17	293.99	60.00	204.14
23-Dec-24	293.55	39.58	62.38	392.45	210.76	257.64	291.29	59.28	202.26
20-Dec-24	294.99	40.44	62.55	392.60	212.38	258.82	292.68	59.39	203.73
19-Dec-24	293.17	40.63	62.45	385.02	210.26	258.11	290.23	59.27	203.95
18-Dec-24	295.31	40.64	62.85	393.82	211.65	261.23	290.88	60.02	203.46
17-Dec-24	304.71	42.01	63.40	408.47	222.19	267.88	296.08	61.34	205.62
16-Dec-24	306.72	43.18	62.55	410.71	224.08	269.66	297.71	61.49	208.14
13-Dec-24	312.30	44.50	63.12	416.98	223.00	272.11	296.60	61.93	208.97
12-Dec-24	310.89	44.58	63.84	414.42	224.98	273.12	296.63	62.63	210.13
11-Dec-24	312.36	44.22	62.64	421.38	228.17	272.96	296.10	63.12	210.35
10-Dec-24	315.21	44.73	62.91	422.59	227.95	273.75	300.71	61.75	211.69
9-Dec-24	316.62	44.97	62.60	429.18	229.65	274.07	301.37	61.44	212.34
6-Dec-24	320.11	43.97	62.53	431.37	229.71	273.53	298.98	62.86	216.68
5-Dec-24	321.97	45.11	62.92	426.54	228.45	275.27	299.47	63.24	215.48
4-Dec-24	327.48	40.40	62.21	427.92	227.87	275.90	295.09	63.27	215.55
3-Dec-24	330.64	40.89	63.52	429.35	230.50	275.99	294.50	64.81	214.79
2-Dec-24	335.62	41.61	63.65	426.96	231.81	278.50	292.44	65.23	214.96
29-Nov-24	334.33	41.36	64.08	429.13	230.63	277.52	296.01	64.95	218.30
27-Nov-24	333.22	41.10	64.43	427.19	231.10	276.04	295.08	65.06	218.28
26-Nov-24	334.78	40.87	64.55	429.52	232.02	276.51	296.33	64.88	218.75
25-Nov-24	333.97	41.91	64.38	428.67	236.06	276.37	296.19	64.94	217.86
22-Nov-24	331.83	41.03	63.92	420.00	232.50	273.95	290.28	64.40	216.79
21-Nov-24	328.88	40.15	63.76	410.45	227.45	269.85	288.47	64.79	214.06
20-Nov-24	327.85	39.76	62.99	400.00	223.11	266.38	290.91	64.42	212.62
19-Nov-24	328.00	39.38	62.59	406.80	223.61	266.46	290.73	63.87	210.91
18-Nov-24	327.89	39.86	61.86	410.44	226.66	270.06	291.10	63.84	209.08
15-Nov-24	317.10	39.97	61.74	408.18	227.83	270.62	292.63	64.49	208.04
14-Nov-24	315.88	40.18	62.55	405.72	229.39	269.87	298.56	65.56	209.46
13-Nov-24	312.89	39.68	63.00	410.19	231.00	272.96	297.35	66.00	214.68
12-Nov-24	311.12	39.90	63.20	403.08	227.97	271.20	298.65	66.52	212.24
11-Nov-24	313.91	40.07	63.36	408.29	229.34	274.27	301.53	66.10	211.82

Non-Regulated Group	Value Line Risk Indicators						Long-Term Credit Ratings				Market Cap.
	Beta	Safety Rank	Financial Strength	Fin. Str. Weight	Stk Price Stability	Percent % Debt/Cap.	S&P LT Rating	S&P Weight	Moody's LT Rating	Moody's Weight	Billions (\$) Value Line
Air Products and Chemicals, Inc.	0.90	1	A++	1	85	44.0%	A	6	A2	6	\$ 71.2
Brown-Forman Corporation	0.90	1	A	3	90	32.0%	A-	7	A1	5	\$ 17.8
Coca-Cola Co.	0.85	1	A+	2	100	62.0%	A+	5	A1	5	\$ 267.0
Home Depot, Inc.	0.95	1	A++	1	95	90.0%	A	6	A2	6	\$ 424.0
IDEX Corporation	0.95	1	A	3	100	27.0%	BBB	9	Baa2	9	\$ 16.0
Illinois Tool Works	1.00	1	A+	2	95	66.0%	A+	5	A1	5	\$ 76.1
McDonald's Corp.	0.95	1	A++	1	100	100.0%	BBB+	8	Baa1	8	\$ 210.0
Mondelez International, Inc.	0.80	1	A+	2	100	37.0%	BBB	9	Baa1	8	\$ 80.0
Republic Services, Inc.	0.85	1	A	3	100	52.0%	BBB+	8	Baa1	8	\$ 62.8
Averages	0.91	1	A+	2	96	56.7%	A-	7	A3	7	\$ 136.1

S&P Credit Rating Weightings		Moody's Credit Rating Weightings		Value Line Fin. Str. Weightings	
AAA	1	Aaa	1	A++	1
AA+	2	Aa1	2	A+	2
AA	3	Aa2	3	A	3
AA-	4	Aa3	4	B++	4
A+	5	A1	5	B+	5
A	6	A2	6	B	6
A-	7	A3	7	C++	7
BBB+	8	Baa1	8	C+	8
BBB	9	Baa2	9	C	9
BBB-	10	Baa3	10		
BB+	11	Ba1	11		
BB	12	Ba2	12		
BB-	13	Ba3	13		

(4) Value Line Investment Survey, Ratings and Reports, January 24, 2025, January 10, 2025, January 3, 2025, December 13, 2024 and November 15, 2024.

Capital Structure Ratios - Book vs. Market Capitalization Ratios for Leverage Calculations
Gas LDC Group - 12/31/2023 or Fiscal Year End

Exhibit VVR-10

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	[Source is 10-K]		[Source is 10-K and Yahoo Finance]			
	Carrying Values (Book Value)		Market Values (Fair Value)		Common Shares	Closing Stock
\$ in thousands	Dollars	Percentage	Dollars	Percentage	Outstanding at	Price at
	2023	2023	2023	2023	Fiscal Y/E	Fiscal Y/E
<u>Atmos Energy Corp.</u>						
Long-Term Debt (1)	6,639,211	39.1%	5,481,802	25.8%	@ 9/30/2023	
Preferred Stock	-	-	-	-		
Common Equity (2)	10,351,536	60.9%	15,729,842	74.2%		
Total Permanent Capitalization	\$ 16,990,747	100.0%	\$ 21,211,644	100.0%	148,492.8	\$ 105.93
<u>NiSource Inc.</u>						
Long-Term Debt (1)	11,055,500	52.1%	10,347,100	45.6%	@ 12/31/2023	
Preferred Stock	486,100	2.3%	486,100	2.1%		
Common Equity (2)	9,683,800	45.6%	11,877,984	52.3%		
Total Permanent Capitalization	\$ 21,225,400	100.0%	\$ 22,711,184	100.0%	447,381.7	\$ 26.55
<u>Northwest Natural Gas Co.</u>						
Long-Term Debt (1)	1,425,435	52.5%	1,297,076	47.0%	@ 12/31/2023	
Preferred Stock	-	-	-	-		
Common Equity (2)	1,290,887	47.5%	1,465,359	53.0%		
Total Permanent Capitalization	\$ 2,716,322	100.0%	\$ 2,762,435	100.0%	37,631.2	\$ 38.94
<u>ONE Gas, Inc.</u>						
Long-Term Debt (1)	2,160,401	43.8%	2,027,000	36.0%	@ 12/31/2023	
Preferred Stock	-	-	-	-		
Common Equity (2)	2,767,059	56.2%	3,603,105	64.0%		
Total Permanent Capitalization	\$ 4,927,460	100.0%	\$ 5,630,105	100.0%	56,545.9	\$ 63.72
<u>Southwest Gas Holdings, Inc.</u>						
Long-Term Debt (1)	4,609,838	57.9%	4,328,205	48.8%	@ 12/31/2023	
Preferred Stock	-	-	-	-		
Common Equity (2)	3,353,823	42.1%	4,533,567	51.2%		
Total Permanent Capitalization	\$ 7,963,661	100.0%	\$ 8,861,772	100.0%	71,563.8	\$ 63.35
<u>Spire, Inc.</u>						
Long-Term Debt (1)	3,554,000	55.3%	3,113,600	48.9%	@ 9/30/2023	
Preferred Stock	242,000	3.8%	242,000	3.8%		
Common Equity (2)	2,627,700	40.9%	3,010,056	47.3%		
Total Permanent Capitalization	\$ 6,423,700	100.0%	\$ 6,365,656	100.0%	53,200.0	\$ 56.58
Average Ratios of Gas						
<u>LDC Group</u>						
Long-Term Debt (1)		50.1%		42.0%		
Preferred Stock		1.0%		1.0%		
Common Equity (2)		48.9%		57.0%		
Total Permanent Capitalization		100.0%		100.0%		

(1) Long-term debt balances exclude the current portion of long-term debt and short-term debt. In cases where a company's SEC debt disclosure for fair value vs. carrying value only discloses total debt (including short-term debt and current maturities), the difference between fair value and carrying value was fully applied to the long-term debt balance.

(2) Includes common stock account and retained earnings account; excludes other comprehensive income (loss) and shares in a deferred compensation trust.

CAPM Method
Gas LDC Group - Cost of Equity Estimates

Exhibit VVR-11

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Prospective Market Return

DCF Approach - S&P 500 Index

Dividend Yield (1)	1.43%
Growth Rate (2)	10.83%
DCF Market Return - S&P 500 (3)	12.26%

DCF Approach - Value Line 1,700 Stock Universe

Dividend Yield (4)	2.01%
Growth Rate - (5-Year Horizon Average)(5)	8.70%
DCF Market Return - Value Line 1,700 Stock Universe) (6)	10.71%

Prospective Market Return (Average) (7)	11.48%

Prospective Risk-Free Rate of Return

30- Year Treasury Bond Equal-Weighted Composite Yield - (Q4, 2024 Average and 2025-2029 Average Implied Forward Rate) (8)	4.65%

Prospective Market Risk Premium (Average) (9)	6.83%

Historical Market Risk Premium (Kroll Cost of Capital Navigator)

Historical Average Market Risk Premium (1926-2023) (10)	7.17%

Indicated Market Risk Premium (11)	7.00%

Gas LDC Group Beta Coefficient (12)	0.91

Gas LDC Group Risk Premium (13)	6.37%

Prospective Risk-Free Rate of Return (Average) (8)	4.65%

Traditional CAPM Result (14)	11.02%

Size Premium Adjustment (15)	0.61%

Implied Cost of Equity (CAPM with Size Adjustment) (16)	11.63%

CAPM Method

Gas LDC Group - Cost of Equity Estimates

Exhibit VVR-11

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Empirical CAPM Model (ECAPM)

Prospective Risk-Free Rate of Return (Average) (8)	4.65%
25% Weighting of Market Risk Premium (17)	1.75%
75% Weighting of Beta x Market Risk Premium (18)	4.78%
Implied Cost of Equity (ECAPM Model) (19)	11.18%

Footnotes:

- (1) $D/P = [\$19.81](\text{cash dividends for Q4, 2024}) \times 4 (\text{quarters}) \times (1 + (.5) \text{ growth rate}) / [\$5,850.61]$ (90 trading-day average closing price through January 13, 2025. Source: <https://www.spglobal.com> and <https://www.finance.yahoo.com>).
- (2) Bloomberg Finance L.P. Average long-term consensus earnings growth estimates for the S&P 500 Index (10.83%).
- (3) (1) + (2) above.
- (4) See page 5 of this Exhibit. Median estimated dividend yield for the next 12 months for all dividend paying stocks. Value Line Summary & Index; average estimated dividend yield from 13 consecutive weekly reports (October 25, 2024 - January 17, 2025).
- (5) See page 5 of this Exhibit. The Value Line average median price appreciation potential 3 to 5 years hence is 39.62%. The annual expected price appreciation growth rate based upon the five-year horizon is 8.70% $[(1 + .3962)^{.25} - 1]$.
Source: Value Line Summary & Index; average of 13 consecutive weekly reports (October 25, 2024 - January 17, 2025).
- (6) (4) + (5) above.
- (7) Average of (3) and (6) above. Result may reflect rounding differences.
- (8) Composite rate based on the Q4, 2024 average yield for the 30-year U.S. Treasury bond and the 30-year Treasury average implied forward rate for 2025-2029.
Source: Mergent Bond Record, January 2025 (Volume 90, No. 1, at 407-408; and Bloomberg Finance L.P. (accessed January 14, 2025).
- (9) (7) - (8) above. Result may reflect rounding differences.
- (10) Historical average market (equity) risk premium (1926-2023), as reported by Kroll Cost of Capital Navigator.
- (11) Average of (9) and (10) above. May reflect rounding differences.
- (12) Value Line as-reported average beta coefficient for the Gas LDC Group.
- (13) (11) x (12) above.
- (14) (13) + (8) above.
- (15) Size premium (return in excess of CAPM) for Decile 3 portfolios, as reported by Kroll Cost of Capital Navigator.
- (16) (14) + (15) above.
- (17) (11) above x 25%.
- (18) 75% x (11) above x (12) above.
- (19) (8) + (17) + (18) above.

CAPM Method
Combination Utility Group - Cost of Equity Estimates

Exhibit VVR-11

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Indicated Market Risk Premium (20)	7.00%
Combination Utility Group Beta Coefficient (21)	0.92
Combination Utility Group Risk Premium (22)	6.44%
Prospective Risk-Free Rate of Return (Average) (23)	4.65%
Traditional CAPM Result (24)	11.09%
Size Premium Adjustment (25)	0.46%
Implied Cost of Equity (CAPM with Size Adjustment) (26)	11.55%

Empirical CAPM Model (ECAPM)

Prospective Risk-Free Rate of Return (Average) (23)	4.65%
25% Weighting of Market Risk Premium (27)	1.75%
75% Weighting of Beta x Market Risk Premium (28)	4.83%
Implied Cost of Equity (ECAPM Model) (29)	11.23%

Footnotes:

(20) See pages 1-2 of this Exhibit and footnotes 1-11 therein.

(21) Value Line as-reported average beta coefficient for the Combination Utility Group.

(22) (20) x (21) above.

(23) See pages 1-2 of this Exhibit and footnote 8 therein.

(24) (22) + (23) above.

(25) Size premium (return in excess of CAPM) for Decile 2 portfolios, as reported by Kroll Cost of Capital Navigator.

(26) (24) + (25) above.

(27) (20) above x 25%.

(28) 75% x (21) above x (20) above.

(29) (23) + (27) + (28) above.

CAPM Method
Non-Regulated Group - Cost of Equity Estimates

Exhibit VVR-11

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Indicated Market Risk Premium (30)	7.00%
Non-Regulated Group Beta Coefficient (31)	0.91
Non-Regulated Group Risk Premium (32)	6.37%
Prospective Risk-Free Rate of Return (Average) (33)	4.65%
Traditional CAPM Result (34)	11.02%
Size Premium Adjustment (35)	-0.06%
Implied Cost of Equity (CAPM with Size Adjustment) (36)	10.96%

Empirical CAPM Model (ECAPM)

Prospective Risk-Free Rate of Return (Average) (37)	4.65%
25% Weighting of Market Risk Premium (38)	1.75%
75% Weighting of Beta x Market Risk Premium (39)	4.78%
Implied Cost of Equity (ECAPM Model) (40)	11.18%

Footnotes:

(30) See pages 1-2 of this Exhibit and footnotes 1-11 therein.

(31) Value Line as-reported average beta coefficient for the Non-Regulated Group.

(32) (30) x (31) above.

(33) See pages 1-2 of this Exhibit and footnote 8 therein.

(34) (32) + (33) above.

(35) Size premium (return in excess of CAPM) for Decile 1 portfolios, as reported by Kroll Cost of Capital Navigator.

(36) (34) + (35) above.

(37) See pages 1-2 of this Exhibit and footnote 8 therein.

(38) (30) above x 25%.

(39) 75% x (30) above x (31) above.

(40) (37) + (38) + (39) above.

CAPM Method
Value Line Investment Survey
Median Estimated Dividend Yields and Price Appreciation Potential

Value Line Report Date	Median Estimated Dividend Yields (1)	Median Price Apprec. Potential (2)
1/17/2025	2.10%	45.00%
1/10/2025	2.10%	45.00%
1/3/2025	2.10%	45.00%
12/27/2024	2.00%	40.00%
12/20/2024	2.00%	35.00%
12/13/2024	1.90%	35.00%
12/6/2024	1.90%	35.00%
11/29/2024	2.00%	40.00%
11/22/2024	1.90%	35.00%
11/15/2024	2.10%	40.00%
11/8/2024	2.00%	40.00%
11/1/2024	2.00%	40.00%
10/25/2024	2.00%	40.00%
13-Week Average	2.01%	39.62%

Annual Appreciation Return (3-year realization)	11.77%
Annual Appreciation Return (4-year realization)	8.70%
Annual Appreciation Return (5-year realization)	6.90%

Source: Value Line Investment Survey, Summary & Index. Averages derived from 13 consecutive weekly reports, from October 25, 2024 to January 17, 2025.

(1) The Value Line median of estimated dividend yields (for the next 12 months) of all dividend paying stocks under review.

(2) The Value Line estimated median price appreciation potential of all 1,700 stocks in the hypothesized economic environment, 3 to 5 years hence.

Risk Premium Method (RPM)
Gas LDC Group - Indicated Cost of Equity

Exhibit VVR-12

Page 1 of 10

Prospective "Aaa" Rated Corporate Bond Yield - Composite (1)	5.41%

Yield/Credit Spread Adjustment Between "Aaa" Rated Corporate Bond Yields and "A" Rated Public Utility Bond Yields (2)	0.50%

Prospective "A" Rated Public Utility Bond Yield (3)	5.91%

Yield/Credit Spread Adjustment Between "A" Rated Public Utility Bonds and BBB+/Baa1 Average Rating of the Gas Group (4)	0.15%

Prospective Bond Yield for Gas LDC Group (5)	6.06%

Equity Risk Premium	
- Total Market Index Approach (6)	5.44%
- Public Utility Index Approach (7)	4.85%
Indicated Equity Risk Premium (8)	5.15%

Indicated Cost of Equity - Gas LDC Group (9)	11.20%

- (1) See page 2 of this Exhibit. Composite "Aaa" rated long-term corporate bond yield based on the implied forward rate for the 2025-2029 period and the Q4, 2024 actual average yield for Aaa rated corporate bonds.
- (2) See page 3 of this Exhibit. Yield adjustment derived from historical corporate bond yield data (recent 12 months) found in the Mergent Bond Record.
- (3) Sum of (1) and (2) above.
- (4) Adjustment to reflect credit spread differential between "A" rated public utility bonds and BBB+/ Baa1 rating of the Gas LDC Group, as reflected on page 3 of this Exhibit. The 0.15% adjustment was derived via simple linear interpolation between the yield spread differential for the "Baa" rated and "A" rated public utility bonds, respectively $((5.76\% - 5.54\%)/3*2) = 0.15\%$.
- (5) Sum of (3) and (4) above, subject to rounding.
- (6) See page 4 of this Exhibit.
- (7) See page 5 of this Exhibit.
- (8) Average of (6) and (7) above.
- (9) Sum of (5) and (8) above, subject to rounding.

Risk Premium Method (RPM)
Corporate Bond Implied Forward Rates

Year	"Aaa" Rated Corp. Bonds	"Aaa" Rated Corp. Bonds Average	"Baa" Rated Corp. Bonds	"Baa" Rated Corp. Bonds Average
<u>Recent Historical Spot Rates</u>				
Q4, 2024 Actual (1)	-	5.10%	-	5.74%
<u>Implied Forward Rates - 3-Year and 5-Year Averages</u>				
1/14/2025 (2)	5.61%	-	6.22%	-
12/31/2025 (3)	5.67%	5.64%	6.27%	6.25%
12/31/2026 (3)	5.71%	5.69%	6.33%	6.30%
12/31/2027 (3)	5.75%	5.73%	6.36%	6.35%
12/31/2028 (3)	5.78%	5.77%	6.40%	6.38%
12/31/2029 (3)	5.80%	5.79%	6.43%	6.42%
2025-2027 Avg.	-	5.69%	-	6.30%
2025-2029 Avg.	-	5.72%	-	6.34%
Composite Rate		5.41%		6.04%

(1) Source: Mergent Bond Record, Volume 90, No.1 (January 2025), at 407-408.

(2) Source: Federal Reserve Bank of St. Louis, at <https://fred.stlouisfed.org/series/DBAA>

(3) Source: Corporate Bond Implied Forward Rates. Bloomberg Finance L.P. (Accessed January 14, 2025).

Risk Premium Method (RPM)
Historical Corporate Bond Yield Spread Differentials (January 2024 - December 2024)
Based on Moody's Long-Term Credit Ratings

Exhibit VVR-12

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Period	Corporate Bonds			Public Utility Bonds			Bond Yield Spread Differentials		
	"Aaa" Rated	"A" Rated	"Baa" Rated	"Aa" Rated	"A" Rated	"Baa" Rated	"Aa" (Pub. Util.) vs. "Aaa" Corp.	"A" (Pub. Util.) vs. "Aaa" Corp.	"Baa" (Pub. Util.) vs. "Aaa" Corp.
Jan-24	4.87%	5.31%	5.68%	5.34%	5.48%	5.73%	0.47%	0.61%	0.86%
Feb-24	5.03%	5.43%	5.77%	5.42%	5.56%	5.79%	0.39%	0.53%	0.76%
Mar-24	5.01%	5.42%	5.75%	5.43%	5.55%	5.79%	0.42%	0.54%	0.78%
Apr-24	5.28%	5.67%	6.00%	5.67%	5.79%	6.01%	0.39%	0.51%	0.73%
May-24	5.25%	5.62%	5.95%	5.62%	5.74%	5.97%	0.37%	0.49%	0.72%
Jun-24	5.13%	5.50%	5.82%	5.50%	5.61%	5.84%	0.37%	0.48%	0.71%
Jul-24	5.12%	5.52%	5.84%	5.54%	5.64%	5.85%	0.42%	0.52%	0.73%
Aug-24	4.87%	5.28%	5.60%	5.27%	5.38%	5.61%	0.40%	0.51%	0.74%
Sep-24	4.68%	5.10%	5.42%	5.09%	5.20%	5.41%	0.41%	0.52%	0.73%
Oct-24	4.95%	5.33%	5.63%	5.29%	5.41%	5.61%	0.34%	0.46%	0.66%
Nov-24	5.14%	5.49%	5.78%	5.43%	5.55%	5.75%	0.29%	0.41%	0.61%
Dec-24	5.20%	5.53%	5.80%	5.45%	5.58%	5.77%	0.25%	0.38%	0.57%
12-Month Average	5.04%	5.43%	5.75%	5.42%	5.54%	5.76%	0.38%	0.50%	0.72%

Source: Mergent Bond Record, January 2025, Volume 90, No. 1. Moody's Long-Term Corporate Bond Yield averages reference corporate and utility bonds with maturities as close as possible to 30 years.

Risk Premium Method (RPM)
Equity Risk Premium Using Total Market Approach
Gas LDC Group

Exhibit VVR-12

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Historical Equity Risk Premium

Annual Total Returns for S&P 500 Composite Index, Arithmetic Average (1926-2023) (1)	12.04%
Annual Total Returns for Long-Term Corporate Bonds, Arithmetic Average (1926-2023) (2)	6.15%
<u>Historical Equity Risk Premium - Total Market (3)</u>	<u>5.89%</u>

Prospective Equity Risk Premium

Prospective Annual Market Return (Next 3-5 years) (4)	11.48%
Prospective "Aaa" Rated Corporate Bond Yield (5)	5.41%
<u>Prospective Equity Risk Premium - Total Market (6)</u>	<u>6.07%</u>

<u>Indicated Equity Risk Premium - Total Market (7)</u>	<u>5.98%</u>

Beta Coefficient - Gas LDC Group (8)	0.91

<u>Equity Risk Premium (Gas LDC Group) (9)</u>	<u>5.44%</u>

(1) Source: Kroll Cost of Capital Navigator; arithmetic average of total returns for large company stocks (S&P 500 Index) (1926-2023).

(2) Source: Morningstar Indexes and SBBI Yearbook (2023, Kroll, LLC), arithmetic average of total returns for long-term high-grade corporate bonds (1926-2023).

(3) (1) - (2) above.

(4) From page 1 of Exhibit VVR-11

(5) From pages 1 and 2 of this Exhibit.

(6) (4) - (5) above.

(7) Average of (3) and (6) above.

(8) Average beta coefficient reported by Value Line for the Gas LDC Group.

(9) (7) x (8) above.

Risk Premium Method (RPM)
Equity Risk Premium - Public Utility Index Approach
Gas LDC Group and Combination Utility Group

Exhibit VVR-12

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Historical Equity Risk Premium - Public Utility Index Approach

Annual Holding Period Returns for S&P 500 Utilities Index, Arithmetic Average (1926-2024) (1)	10.75%
Annual Yield on Moody's "A" Rated Public Utility Bonds, Arithmetic Average (1926-2024) (2)	6.22%
Equity Risk Premium (Historical) - Public Utility Index Approach (3)	4.54%

Currently Implied Equity Risk Premium - Public Utility Index Approach

DCF Approach - S&P 500 Utilities Index	
Dividend Yield (4)	3.15%
Growth Rate (5)	7.47%
DCF Market Return - S&P Utilities Index (6)	10.63%
Recent 6-Month Average of Moody's "A" Rated Public Utility Bond Yields (7)	5.46%
Equity Risk Premium (Currently Implied) - S&P 500 Utilities (8)	5.17%
Indicated Equity Risk Premium - Public Utility Index Approach (9)	4.85%

(1) Source: S&P 500 Utilities Index historical data (currently comprised of 30 utility companies). See page 6 of this Exhibit.

(2) Source: Moody's Public Utility Manual and Mergent Bond Record. Historical yields on "A" rated utility bonds, representing the midpoint of Moody's reported utility credit ratings (Aa/A/Baa). See page 6 of this Exhibit.

(3) (1) - (2) above.

(4) Source: www.spindices.com. Recently reported dividend yield for S&P 500 Utilities Index companies (December 31, 2024), adjusted upward by one-half of the expected dividend growth rate as reflected in footnote (5).

(5) Source: Bloomberg Finance LP. Average long-term consensus earnings growth estimate for the S&P 500 Utilities Index.

(6) (4) + (5) above.

(7) See page 3 of this Exhibit.

(8) (6) - (7) above. Subject to rounding differences.

(9) Average of (3) and (8) above.

Year	S&P 500 Utilities Index	Moody's "A" Rated Utility Bond Yields	Moody's "Baa" Rated Utility Bond Yields
1926	5.38%	5.17%	5.67%
1927	28.99%	5.02%	5.46%
1928	56.94%	4.95%	5.33%
1929	11.98%	5.22%	5.76%
1930	-20.89%	5.06%	5.88%
1931	-34.45%	5.12%	6.90%
1932	-0.85%	6.46%	8.78%
1933	-20.30%	6.32%	9.38%
1934	-18.08%	5.55%	7.49%
1935	74.61%	4.61%	5.56%
1936	20.99%	4.08%	4.67%
1937	-35.64%	3.98%	5.09%
1938	21.92%	3.90%	5.26%
1939	11.71%	3.52%	4.50%
1940	-16.30%	3.24%	4.05%
1941	-30.50%	3.07%	3.84%
1942	14.25%	3.09%	3.73%
1943	47.07%	2.99%	3.58%
1944	18.23%	2.97%	3.52%
1945	53.66%	2.87%	3.39%
1946	2.66%	2.71%	3.03%
1947	-11.85%	2.78%	3.08%
1948	4.67%	3.02%	3.36%
1949	30.99%	2.90%	3.28%
1950	3.26%	2.79%	3.18%
1951	18.02%	3.11%	3.39%
1952	18.55%	3.24%	3.53%
1953	7.45%	3.49%	3.73%
1954	24.18%	3.16%	3.51%
1955	11.07%	3.22%	3.43%
1956	5.05%	3.56%	3.78%
1957	6.33%	4.24%	4.46%
1958	39.86%	4.20%	4.43%
1959	7.46%	4.78%	4.96%
1960	19.85%	4.78%	4.97%
1961	29.04%	4.62%	4.83%
1962	-2.61%	4.54%	4.75%
1963	12.26%	4.39%	4.67%
1964	15.69%	4.52%	4.74%
1965	4.67%	4.58%	4.78%
1966	-4.60%	5.39%	5.60%
1967	-0.59%	5.87%	6.15%
1968	5.45%	6.51%	6.87%
1969	-11.28%	7.54%	7.93%
1970	15.67%	8.69%	9.18%
1971	2.22%	8.16%	8.63%
1972	7.57%	7.72%	8.17%
1973	-17.59%	7.84%	8.17%
1974	-21.13%	9.50%	9.84%
1975	43.23%	10.09%	10.96%

Year	S&P 500 Utilities Index	Moody's "A" Rated Utility Bond Yields	Moody's "Baa" Rated Utility Bond Yields
1976	30.48%	9.29%	9.82%
1977	8.37%	8.61%	9.06%
1978	-3.53%	9.29%	9.62%
1979	13.27%	10.49%	10.96%
1980	14.27%	13.34%	13.95%
1981	11.19%	15.95%	16.60%
1982	24.90%	15.86%	16.45%
1983	19.47%	13.66%	14.20%
1984	24.47%	14.03%	14.53%
1985	31.64%	12.47%	12.96%
1986	28.08%	9.58%	10.00%
1987	-2.51%	10.10%	10.53%
1988	17.75%	10.49%	11.00%
1989	45.82%	9.77%	9.97%
1990	-2.83%	9.86%	10.06%
1991	13.98%	9.36%	9.55%
1992	7.64%	8.69%	8.86%
1993	14.38%	7.59%	7.91%
1994	-7.88%	8.31%	8.63%
1995	40.86%	7.89%	8.29%
1996	2.90%	7.75%	8.17%
1997	23.68%	7.60%	7.95%
1998	14.39%	7.04%	7.26%
1999	-8.67%	7.62%	7.88%
2000	58.55%	8.24%	8.36%
2001	-30.05%	7.76%	8.03%
2002	-29.99%	7.37%	8.02%
2003	26.26%	6.58%	6.84%
2004	24.28%	6.16%	6.40%
2005	16.84%	5.65%	5.92%
2006	20.99%	6.07%	6.32%
2007	19.38%	6.07%	6.33%
2008	-28.98%	6.52%	7.23%
2009	11.91%	6.05%	7.06%
2010	5.46%	5.45%	5.95%
2011	19.91%	5.04%	5.57%
2012	1.29%	4.13%	4.86%
2013	13.21%	4.48%	4.98%
2014	28.98%	4.28%	4.80%
2015	-4.85%	4.12%	5.03%
2016	16.29%	3.93%	4.68%
2017	12.11%	4.00%	4.38%
2018	4.11%	4.25%	4.67%
2019	26.35%	3.77%	4.19%
2020	0.48%	3.02%	3.39%
2021	17.67%	3.11%	3.36%
2022	1.57%	4.72%	5.03%
2023	-7.08%	5.54%	5.84%
2024	23.43%	5.54%	5.76%
Average	10.75%	6.22%	6.73%

Risk Premium Method (RPM)
Combination Utility Group - Indicated Cost of Equity

Exhibit VVR-12

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Prospective "Aaa" Rated Corporate Bond Yield (1)	5.41%
Yield/Credit Spread Adjustment Between "Aaa" Rated Corporate Bond Yields and "A" Rated Public Utility Bond Yields (2)	0.50%
<u>Prospective "A" Rated Public Utility Bond Yield (3)</u>	<u>5.91%</u>
Yield/Credit Spread Adjustment Between "A" Rated Public Utility Bonds and A-/Baa1 Rating of the Combination Utility Group (4)	0.11%
<u>Prospective Bond Yield for Combination Utility Group (5)</u>	<u>6.02%</u>
Equity Risk Premium	
- Total Market Index Approach (6)	5.50%
- Public Utility Index Approach (7)	4.85%
<u>Indicated Equity Risk Premium (8)</u>	<u>5.18%</u>
<u>Indicated Cost of Equity - Combination Utility Group (9)</u>	<u>11.20%</u>

- (1) See page 2 of this Exhibit. Average "Aaa" rated long-term corporate bond implied forward rate for the 2025-2029 period
- (2) See page 3 of this Exhibit. Yield adjustment derived from historical corporate bond yield data (recent 12 months) found in the Mergent Bond Record.
- (3) Sum of (1) and (2) above.
- (4) Adjustment to reflect bond yield/credit spread differential between "A" rated Public Utility Bonds and A- / Baa1 rating of the Combination Utility Group, as reflected on page 3 of this Exhibit. The 0.11% adjustment was derived via linear interpolation between the yield spread differential for "A" rated versus "A-"/"Baa1" rated Public Utility Bonds $((5.76\% - 5.54\%)/3 \times 1.5 = 0.11\%)$.
- (5) (3) + (4) above. May reflect rounding differences.
- (6) See page 8 of this Exhibit.
- (7) See page 5 of this Exhibit.
- (8) Average of (6) and (7) above.
- (9) Sum of (5) and (8) above.

Risk Premium Method (RPM)
Equity Risk Premium Using Total Market Approach
Combination Utility Group

Exhibit VVR-12

Page 8 of 10

Historical Equity Risk Premium

Annual Total Returns for S&P 500 Index, Arithmetic Average (1926-2023) (1)	12.04%
Annual Total Returns for Long-Term Corporate Bonds, Arithmetic Average (1926-2023) (2)	6.15%
Historical Equity Risk Premium - Total Market (3)	5.89%

Prospective Equity Risk Premium

Prospective Annual Market Return (Next 3-5 years) (4)	11.48%
Prospective Aaa Rated Corporate Bond Yield (5)	5.41%
Prospective Equity Risk Premium - Total Market (6)	6.07%
Indicated Equity Risk Premium - Total Market (7)	5.98%
Beta Coefficient - Combination Utility Group (8)	0.92
Equity Risk Premium (Combination Utility Group Beta) (9)	5.50%

(1) Source: Kroll Cost of Capital Navigator; arithmetic average of total returns for large company stocks (S&P 500 Index) (1926-2023).

(2) Source: Morningstar Indexes and SBBI Yearbook (2023, Kroll, LLC), arithmetic average of total returns for long-term high-grade corporate bonds (1926-2023).

(3) (1) - (2) above.

(4) From page 1 of Exhibit VVR-11.

(5) From pages 1 and 2 of this Exhibit.

(6) (4) - (5) above.

(7) Average of (3) and (6) above.

(8) Average beta coefficient reported by Value Line for the Combination Utility Group.

(9) (7) x (8) above.

Risk Premium Method (RPM)
Non-Regulated Group - Indicated Cost of Equity

Prospective "Aaa" Rated Corporate Bond Yield (1)	5.41%
Yield/Credit Spread Adjustment Between Aaa Rated Corporate Bond Yield and Average A-/A3 Rated Corp. Bond Yield of Non-Regulated Group (2)	0.50%
<u>Prospective Bond Yield for Non-Regulated Group (3)</u>	<u>5.91%</u>
Equity Risk Premium	
- Total Market Index Approach (4)	5.44%
<u>Indicated Equity Risk Premium</u>	<u>5.44%</u>
<u>Indicated Cost of Equity - Non-Regulated Group (5)</u>	<u>11.35%</u>

- (1) See page 2 of this Exhibit. Average "Aaa" rated long-term corporate bond implied forward rate for the 2025-2029 period
- (2) See page 3 of this Exhibit. Yield adjustment derived from historical corporate bond yield data (recent 12 months) reported in the Mergent Bond Record (January 2025). Yield differential between Aaa corporate bonds and A- / A3 rated corporate bonds.
- (3) (1) + (2) above.
- (4) See page 10 of this Exhibit.
- (5) Sum of (3) and (4) above.

Risk Premium Method (RPM)
Equity Risk Premium Using Total Market Approach
Non-Regulated Group

Exhibit VVR-12

Page 10 of 10

Historical Equity Risk Premium

Annual Total Returns for S&P 500 Index, Arithmetic Average (1926-2023) (1)	12.04%
Annual Total Returns for Long-Term Corporate Bonds, Arithmetic Average (1926-2023) (2)	6.15%
Historical Equity Risk Premium - Total Market (3)	5.89%

Prospective Equity Risk Premium

Prospective Annual Market Return (Next 3-5 years) (4)	11.48%
Prospective Aaa Rated Corporate Bond Yield (5)	5.41%
Prospective Equity Risk Premium - Total Market (6)	6.07%

Indicated Equity Risk Premium - Total Market (7)	5.98%

Beta Coefficient - Non-Regulated Group (8)	0.91

Equity Risk Premium (Non-Regulated Group) (9)	5.44%

(1) Source: Kroll Cost of Capital Navigator; arithmetic average of total returns for large company stocks (S&P 500 Index) (1926-2023).

(2) Source: Morningstar Indexes and SBBI Yearbook (2023, Kroll, LLC), arithmetic average of total returns for long-term high-grade corporate bonds (1926-2023).

(3) (1) - (2) above.

(4) From page 1 of Exhibit VVR-11.

(5) From pages 1 and 2 of this Exhibit.

(6) (4) - (5) above.

(7) Average of (3) and (6) above.

(8) Average beta coefficient reported by Value Line for the Non-Regulated Group.

(9) (7) x (8) above.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

V.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2025-3053499

DIRECT TESTIMONY OF
NICOLE M. PALONEY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

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I. Introduction

Q. Please state your name and business address.

A. My name is Nicole Paloney, and my business address is 121 Champion Way, Suite 100, Canonsburg, Pennsylvania 15317.

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

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as Director of Rates and Regulatory Affairs.

Q. What are your responsibilities as Director of Rates and Regulatory Affairs?

A. I am responsible for developing and directing rate activity on behalf of the Company before the Pennsylvania Public Utility Commission ("Commission") as well as coordinating and representing the Company's position in a variety of regulatory matters and proceedings.

Q. What is your educational and professional background?

A. I have a Bachelor of Science in Business and Administration with an emphasis in Accounting and Finance from The Ohio State University. In 1998, I was hired as a staff auditor for Deloitte, primarily serving middle market clients in a variety of industries, including manufacturing, public pension systems and not for profit clients. I was promoted to manager in 2004 and served in that capacity until I left Deloitte in July 2005. From August 2005 until August 2008, I was employed by Cardinal Health in Dublin, Ohio. Cardinal Health provides pharmaceutical and

1 medical products to the Health Care industry and is also a manufacturer of medical
2 and surgical products. I was a manager in Internal Audit during my tenure at
3 Cardinal, with responsibility over internal audits that took place in the
4 manufacturing and corporate segments of the company.

5 In August 2008, I joined NiSource Corporate Services Company (“NCSC”) as
6 an Internal Audit manager, with responsibility for internal audits that took place in
7 NiSource Inc.’s (“NiSource”) Gas Distribution segment. In September 2011, I
8 transitioned to the Regulatory Strategy and Support group in the role of Project
9 Manager, providing support to the state regulatory teams in Pennsylvania and
10 Maryland. In May 2014, I began my role as Director of Rates and Regulatory Affairs
11 for the Company.

12 **Q. Have you previously testified before this Commission or any other**
13 **regulatory agency?**

14 A. Yes. I have testified before the Pennsylvania Public Utility Commission
15 (“Commission”) on behalf of Columbia in its 2015, 2016, 2018, 2021, 2022, and 2024
16 base rate cases at Docket Nos. R-2015-2468056, R-2016-2529660, R-2018-2647577,
17 R-2021-3024296 R-2022-3031211, and R-2024-3046519, respectively. In addition
18 to base rate proceedings in Pennsylvania, I also have submitted testimony in support
19 of Columbia’s request to increase the cap on its Distribution System Improvement
20 Charge (Docket No. P-2015-2521993) and in an abandonment proceeding (Docket
21 No. A-2015-2513395), as well is in the Company’s Purchased Gas Cost proceedings

1 at Docket Nos. R-2020-3018993, R-2021-3024349, R-2022-3031172, R-2023-
2 3038630, and R-2024-3047014. I also have testified before the Public Service
3 Commission of Maryland in Columbia Gas of Maryland, Inc. base rate cases as a cost-
4 of-service witness in Case No. 9316 and as a policy witness in Case Nos. 9354, 9480,
5 9664, 9680, and 9754.

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

7 A. I will address the Company's performance during 2024 and at the outset of 2025, and
8 address Columbia's performance quality in compliance with Section 523 of the Public
9 Utility Code. Further, I will address the Company's proposal to add Economic
10 Development Distribution Service ("EDDS") to its Tariff.

11 **II. Management Effectiveness**

12
13 **Q. Is the Company seeking a rate of return adjustment for management**
14 **effectiveness in this proceeding?**

15 A. Yes. The Company, and its employees, continue to perform at a high level to the
16 benefit of our customers and the communities we serve. Based upon the Company's
17 management effectiveness, its rate of return witness Vincent Rea has included a 25-
18 basis point adjustment in his recommended rate of return on common equity in this
19 case.

20 **Q. What topics will you be addressing regarding the Company's**
21 **performance?**

22 A. I will address a number of topics individually, as follows:

- Columbia's Commitment to Low-Income Customers;
- Performance results from the Utility Consumer Activities Report and Evaluation ("UCARE") and Quality of Service Reports;
- Process Improvements Enhancing Customer Service;
- Improvements made for Customer, Employee and System Safety;
- Serving Our Communities; and
- Management Audit Performance.

A. Commitment to Low-Income Customers

Q. How does Columbia meet the unique needs of its low-income customer base?

A. Columbia is committed to delivering the highest level of customer service to its low-income customers using an all-inclusive approach, starting from the initial contact with an identified low-income customer. Customers are screened and appropriately referred to one of Columbia's many assistance programs. The following programs are mandated Universal Service Programs in place since the passage of Pennsylvania's Natural Gas Choice and Competition Act of 1999:

- **Customer Assistance Program ("CAP"):** CAP provides income-qualified customers with a reduced asked-to-pay amount on their bills. In 2024, 28,770 Columbia customers received CAP assistance.

- 1 • **Low-Income Usage Reduction Program (“LIURP”):** In LIURP third-
2 party vendors are retained to insulate homes and install high-efficiency
3 furnaces for eligible low-income customers. As I discuss later in my testimony,
4 Columbia’s LIURP program consistently realizes above industry-average
5 savings and is the second largest program among the state’s gas utilities. In
6 2024, the Company completed 321 jobs and spent \$5.5 million dollars of its
7 \$6,015,659 budget.
- 8 • **Emergency Repair Program (“ERP”):** Columbia’s ERP is currently
9 funded at \$1,000,000 annually. The ERP assists homeowners with incomes
10 less than 200% of the Federal Poverty Income Guidelines (“FPIG”) have unsafe
11 or faulty heating equipment, gas lines or hot water tanks repaired or replaced
12 by a participating contractor. In 2024, the Company served 282 customers and
13 disbursed its entire \$1,000,000 budget.
- 14 • **Hardship Funds:** The Company matches customer donations dollar-for-
15 dollar with shareholder contributions in its hardship fund, which provides
16 grants to help payment troubled customers with their gas bills. In 2024, 1,513
17 customers received \$550,067 through this fund.

1 • **Customer Assistance Referral and Evaluation Services (“CARES”):**

2 CARES provides a case management approach to help customers with special
3 needs and short-term payment troubles. The Company’s bilingual CARES
4 representative is available to all vulnerable customers who are experiencing a
5 crisis and require personalized support.

6 In addition, the Company provides a voluntary energy efficiency program,
7 WarmWise: Audits and Rebates (“A&R”), for customers with incomes up to 250%
8 FPIG who do not qualify for LIURP. Columbia’s A&R provides a free Building
9 Performance Institute certified audit and up to \$3,600 in recommended energy
10 efficiency measures. In 2024, the Company provided 171 customers more than
11 \$700,000 in energy efficiency measures.

12 To gain direct access to our programs, the Company utilizes a best practice of
13 maintaining a toll-free energy assistance hotline, allowing agencies¹ to directly
14 contact our skilled Energy Assistance Team (“EAT”) to coordinate grant approvals
15 and assist with identifying all programs best suited to the needs of their clients. The
16 EAT manages all facets of the LIHEAP and hardship fund programs, from outreach
17 to processing grants and refunds. This single point of contact provides Columbia
18 direct, on-going contact with agency representatives allowing staff to build
19 relationships to serve customers with the best possible outcomes.

¹ Agencies are Community Based Organizations that assist customers in applying for assistance. I discuss these agencies in more detail later in my testimony.

1 Further, the Company regularly reviews its policies, procedures, and outreach
2 efforts to strive for the optimal balance between maximizing benefits and minimizing
3 costs. The Company also considers any new needs or emerging trends requiring
4 changes to programs and procedures. In 2024, the Company attended more
5 grassroots events than ever before (197 events), entered into an agreement to utilize
6 newly available data from the Department of Human Services (“DHS”) and
7 implemented many changes to its Universal Service Programs that were approved by
8 the Commission as part of its Universal Service and Energy Conservation Plan
9 (“USECP”).

10 **Q. In addition to the required Universal Service Programs listed above,**
11 **what other assistance programs are available to Columbia’s customers?**

12 A. The following programs are available to Columbia’s customers and access to them is
13 encouraged by the Company’s EAT:

14 • **Low-Income Home Energy Assistance Program (“LIHEAP”):**

15 LIHEAP assists low-income families pay heating bills in the form of a cash
16 grant to approved vendors. Columbia is an approved vendor. The Company’s
17 EAT encourages low-income customers to apply for LIHEAP and can assist in
18 completing the application. In the 2023/2024 program year, 15,561 customers
19 received \$5,830,855 in assistance.

- **CRISIS:** The CRISIS Program is a component of LIHEAP that provides grants for customers that are without heat or are facing a heating emergency due to a threat of disconnection or faulty heating equipment. The Company's EAT provides customers with information about the program and can assist in completing the application. In the 2023/2024 program year, 2,630 customers received \$1,112,887 in grants.

Q. How do Columbia's programs demonstrate excellence?

A. Columbia's Universal Services team operates using a continuous improvement framework. This model allows for the quick and efficient implementation of approved pilot programs, various outreach initiatives, such as email campaigns aimed at securing CRISIS grant approvals through the DHS direct referral program, and targeted outreach to customers requiring assistance through various programs for re-entry into CAP. Here are additional examples of how Columbia's Universal Service Programs demonstrate excellence:

- **CARES:** The extensive experience of Columbia's CARES team provides it with the ability to navigate the ever-changing needs of the low-income community with a thoughtful, customer focused approach. The team is trained to assist and complete CAP, LIHEAP and hardship fund applications for our most vulnerable customers. The Company recognized the importance of serving non-English-speaking customers and therefore, hired a Spanish speaking CARES representative, Spanish speaking CAP

1 Intake representatives, and Spanish speaking customer service
2 representatives, as well as obtained access to a multilingual interpreter
3 service. Additional examples of service provided by Columbia's CARES
4 team include, but are not limited to:

- 5 o Victims of domestic violence each get a dedicated CARES representative
6 who is trained to handle such cases with confidentiality and compassion.
- 7 o Based on feedback from community advocates, grass roots outreach was
8 expanded. Columbia was one of the first utilities to assign a dedicated
9 full time staff member specifically to conduct community outreach.
10 Since bringing on the full-time staff member to conduct community
11 outreach in mid-2021, Columbia has attended over 672 events in the
12 community.

- 13 • **LIURP:** The Company has implemented several changes to remove barriers
14 for participation in the LIURP program and has implemented measures that
15 have resulted in savings to both low-income and non-low-income customers.
16 Examples are as follows:

- 17 o **Employing a full time Quality Assurance Coordinator:** As the
18 LIURP program is managed internally, the Company recognized the
19 need for a full time Quality Assurance Coordinator to handle day-to-day
20 troubleshooting and oversee the post-inspection program component.
21 This position is essential to the Company's successful reductions in gas

usage, which have averaged 20% or higher per job completed since 2017. In the last five reporting years, the highest gas industry average was 16.6% as reported in the Universal Service Programs and Collections Performance Report.

o **Application of Individualized Weatherization Measures:**

Columbia is the only company in Pennsylvania to use an individualized measure of projected savings to guide auditors and crews on the maximum spend for each home, as opposed to setting the level of spend based on the square footage of the home. Prior gas costs are also considered as part of the spend level on each home. The methodology provides a guideline for how much can be spent to meet the seven-to-twelve-year payback based on gas costs and historical savings. This approach provides an opportunity to treat each home to achieve the best savings and not rely on a “one size fits all” model.

o **Reducing Deferrals:** A deferral occurs when a condition exists in the home that prevents the Company from weatherizing the home. Columbia recognized the associated costs with deferrals, as well the need to reduce deferrals while increasing the number of homes weatherized and voluntarily procured a study of the impact of these situations. The study resulted in the design of Columbia’s Health and Safety Pilot (“H&S Pilot”) that aims to address barriers to weatherization, ensuring that

homes can be safely weatherized. Homes that were previously deferred multiple times due to roof leaks, knob and tube wiring and other obstacles are now being weatherized, resulting in some of the highest energy savings achieved by Columbia’s customers. Of the 18 homes completed with H&S Pilot funds in 2022, Cubic Feet per Minute (“CFM”) reductions ranged from 12.44% to 76.42%. The following chart provides the number of homes completed and total dollars spent through the H&S Pilot.

	2022	2023	2024
# Completions	18	33	65
Total Cost	\$93,000.00	\$125,603.34	\$179,153.00
Average Cost	\$ 5,166.67	\$ 3,925.10	\$2,756.20

This Pilot exclusively serves CAP customers, thereby reducing CAP shortfall costs recovered from non-CAP residential customers.

- o **Rental Property LIURP Participation:** In 2024, the Company focused on increasing LIURP participation for customers who reside in rental properties. A prescreening metric was added to increase the number of daily weatherization requests sent to landlords, resulting in 224 introductory letters sent to landlords. In 2024, rental units comprised 8.4% of total weatherization completions, and the Company expects that amount this will increase in 2025. In addition, the

1 Company collaborated with its Universal Service Advisory Council
2 (“USAC”) to improve the wording in the LIURP solicitation letters.
3 Finally, the Company improved its communication with landlords by
4 adding a LIURP follow up letter that explains the outcome of the audit,
5 outlines the recommended measures to be installed, and provides the
6 landlord an opportunity to review and discuss before the work begins.
7 Once a landlord completes the process and has a positive experience, the
8 Company reaches out to assess all other properties owned by that
9 landlord to determine if any additional tenants and properties meet the
10 eligibility guidelines.

- 11 • **CAP** - The current CAP program offers four- and six- percent of income
12 payment options, as well as a percent of budget option. The Company’s CAP
13 does not have a maximum CAP credit, (difference between the tariff bill and
14 the amount of the CAP payment plan), and opts to encourage energy
15 efficiency measures for these customers rather than raise the required
16 payment to an unaffordable level. The Commission’s 2023 Universal
17 Service Programs and Collections Performance Report lists the Company as
18 having the highest CAP credit per CAP customer of all gas utilities, thereby
19 providing the most benefit for its CAP customers. Finally, the Company
20 forgives arrears over three years and does not limit the forgiveness to one
21 time.

- **Leveraging Funding:** The Company redoubled its efforts to leverage funding from all available sources to maximize dollars and benefits to customers. In 2024, 37 A&R-eligible customers received benefits from the ERP to cover the cost of their heating system and water tank replacements in addition to energy efficiency benefits. Forty-six customers referred to ERP were served through LIURP, addressing their emergency needs while also providing energy efficiency measures. With encouragement from the Company, several A&R contractors referred their electric program and county weatherization program customers, who did not qualify for LIURP, to A&R, allowing them access an additional \$3,600 in measures. Through these efforts, 57 customers received additional energy efficiency measures, totaling \$222,300, that would not have been installed without the A&R funds.

Further, customers participating in the A&R program were provided information on rebates offered to all residential customers if they were purchasing eligible equipment to ensure the maximum benefit allowable was received. In addition, all customers that participated in the online energy audit or applied for a rebate and self-declared their income were referred to either the A&R program or the LIURP program based on eligibility. In January 2025, a virtual meeting was held with all participating

1 A&R contractors to explain the newest available rebate beginning in 2025²,
2 insulation and air sealing. Processes were developed for a seamless
3 application, so a customer could obtain benefits from both programs to
4 provide more insulation and air sealing at no cost to the customer.

5 Finally, in the Fall of 2024 Columbia entered into an agreement with DHS to use data
6 shared by the DHS for the purposes of streamlining enrollment into CAP and re-
7 verifying customers' income when in CAP.

8 **Q. How does Columbia communicate available assistance to its low-income**
9 **customers?**

10 A. The Company sponsors a paid social media campaign every year in the fall and
11 January/February to promote LIHEAP and CRISIS. In addition, social media,
12 including X, Next Door and Facebook, are utilized year-round to remind customers
13 of all available assistance programs. Multiple press releases are issued throughout
14 the year and in recent years, Columbia's President has issued an opinion and editorial
15 release on the importance of seeking assistance when in need. Columbia sponsors
16 multiple events in support of the Dollar Energy Fund ("DEF") to increase awareness
17 and donations. Bill inserts are included in the fall and February to promote LIHEAP
18 and CRISIS. During the winter months, the Company conducts email campaigns to
19 promote programs that target eligible customers. In February and March,
20 individualized emails are used to notify and assist customers who received LIHEAP

² This measure was approved in Company's 2024 base rate case at Docket R-2024-3046519.

1 and are in threat of termination with applying for CRISIS through the DHS Utility
2 File Transfer process. The Utility File Transfer process allows the Company to
3 request permission from a customer who has already received a LIHEAP grant and
4 is still in threat of termination to apply for CRISIS on the customer's behalf. As
5 already mentioned, the Company also invests significant time in grassroots outreach
6 in individual communities.

7 **Q. What additional outreach measures were identified and implemented in**
8 **2024?**

9 A. The Company created a CAP flyer to promote the benefits of the program and
10 included it in the annual cold weather survey packet that is left at customers' homes.
11 The target audience of our yearly and already extensive grassroots outreach
12 expanded to include colleges, laundromats, and community celebrations. In 2024,
13 the Company attended or provided materials to 197 community events across its
14 service territory. In addition, Columbia completed a revised video for community-
15 based organizations ("CBOs") to explain the basics of CAP, which allows
16 representatives to refresh their understanding at any time to enroll customers into
17 CAP. The Company and its administrator, DEF, also reviewed the current list of CBOs
18 and have targeted specific areas to solicit additional organizations to meet the
19 demand and limit customer travel.

20 **Q. How does Columbia use CBO to assist the low-income population?**

21 A. Columbia contracts with DEF to administer its hardship fund and CAP. DEF

1 contracts with local CBOs to complete applications at their local offices. Columbia
2 regularly updates these agencies through DEF with any new guidelines or changes.
3 Columbia also contracts with Rebuilding Together Pittsburgh (“RTP”) to administer
4 its ERP and A&R. RTP regularly cross references customers to all available assistance
5 programs when possible.

6 Additionally, the Company convenes its USAC, which consists of low-income
7 advocates, twice a year to seek feedback and suggestions on current practices and
8 programs. In addition to providing detailed statistics and process reviews to the
9 USAC, the Company also seeks input on its budget program, CAP agreement form,
10 LIURP letters, collections practices, promotional materials, and outreach strategy,
11 among other emerging issues.

12 **Q. What improvements did Columbia make to drive efficiencies related to**
13 **Universal Service Program delivery?**

14 A. Columbia is very focused on affordability of its services and recognizes that the cost
15 of these programs is passed on to non-CAP residential customers. The Company
16 strives to keep administrative costs low to provide higher benefit levels to customers.
17 The Company experienced exponential increases in labor hours since 2020 due to
18 increased grassroots outreach, federal performance measure reporting
19 requirements, increased refunds due to higher LIHEAP grants with lower CAP
20 payment plans and additional assistance programs such as the Housing Assistance
21 Program and Emergency Rental Assistance Program. In addition, advocates have

1 encouraged targeted outreach to smaller, segmented groups of low-income
2 customers, which is labor intensive. The Company has met all the demands and
3 deadlines without increasing internal staff. Instead, the Company has relied on
4 improved automation, rebalancing of duties to meet peak call times and cross
5 training of all Universal Service personnel.

6 Specifically, internal staff have been trained to electronically query and update
7 databases to identify accounts that fall into various categories for unique
8 communications. With this effort, we can identify customers that need LIHEAP,
9 CRISIS and hardship funds. This also allows for the team to identify a combination
10 of the three programs and tailor a message to each customer on how to apply to
11 programs for which they are eligible. These same tools have assisted with eliminating
12 some of the manual review required for the end of the season LIHEAP refunds to the
13 state and reporting of performance measures. In addition, leveraging corporate
14 mailing and emailing functions have increased the communication channels more
15 efficiently and effectively.

16 Columbia also offers access to CAP, hardship funds, LIURP, and A&R programs
17 through its online applications and forms. Many customers appreciate the
18 convenience of applying online when they are available, rather than being limited to
19 traditional work hours. Although this method is highly beneficial for customers
20 applying for CAP, the program has faced challenges in keeping pace with the
21 additional administrative burdens related to unrecognizable or missing income

documentation. In addition, the implementation of the online CAP application was a significant IT investment, which included developing a secure communication transfer system between the Company and DEF.

Q. How have these measures impacted the costs to operate the Universal Service Programs?

A. Per the Commission's 2023 Universal Service Programs and Collections Performance report, Columbia's costs are the second lowest cost per active CAP customer in Pennsylvania.

Q. What is the Company proposing in the current case to assist low-income customers?

A. In Columbia Statement No. 16, Company witness Deborah Davis discusses the following programs:

- **CAP Pilot:** The Company proposes a two-year pilot program, wherein a one-time grant will be provided to a removed CAP customer to pay CAP arrears and re-enter the program. The Company recognizes arrears as a barrier for some customers to re-enter CAP and proposes the CAP Pilot to gauge whether eliminating this barrier will motivate customers to re-enter and remain successfully in the program.

- **Recovery of CARES and CAP Administration Costs Through Rider USP:** The Company is proposing to modify the recovery of costs associated with CARES, specifically LIHEAP, and CAP internal

administration. They are currently recovered through base rates as part of Operation & Maintenance expenses. These costs are directly related to all of Columbia's low-income assistance programs, and accordingly, these costs should be moved out of base rates and recovered through Rider USP.

- **Speech Analytics Pilot:** Per the Settlement of Columbia's base rate case at Docket R-2024-3046519, the Company is proposing a two-year pilot to use speech analytics technology to improve customer service representatives' awareness and identification of eligible CAP customers.

B. Performance Results: Utility Consumer Activities Report and Evaluation ("UCARE") and Quality of Service Reports

Q. What is the UCARE?

A. The UCARE is prepared annually by the Commission's Bureau of Consumer Services ("BCS"). The report details utility compliance with statutes and regulations concerning residential customer service and billing matters. The UCARE presents data on customer service performance for jurisdictional utilities in the electric, gas, water and telecommunications industries. The update provides a snapshot of overall BCS activity including the volume of Consumer Complaints, Payment Arrangement Requests ("PARs") and Inquiries. The report contains current information that can be reviewed by utility management, consumers, Commission staff and other interested parties. In January of 2025, the Commission issued its UCARE for 2023. The overall information contained in the Activities report illustrates the most recent information available on how well utilities handle consumer complaints.

Q. What were the results of the 2023 UCARE report?

A. As shown in Figure 1, below, Columbia's 2023 performance, as reflected in the UCARE report with regards to the five major natural gas companies, is among the best in most categories across the Pennsylvania gas utility industry. In the measure of Residential Consumer Complaints, Columbia had the second to lowest consumer complaint rate of 0.49 per 1,000 residential customers in Pennsylvania. Columbia's consumer complaint rate was also better than the average complaint rate of 0.94 of the five major natural gas companies. It further shows that Columbia had one of the lowest Justified Consumer Complaints at a rate of 0.02 justified consumer complaints, far lower than the 0.11 average justified consumer complaint rate for all of Pennsylvania's gas utilities. Finally, Figure 1 shows that Columbia has the lowest percentage of justified consumer complaints at 3.4% compared to the industry high of 17%. I attribute this result to the hard work of our dedicated field employees for doing the right thing and treating our customers fairly and with the respect they deserve.

Figure 1

**2023 Residential Consumer Complaint Rates,
Justified Consumer Complaint Rates, and Percent of Justified Consumer Complaints
Major Natural Gas Distribution Companies**

Utility	Consumer Complaint Rate	Justified Consumer Complaint Rate	Percent of Justified Consumer Complaints
Columbia	0.49	0.02	3.4%
NFG	0.42	0.06	13.3%
Peoples	0.58	0.02	3.8%
PGW	2.32	0.39	17.0%
UGI Gas	0.87	0.07	8.3%
Industry Average	0.94	0.11	11.6%

Per Figure 2 below, Columbia's Justified Consumer Complaint Rate per 1,000 residential customers was 0.02 in 2021 and 2023 and was 0 in 2022. In addition, Columbia's Justified Consumer Complaint Rate is better than the natural gas utility average rate of 0.09, 0.12 and 0.11 from 2021-2023. I am especially proud of these numbers considering the substantial disruption that our pipeline replacement activities can have on customers and their communities. Nobody likes to have their streets, sidewalks and lawns dug up; however, our team provides quality work and respectful interactions with customers, and this is reflected in the low complaint rate. As a result, our customers are satisfied throughout the duration of our projects, despite causing them and their communities disruption from our construction activities.

Figure 2

**2021-23 Justified Residential Consumer Complaint Numbers/Rates
Major Natural Gas Distribution Companies**

Utility	2021		2022		2023	
	Number	Rate	Number	Rate	Number	Rate
Columbia	7	0.02	1	0.00	7	0.02
NFG	5	0.03	8	0.04	11	0.06
Peoples	12	0.02	13	0.02	13	0.02
PGW	150	0.31	227	0.47	190	0.39
UGI Gas	40	0.07	42	0.07	45	0.07
Total	214		291		266	
Industry Average		0.09		0.12		0.11

In the measure of Commission Infractions, Columbia had an infraction rate per 1,000

residential customers that was the lowest of all the utilities in 2021, 2022 and 2023. Figure 3, below, is illustrative.

Figure 3

**Commission Infraction Rates
Major Natural Gas Distribution Companies**

Utility	2021	2022	2023
Columbia	0.03	0.02	0.04
NFG	0.16	0.11	0.13
Peoples	0.06	0.02	0.06
PGW	0.47	0.83	0.83
UGI Gas	0.13	0.18	0.33

As shown in Figure 4 below, Columbia's Payment Arrangement Request ("PAR") rate was 1.47 in 2022 (most up to date per report) and the Justified PAR rate was 0.06. The percent of justified PARs was 4.3%, which is lower than the industry average of 4.87%, as shown in Figure 4 below.

Figure 4

**2022 Residential Payment Arrangement Request (PAR) Rates,
Justified PAR Rates, and Percent of Justified PARs
Major Natural Gas Distribution Companies**

Utility	PAR Rate	Justified PAR Rate	Percent of Justified PARs
Columbia	1.47	0.06	4.3%
NFG	2.23	0.12	5.5%
Peoples	1.93	0.06	3.2%
PGW	11.65	0.61	5.2%
UGI Gas	7.05	0.13	1.9%
Industry Average	4.87	0.20	3.8%

1
2 **Q. Can you provide an overview of Columbia's 2024 Quality of Service**
3 **Performance Report?**

4 A. Yes, Columbia's "Quality of Service Performance Report," which was filed on January
5 31, 2025, has five general categories: Call Center Performance, Residential and Small
6 Commercial Billing, Meter Reading, Dispute Reporting, and Customer Satisfaction.
7 Columbia's performance for each of these categories is explained below.

8 **1. Call Center Performance**

9 Columbia reports three separate measures of telephone access: 1) average
10 busy out rate; 2) call abandonment rate, and 3) percent of calls answered within 30
11 seconds.

12 Columbia's call volume for 2024 was 407,206, a 11% decrease from the
13 455,273 calls taken in 2023. Calls answered within 30 seconds improved to 82.65%
14 in 2024, reflecting an increase of 11.7% from 72.93% in 2023. The overall
15 abandonment rate improved to 2.25%, a reduction of 60% from 5.65% in 2023. The
16 Busy-Out Rate remains at 0%, which is consistent with Columbia's performance year
17 over year. Columbia remains focused on maintaining service levels of 80% for calls
18 answered within 30-seconds, increased customer service representative retention,
19 employee engagement and development. The team developed and implemented the
20 following actions in 2024 to improve customer satisfaction, call center performance,

1 and employee engagement:

- 2 • Maintain new-hire employee engagement program aims to retain Customer
3 Service Representative (“CSR”) through regular and scheduled touchpoints
4 from leadership, providing support, guidance, and motivation throughout
5 training.
- 6 • Developed additional computer-based training focused on customer
7 experience, customer satisfaction, CSR metrics, and service level
8 performance. This contributed to greater alignment with our CSR's
9 understanding of Key Performance Indicators and how meeting our goals
10 directly impacts performance.
- 11 • Prioritize annual refresher training sessions throughout the year. This
12 ensures our CSRs' skills and knowledge stay current and that processes and
13 procedures are consistently followed.
- 14 • Enhance and develop the Real-Time Analyst team to monitor real-time
15 performance and analyze interval call volumes, CSR availability, service
16 level adherence, and average speed of answer metrics, maximizing
17 effectiveness, efficiencies, and customer expectations. This robust model
18 has contributed to improvements in our service level metric.
- 19 • Utilize our CSR advancement program, which allows CSRs to develop
20 within their roles to reach advanced levels. This program will enable them

1 to increase their knowledge, gain more experience, enhance effectiveness,
2 and promote continuous improvement.

- 3 • Enhance employee engagement through discussion Customer Care Center's
4 (“CCC”) goals, objectives, successes, and opportunities. Our CCC leadership
5 team participated in leadership assessments and training sessions to
6 promote leadership development.

7 In 2024, Columbia completed several website enhancements, which included
8 new self-service pages to promote our wide range of self-service offerings, changes
9 to improve the user experience for customers enrolling in payment plans and more.

10 In 2024, the Company focused on enhancing our already compliant Americans
11 with Disability Act (“ADA”) websites to ensure that disabled customers have a
12 more accessible, easy-to-use website by implementing various enhancements such
13 as making documents easier to find, sharper color contrasts to make text easier to
14 read, simplifying navigation styles, updating link labels for screen readers, and
15 training our employees to make customer-facing PDF documents more accessible.
16 The Company has processed 352,000 start, stop and move orders online for
17 customers from April 14, 2021 through December 31, 2024.

18 In 2022, Columbia implemented an automated Chatbot and live chat
19 capability for its customers. The Chatbot is available 24 hours, 7 days a week, and
20 offers another option for customers to interact with the Company online. Customers
21 can also use the Chatbot to quickly learn their account balance, payment status, look

up an account number, retrieve a copy of their current bill or get help with a forgotten password. The Chatbot can also act as a guide for customers, who can either select a button (like Billing, Payments, or Outage & Emergency) or type in a specific request to receive a link that brings them to the information they are seeking. Columbia Gas of Pennsylvania customers completed 37,102 chat sessions in 2024.

In addition, in 2024, CSRs handled 768 live chats. When open, live chat is available Tuesday through Friday (4 hours per day). Columbia will continue to explore increasing the hours for live chat with CSRs based on overall business and staffing needs.

Columbia has 42 primary CSRs and 63 secondary CSRs³. Of those CSRs, 33 primarily support the Universal Service program, 26 provide secondary support for Universal services, and 2 CSRs are bilingual. In 2025 and beyond, Columbia's Customer Care Center's focus will be achieving a combined 80% service level for calls answered in 30 seconds, increasing retention and talent development for all employees.

2. Residential and Small Commercial Billing Data

For the thirteenth consecutive year, in 2024 Columbia did not have any deferred billings for its residential or small commercial customers. A strong emphasis on reducing occurrences of deferred bills by Columbia's Billing Exceptions Group

³ Primary CSRs are skilled to receive any Pennsylvania customer service type call starting at a zero-wait time in queue. The secondary CSRs are skilled to automatically support Pennsylvania customer service type calls if the wait time builds to a set threshold.

1 continues to aid in this success, and this group continues to exhibit a strong effort on
2 the prompt follow up of billing abnormalities.

3 Columbia printed and mailed approximately 3.2 million bills to customers in
4 2024. In addition, the Company issued approximately 2 million paperless bills.
5 Approximately 3.7 million electronic payments were posted to customer accounts,
6 accounting for 77.66% of total payments being posted electronically on accounts.

7 **3. Meter Reading**

8 In 2024, Columbia read over 5.4 million meters, with 99.90% of meters read
9 on the scheduled meter reading date. Columbia experienced a decrease in the average
10 number of meters not read monthly. In 2024, an average of 6 meters were not read
11 monthly, an improvement when compared to the average of 10 meters not read
12 monthly in 2023. These numbers are more reflective of the company's pre-COVID
13 meter reading stats since customer are providing more access to their homes for
14 inside basement meters. Also, the number of inside meters has decreased since 2021
15 due to the Company's ongoing initiatives to relocate the inside meters to an outside
16 location. In addition, the Company has been making telephone calls, sending letters,
17 and making field visits to gain access to basement meters. In 2024, the average
18 number of meters not read was 1 meter, previously in 2023 the average was 2.

19 **4. Dispute Reporting**

20 When a customer registers a dispute with a utility about any matter covered
21 under Chapter 56 regulations, each utility covered by the regulations must issue its

1 report to the complaining party within 30 days of the initiation of the dispute
2 pursuant to 56.151 (5). In 2024, Columbia did not have any instance where a dispute
3 was not answered within 30 days.

4 **5. Customer Satisfaction**

5 **Q. Are there metrics that Columbia uses to gauge customer satisfaction and**
6 **the Company's effectiveness in providing quality customer service?**

7 A. Columbia uses a variety of methods to gather customer feedback. In addition to
8 performing a thorough review and analysis of the Commission's UCARE, the Quality
9 of Service Performance Report and the Universal Service and Collections Report,
10 Columbia uses three outside contractors to perform surveys to determine the
11 effectiveness of satisfaction reported by its customers. Those contractors are J.D.
12 Power, The MSR Group ("MSR") and Metrix Matrix. Columbia participates in the
13 J.D. Power Gas Residential Customer syndicated survey, utilizes the MSR group to
14 conduct a post-transaction satisfaction study and participates in the Metrix Matrix
15 study mandated by the Commission. Columbia also relies on an online residential
16 customer panel to help the Company incorporate customer feedback into improving
17 the customer experience.

18 **Q. Can you share the results of these surveys?**

19 A. Based on the results of the MSR survey, Columbia provided high quality service to its
20 customers in 2024. In 2024, Columbia's "First Contact Resolution" rate was 87.8%.
21 This statistic indicates the success that our call center CCC has had in satisfying

customers the first time they contact the Company. Figure 5 below, provides more detail on the service results Columbia achieved in this area in 2024.

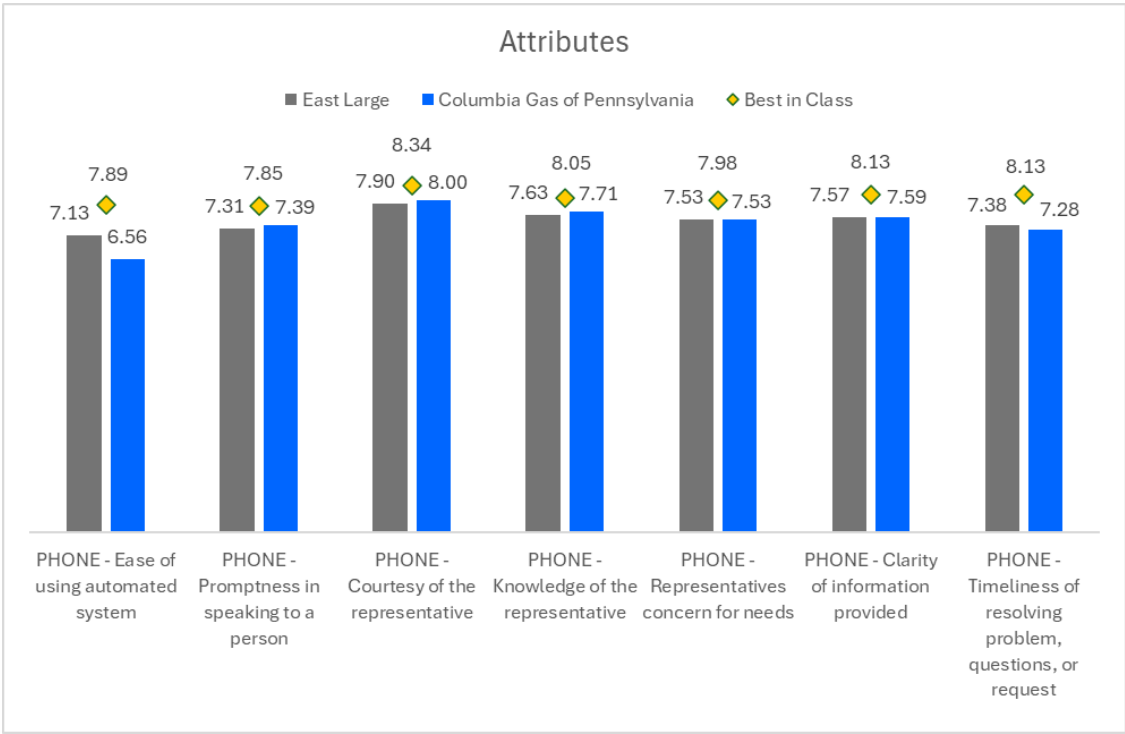
Figure 5

Phone Rep Performance	
YE 2024	
Overall satisfaction	90.7%
Put on hold after speaking with a rep	18.7%
Rep explained reason for hold	90.2%
Being courteous and professional	92.7%
Treated as a respected customer	93.2%
Showing concern for the situation	88.9%
Displaying knowledge in job	88.6%
Adequately answering questions	87.9%
How well rep listened to customer	92.7%
Having authority to make decisions	87.8%
Working quickly and efficiently	88.0%
Clarity of speech, speed, tone, and volume	92.9%
First contact resolution	87.8%

CPA Automated Phone Service	
YE 2024	
Overall satisfaction	71.1%
Ease of getting directly to information	72.1%
Ease of getting connected to live representative	71.4%
Amount of time required to complete the transaction	74.4%
IVR first contact resolution	63.1%

In addition to the MSR Survey, the Company's JD Power phone satisfaction score was 746, which ranks eighth place among thirteen companies in the East Large segment of peer gas utilities for this category. Telephone satisfaction is based on the attributes in Figure 6 below. Best in class represents the highest score for each attribute relative to based on the scores from the companies in the same segment.

Figure 6



Q. How well did Columbia perform on field service ratings?

A. As reflected in Figure 7 below, MSR results for Columbia's Field Service Representatives easily met the Company's 90%+ satisfaction threshold goal. The

following chart demonstrates that customers are satisfied with the level of service provided by Columbia employees working at their home or on their property.

Figure 7

CPA Field Visit Scheduling	
	YE 2024
Willing to accommodate needs	95.7%
Told when work would take place	96.6%
Arrived on time	96.9%
Total time to resolve	94.6%
CPA Field Service Performance Ratings	
	YE 2024
Overall satisfaction with performance	98.2%
Courteous and professional	98.7%
Displayed skill and knowledge	98.7%
Explained work being performed	97.7%
Adequately answered questions	97.7%
Aware of service performed	93.4%
Worked quickly and efficiently	98.7%
Being respectful of your property	98.5%
Left work property as found before work began	98.6%
Employees identified themselves	97.2%
Completed work on the first visit	93.8%

Q. How did Columbia perform in the 2024 J.D. Power Residential Customer Satisfaction Survey?

A. Columbia achieved an overall Customer Satisfaction Index score of 736 in the annual J.D. Power Gas Residential survey. In 2024, Columbia Gas of Pennsylvania moved into the East Large category from the East Midsize category in previous years. The Company outperformed the Large Eastern utility average of 730 by 6 points. In

1 addition, Columbia scored at or above the large eastern utility averages in Safety &
2 Reliability, Billing & Payment, and Customer Care.

3 **Q. What has been Columbia's success with implementing Chapter 14**
4 **Regulations?**

5 A. Over the past 20 years, Columbia has been successful in implementing the
6 Commission's Chapter 14 regulations, which provide the necessary tools to reduce
7 residential customer delinquency and write-offs. Based on data filed annually
8 pursuant to the Commission's regulations at Section 56.231, Columbia has reduced
9 its gross residential write-off ratio from 4.07% in 2005 to 2.0% in 2023. It also
10 reduced its net write-off for the same period from 2.79% to 1.37%.

11 **C. Process Improvements Enhancing Customer Service**

12 **Q. Can you describe any process improvements that Columbia has made to**
13 **better serve its customers?**

14 A. Columbia has continued to focus on providing a simple and seamless experience
15 for customers and will continue its focus to work across all business lines to further
16 strengthen and enhance relationships with its customers by proactively resolving
17 their concerns and making it easier to conduct business with us. Examples of
18 enhancements to improve customer interaction in 2024 includes:

- 19 • Continuation of new data-driven engagement strategy that Columbia initiated
20 in 2023 which uses analytical models to meet our customers' expectations
21 around service and value. The initiative enables us to connect with customers

1 to provide them with possible payment solutions before problems arise or assist
2 in arrears rehabilitation if the customer becomes delinquent. Communication
3 includes payment programs such as auto pay, budget billing, payment
4 reminders, energy assistance and payment plans. When comparing 2023 and
5 2024 data, the total arrears for all of Columbia's customers reduced by an
6 average of 21% month over month and the total arrears for residential
7 customers reduced by an average of 3% month over month.

- 8 • Our "Columbia Gas Mobile App" offers our customers another digital channel of
9 choice to perform self-service transactions. The mobile app serves all of
10 NiSource's Columbia states, including Pennsylvania, and it has more than
11 724,444 downloads across the NiSource footprint since it launched in August
12 2021. In 2024, we increased our push notification frequency from 720 push
13 notifications per hour to 300,000 notifications per hour. This change helps
14 ensure customers who are enrolled in push notification will receive the "Bill is
15 Ready" push notification in a timelier manner and lays the groundwork for
16 further push notification enhancements in the future. In 2024, more than 1.09
17 million transactions were completed across the NiSource footprint by Columbia
18 Gas customers in the app. The Columbia App has a rating of 4.8 out of 5 in the
19 App Store (iOS) and 4.6 out of 5 in Google Play (Android).
- 20 • The digital transaction self-service adoption rate across the NiSource footprint for
21 2024 across all digital channels (including payments) resulted in 83.1% of

1 transactions including digital payments being completed through self-service
2 options—Web, Mobile App, IVR, and Chatbots. Our Columbia mobile app has
3 had more than 724,444 downloads since it launched in August 2021, and we have
4 recorded more than 352,000 Start, Stop & Move transactions through the Service
5 Request Module since it went live in April 2021. These self-service options are
6 providing customers with a quick and easy way to service their Columbia account
7 - on their own time schedules - without necessitating a call to the call center.

- 8 • In 2024, Columbia Gas of Pennsylvania fielded 710,333 calls to our Interactive
9 Voice Response system (“IVR”). Of those calls, 47% (333,136 calls) were managed
10 within the automated phone system. The 11.6% drop in calls to the call center as
11 a result of the Company’s IVR between 2023 and 2024 is reflective of customers
12 continuing to adopt these self-service digital options for many of the more routine
13 questions and changes to their accounts, while customers with more involved and
14 complicated questions and account changes continue to call the call center.
- 15 • In February 2025, the Company launched a new IVR, Natural Interactive
16 Network Assistant (“NINA”). NINA will provide customers with conversational
17 Artificial Intelligence, new and enhanced conversational self-services and visual
18 IVR and text functionalities.

19 **D. Improvements Made for Customer, Employee and System Safety**

20 **Q. Besides customer service initiatives, is Columbia making any efforts to**
21 **improve customer, employee, and system safety?**

1 A. Yes, the Company works to continuously improve and add layers of protection to our
2 existing safety practices and build on the success of previous efforts. This includes
3 enhancements to processes, training, tools, and support, all of which are designed to
4 improve safety and eliminate high-consequence events. These efforts include:

- 5 • Quality Management and Oversight: The Quality Management organization
6 is responsible for systematically reviewing Gas Operations actions,
7 documentation, and processes to provide adequate proof and confidence
8 that work was completed, and tools/equipment were used in a safe and
9 compliant manner, per Company standards and state regulations.
10 Grounded in a risk-based strategy, the organization provides oversight of
11 critical tasks performed by our employees and contractors; executes field
12 and records audits to validate the quality of our work; and provides data on
13 outcomes and trends to interested stakeholders, linking findings and
14 corrective actions based on the riskiest work performed in the organization.
- 15 • Work Methods and Accelerator Knowledge Management System
16 technology: Columbia is developing and deploying digital “Work Methods”
17 via the Accelerator Knowledge Management System. These Work Methods
18 show not only the required steps but also incorporate important process
19 safety safeguards and layers of protection by requiring active verification of
20 step completion, active checks for abnormal conditions, and stop work flags
21 if certain expected conditions are not met during the course of work.

- “Incidents & Near Miss Reporting”: Columbia has implemented an event reporting tool to support event identification, event trending, causal evaluation, corrective action, and sharing of lessons learned to strengthen our ability to be a learning organization through consistent rigorous processes.

E. Serving Our Communities

Q. How does Columbia support the communities it serves?

A. Columbia is dedicated to investing in the communities it serves, and to helping enhance quality of life for our customers, as well as our employees. It is important to ensure that individuals and families within the communities we serve have what they need to thrive.

Each year, the NiSource Charitable Foundation⁴ has a mission to help create strong and sustainable communities where our employees and customers live and work. Columbia, in addition to the NiSource Charitable Foundation, donated more than \$633,000 in 2024 to 118 non-profit organizations throughout the 26-county and 450 community service area where we deliver natural gas. Donations supported basic needs and safety; Science, Technology, Engineering, and Math (STEM) and energy education; diversity, equity, and inclusion; environmental stewardship; and

⁴ Donations are made through the NiSource Charitable Foundation. Charitable contributions are not funded by customers through utility service rates. Charitable contributions are primarily funded by shareholders as a core part of the Company's commitment to support the communities and customers it serves.

1 economic and workforce development efforts in the communities we serve. We also
2 partner with community leaders and state, regional, and local economic development
3 organizations to attract new businesses and support the expansion of existing
4 businesses, while helping to create more jobs across the area.

5 Contributions made to the community by Columbia, its employees and the
6 NiSource Charitable Foundation in 2024 included the following:

- 7 • **American Red Cross:** The NiSource Charitable Foundation and
8 Columbia provided over \$50,000 to the American Red Cross to support
9 home safety programs in Pennsylvania in addition to our employees
10 organizing blood drives and donating locally.
- 11 • **Food Insecurity:** Due to the rise of inflation in our economy, Columbia
12 donated \$85,000 to local and regional food banks and organizations that
13 work to address the needs of those in local communities.
- 14 • **United Way Campaign:** Through the annual United Way campaign,
15 employees from Pennsylvania pledged over \$64,000 of their personal
16 income to local United Way chapters in support of education, financial
17 stability, and community health.
- 18 • **Energy Innovation Center:** The NiSource Charitable Foundation and
19 Columbia made a \$50,000 contribution and partnered with the Energy
20 Innovation Center in Pittsburgh, Pennsylvania, whose mission is to engage
21 community leaders to support minority-focused, post-secondary workforce

1 development training and education, and to develop and demonstrate
2 technology to support the emerging clean and sustainable energy market.

- 3 • **DEF:** Through donations and sponsorships, Columbia provided \$150,000
4 in support to the non-profit Dollar Energy Fund providing utility assistance
5 to income-eligible families experiencing hardship.

- 6 • **Dollars for Doers Program:** In addition to our Company's charitable
7 contributions, we partnered with our Pennsylvania employees to support
8 organizations which they are passionate about. More than \$99,000 of the
9 funding provided by the NiSource Charitable Foundation was given in
10 recognition of employee volunteerism through the Dollars for Doers
11 program in 2024. This program encourages employees to make a difference
12 in our communities by matching their volunteer hours with a financial
13 contribution to the Section 501(c)(3) non-profit organizations to which they
14 gave their time.

- 15 • **Employee Volunteerism:** Employees also participated in various
16 volunteer projects in partnership with Company initiatives. Our employees
17 assisted children to select new winter outerwear at three personal shopping
18 trips in Allegheny County, Beaver County, and Fayette County through the
19 Salvation Army and Project Bundle Up. In addition, employees volunteered
20 to help with a community clean-up and a tree planting with Allegheny Parks

Foundation and fundraised for a March of Dimes military baby shower for families in need.

F. Management Audit Performance

Q. How has Columbia performed relative to its peers from a Management Audit perspective?

A. In addition to Columbia's aggressive pipeline replacement program detailed in the testimony of Company witness Brumley at Columbia Statement No. 7, which demonstrates the effectiveness of Columbia's management and its concern for safety and excellence in customer service, Columbia has analyzed the most recent Management and Operations Audit reports from the Commission's website for Columbia, Peoples Natural Gas Company, Philadelphia Gas Works, UGI, National Fuel Gas and PECO. The data appears as Exhibit NP-1, which is attached to my testimony. Initially, I observe that the Commission's auditors employ a ranking category system that ranges from "Meets Expected Performance Level" to "Major Improvement Necessary" and they assign one of those ranking categories to various aspects of a utility company's management performance. Columbia evaluated the number of rankings categories for each gas distribution company mentioned and determined the number of times the Commission's auditors assigned each of the various ranking categories to a gas distribution company. They are set forth in Figure 8, below.

Figure 8
Summary of Most Recent
Commission Management and Operations Audit Results

Standard	Columbia	Peoples*	PGW	UGI	NFG	PECO
Meets Expected Performance	36%	27%	0%	0%	18%	55%
Minor Improvement Necessary	45%	27%	60%	55%	55%	27%
Moderate Improvement Necessary	18%	36%	30%	36%	18%	18%
Significant Improvement Necessary	0%	0%	10%	9%	9%	0%
Major Improvement Necessary	0%	9%	0%	0%	0%	0%
Total	100%	100%	100%	100%	100%	100%

* Peoples represents Peoples Natural Gas, the former Equitable Gas and Peoples TWP

As Figure 8 illustrates, Columbia achieved the “Meets Expected Performance Level” ranking category in 36% of the categories evaluated by the auditors, with one peer, PECO, scoring higher than Columbia. Also, Columbia was one of five gas companies that did not receive any ranking of either “Significant” or “Major” Improvement Necessary.

- III. Economic Development Distribution Service (“EDDS”) Rate Schedule**
- Q. Why is the Company seeking the addition of the EDDS rate schedule?**
- A. In January of 2024, Governor Shapiro and the Department of Community and Economic Development (DCED) created the Pennsylvania Economic Development Strategy, a comprehensive plan to guide the Commonwealth’s economic growth. The administration and DCED issued “A Ten-Year Strategic Plan for Economic

1 Development in Pennsylvania 2024 – 2033”⁵ to support Governor Shapiro’s vision
2 to make Pennsylvania a national leader in innovation, job creation, and economic
3 development while opening the doors of opportunity for Pennsylvania. The purpose
4 of this proposed rate schedule is to provide Columbia and large volume customers
5 the opportunity to work collaboratively to accelerate investment to support the
6 Governor Shapiro’s vision of economic growth in Pennsylvania.

7 The Company is seeking to implement this new rate schedule to allow the
8 flexibility to bring on new large load customers that may have short-term natural gas
9 or investment needs in a manner that provides for accelerated cost recovery while
10 protecting the interests of captive Columbia customers. This rate schedule will treat
11 these customers as non-jurisdictional customers and provide the opportunity for
12 Columbia to enter into individual contracts with customers taking service under this
13 rate schedule. The billing rate would reflect the cost to meet their individual needs
14 while separating those costs from the revenue requirement to be allocated to all other
15 customers.

16 **Q. Can you provide more detail on the types of customers that would take**
17 **service under this proposed rate schedule?**

18 A. Yes. The customers would include entities that will require large amounts of
19 electricity and are willing to develop capabilities to use natural gas to generate their
20 own electricity. Columbia anticipates that the proposed rate schedule would enable

⁵ <https://dced.pa.gov/newsroom/pennsylvania-gets-it-done-governor-josh-shapiro-launches-first-statewide-economic-development-strategy-in-nearly-two-decades/>

1 such companies to make the necessary investments to have gas service available for
2 their own on-site electric generation at new data centers, while shielding the
3 Company's captive customers from cost recovery associated with such investments.

4 **Q. What is the driving factor in adding this rate schedule to the tariff?**

5 A. While the Company currently does not have customers that have expressed an
6 interest in the service that would be provided by this rate schedule, Columbia submits
7 that the need for such a service is on the foreseeable horizon. The proposed rate
8 schedule would enable Columbia to meet the needs of large volume customers,
9 protect existing customers, and drive forward Governor Shapiro's Economic
10 Development Plan. This rate schedule would enable the Company to be prepared for
11 customers who are seeking regulatory environments in which the natural gas
12 industry has the flexibility in place to be able to serve their needs as soon as possible.

13 The electric industry is facing a constrained environment requiring
14 transmission and generation growth that can be arduous and slow to implement.
15 Large volume customers are focused on speed to market and need generation sooner
16 than many in the electric industry can provide. Due to this, customers are turning to
17 on-site natural gas generation to meet their electricity needs. This rate schedule will
18 provide a significant opportunity to potential customers who may not be able to
19 procure the power that they need from the traditional electric grid, while assisting
20 the Commonwealth of Pennsylvania to attract new business and while executing on
21 Governor Shapiro's Strategic Plan for Economic Development in Pennsylvania.

1 **Q. Why wouldn't other existing rate classes meet the needs of these**
2 **customers?**

3 A. A separate rate class ensures that costs incurred to provide service to an individual
4 customer are borne by that customer over the life the assets, even if the customer does
5 not utilize service over the life of the asset. To the extent facilities are constructed for
6 the benefit of individual customers and are not needed to maintain safe, reliable
7 service for retail customers, retail customers should be protected from having to pay
8 for them. Additionally, the capital investments associated with EDDS customers must
9 be maintained separately to ensure the Company's book depreciation is also
10 accelerated to match the customer billings. This ensures the full return of investment
11 is recovered from the EDDS customer and insulates the captive customers from being
12 allocated capital investments associated with these customers.

13 **Q. What facilities does the Company intend to use to serve customers**
14 **taking service under this rate schedule?**

15 A. The facilities used by EDDS customers will be unique to each situation. Facilities will
16 be impacted by the location of the facility and the needs of the customers. The
17 Company anticipates that, in most cases, new facilities will have to be constructed to
18 serve EDDS customers. Some EDDS customers may also require use of existing
19 equipment. In those cases, the EDDS customer would pay their share of the facilities
20 costs. Additionally, there may be scenarios in which the EDDS customer needs to
21 pay for improvements to a point of delivery or require other betterment to the system,

1 which would benefit other customers on the system.

2 **Q. How would costs associated with constructing new facilities for**
3 **customers taking service under this rate schedule be treated?**

4 A. Costs would be separated into jurisdictional and non-jurisdictional costs. To the
5 extent that the new facilities are constructed solely for the use of an EDDS customer,
6 those costs will be considered non-jurisdictional and such costs will be directly
7 assigned to the EDDS customer. Where facilities provide a benefit for EDDS
8 customers and other customers, costs will be allocated based on the benefit provided.
9 Costs provided to customers other than EDDS customers would be considered
10 jurisdictional costs. Accurate allocation of costs will be critical to ensure that costs
11 are recovered. At the inception of the contract, all costs of service will be taken into
12 consideration to determine the amount to be charged to the EDDS customer over the
13 life of the contract. To the extent that an EDDS rate is not adequate to cover the cost
14 of service, bifurcation of jurisdictional and non-jurisdictional costs ensures that
15 jurisdictional customers will not be impacted by costs that do not benefit them.

16 **Q. Would EDDS customers be responsible for betterment of the system?**

17 A. Betterment of the system would be determined on a case-by-case basis. Through the
18 engineering process, Columbia would assess the EDDS customer's impact on the
19 system. If the engineering process determines that the EDDS customer effected the
20 jurisdictional customers in a detrimental manner, then a betterment project would
21 be allocated to the EDDS customer.

1 **Q. How does separate allocation of costs related to EDDS customers**
2 **protect customers in all the other rate classes?**

3 A. Accounting for costs related to EDDS customers separately will protect all other
4 customers from the risk of the EDDS customers leaving the system. Under the typical
5 regulatory construct, the capital investment would be placed in service, added to rate
6 base and costs would be allocated to all customers, and if the large load customers no
7 longer take service, all remaining customers would continue to pay for the capital
8 outlay over the life of the assets. Treating costs associated with EDDS customers
9 separately from all other customers will shield them from the risk of EDDS customers
10 leaving the system. In other words, the Company bears all the risk of the EDDS
11 customer leaving. Separation of costs related to EDDS customers ensures that the
12 jurisdictional customers' bills will not be increased due to the additional capital
13 investment.

14 **Q. Would adding an EDDS customer as non-jurisdictional reduce the**
15 **revenue requirement for jurisdictional customers?**

16 A. Yes. Holding all else equal, adding an EDDS customer while assigning direct and
17 allocating non-direct cost to the EDDS through the non-jurisdictional process would
18 reduce the applied revenue requirement for all jurisdictional customers, as some
19 costs may be allocated between both jurisdictional and non-jurisdictional customers.
20 One example of how the jurisdictional customers revenue requirement would be
21 reduced would be through labor costs. To the extent that resources serve both

jurisdictional and non-jurisdictional customers, labor for the jurisdictional customers would be reduced to reflect the allocation of labor to the EDDS customer.

Q. How would the Company allocate costs between EDDS customers and all other customers?

A. The Company would perform a Jurisdictional Allocated Cost of Service Study, that will allocate and assign the Company's total cost of service for the test year to two groups of customers: (1) the customers who contract for EDDS service (2) all other customers.

Q. What are the primary steps in performing the Jurisdictional Study?

A. The Jurisdictional Study will be structured to accept accounting data under the FERC three-digit account designations for plant, rate base, and income statement accounts. The first step is to identify and direct assign the gas plant facilities serving all EDDS customers. The capitalized investment for these facilities will be identified and isolated on Columbia's plant accounting record. These facilities will be designed for the use of the particular customer and can be directly assigned. The next step is to assign allocation factors for each element of costs to allocate common facilities between retail gas customers classified as non-jurisdictional and jurisdictional customers. The allocation factors chosen for these allocations will be the same factors used in the Allocated Cost of Service Study.

Q. Do you have an example of a Jurisdictional Study?

1 A. Yes, an illustrative example of a Jurisdictional Study is provided in Exhibit NP-2.⁶
2 This study consists of pages 1 through 11 showing Total Company costs and how
3 those costs are separated between jurisdictional and non-jurisdictional (EDDS)
4 customers and pages 12 and 13 showing the allocation factors. The Jurisdictional
5 Study also shows, starting on page 3, the allocation percentage for each line that is
6 allocated. This demonstrates that a portion of costs, such as operation and
7 maintenance expense on page 7, will be charged to the non-jurisdictional
8 customers, therefore lowering the costs of jurisdictional customers.

9 **Q. How will the company allocate costs between jurisdictional and non-**
10 **jurisdictional customers?**

11 A. As each project will be unique, allocation will be done on a case-by-case basis
12 dependent upon the benefits received by each group of customers from the
13 facilities. For purposes of Columbia's rate case filings, the Company will provide a
14 composite of the allocation for all EDDS customers as illustrated in Exhibit NP-2.

15 **Q. Please describe the relevant factors for the Commission to determine**
16 **that the Company's EDDS proposal is just and reasonable.**

17 A. Each policy factor relevant to the Commission's evaluation is discussed below, along
18 with the specific impact of Columbia's EDDS proposal on each consideration. The
19 following fourteen items align with the considerations identified within the

⁶ This study is for illustrative purposes only and the numbers utilized in this study are not based on any actual financial data.

1 Statement of Policy as outlined by the Commission in the alternative rate making
2 Docket No. M-2015-2518883⁷. As the Commission noted at page 20 of its Final
3 Policy Statement Order in that proceeding, “not all of the 14 considerations are
4 applicable to all alternative ratemaking mechanisms or rate designs to all utilities.”

5 1. **Alignment with Cost Causation Principles:** As discussed above, Columbia
6 has designed its proposal so that the recovery of costs associated with providing
7 EDDS would be borne by customers receiving that service.

8 2. **Impact on Fixed Utility’s Capacity Utilization:** This consideration is not
9 applicable to Columbia’s EDDS proposal.

10 3. **Reflection of Demand Associated with the Customer’s Anticipated**
11 **Consumption:** As discussed above, Columbia’s proposed EDDS rate schedule
12 will provide a significant opportunity to potential customers who may not be able
13 to procure the power that they need from the traditional electric grid, while
14 assisting the Commonwealth of Pennsylvania to attract new business and while
15 executing on Governor Shapiro’s Strategic Plan for Economic Development in
16 Pennsylvania.

17 4. **Limiting Inter-Class and Intra-Class Cost Shifting:** As discussed above,
18 Columbia has designed its proposal so that the recovery of costs associated with
19 providing EDDS would be borne by customers receiving that service.

⁷ 52 Pa. Code § 69.3302.

1 **5. Eliminates Disincentive for Promotion of Energy Efficiency and**

2 **Conservation Programs:** This consideration is not applicable to Columbia's
3 EDDS proposal.

4 **6. Customer Incentives for Efficiency and Distributed Energy Resources:**

5 This consideration is not applicable to Columbia's EDDS proposal.

6 **7. Impact on Low-Income Customers:** Columbia's proposed EDDS rate
7 schedule will have no impact on low-income customers.

8 **8. Rate Stability:** Columbia's proposed EDDS rate schedule promotes rate stability
9 by treating costs associated with EDDS customers separately from all other
10 customers and will shield them from the financial risk of EDDS customers leaving
11 the system. In other words, the Company bears all the risk of the EDDS customer
12 leaving. Separation of costs related to EDDS customers ensures that the
13 jurisdictional customers' bills will not be increased due to the additional capital
14 investment.

15 **9. Interaction with Weather:** This consideration is not applicable to Columbia's
16 EDDS proposal.

17 **10. Impacts on the Frequency of Rate Case Filings and Regulatory Lag:** This
18 consideration is not applicable to Columbia's EDDS.

19 **11. Interaction with Other Revenue Sources:** As discussed above, the Company
20 would perform a Jurisdictional Allocated Cost of Service Study, that will allocate
21 and assign the Company's total cost of service for the test year to two groups of

1 customers: (1) the customers who contract for EDDS service (2) all other
2 customers.

3 **12. Consumer Protections:** As discussed above, Columbia has designed its EDDS
4 proposal to enable large customers to make the necessary investments to have gas
5 service available for their own on-site electric generation while shielding the
6 Company's captive customers from cost recovery associated with such investment.

7 **13. Complexity and Customer Understanding:** Columbia submits that its
8 proposal is straightforward, is not complex, and would be readily understood by
9 its customers. Moreover, to the extent that it would be considered to be complex,
10 Columbia submits that the large customers that it is designed to serve would have
11 the necessary sophistication to understand it.

12 **14. Utility Reliability Improvement Support:** The proposed EDDS supports the
13 Company's reliability improvements by ensuring stable and predictable cost
14 recovery. Further, as discussed above, for customers who are turning to on-site
15 natural gas generation to meet their electricity needs, this rate schedule will
16 provide a significant opportunity to potential customers who may not be able to
17 procure the power that they need from the traditional electric grid, while assisting
18 the Commonwealth of Pennsylvania to attract new business and while executing
19 on Governor Shapiro's Strategic Plan for Economic Development in Pennsylvania.

20 **Q. Does this complete your Prepared Direct Testimony?**

21 A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Exhibit I – 1 Columbia Gas of Pennsylvania, Inc. Management and Operations Audit Functional Area Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure		X			
Corporate Governance		X			
Affiliated Interests and Cost Allocations			X		
Financial Management		X			
Gas Operations	X				
Customer Service			X		
Purchasing and Materials Management	X				
Emergency Preparedness	X				
Human Resources		X			
Fleet Management		X			
Information Technology	X				

D. Benefits

Where possible, the auditors estimated the potential savings expected from implementing the recommendations made in this report. The audit report contains potential cost savings of \$272,000 to \$332,000, annually. We tried to identify, whenever practical, the potential savings, net of the projected costs, for implementation. Some of these savings could be an actual reduction in costs, avoided costs, or increased revenues; whereas, others would result in better deployment and/or use of existing resources. These quantifications require some judgment and may require efforts beyond the scope of the audit for further refinement. Therefore, actual benefits from effective implementation of the recommendations are subject to uncertainty and could be higher or lower than the estimate. An overall summary of the annual and one-time costs savings quantified in the audit report are shown in Exhibit I – 2 on the next page.

COLUMBIA GAS OF PENNSYLVANIA, INC.

Exhibit I – 2 Columbia Gas of Pennsylvania, Inc. Management and Operations Audit Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Implement various strategies to reduce arrearage levels such as increasing CAP enrollment and effective calculation of internal arrearage data to appropriately monitor and manage arrearage performance. (VIII – 2)	\$92,000	
Complete an analysis of the third-party retention application to evaluate program efficacy in reducing CSR turnover rates by December 31, 2020. (VIII – 5)	\$180,000 - \$240,000	
Total	\$272,000 - \$332,000	-

For most of the recommendations, it was impractical to estimate quantitative benefits as the benefits are of a qualitative nature, or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist nor was not fully functional. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a function but cannot be easily quantified.

CPA will have options to implement the recommendations and, as a result, the auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted that the cost of implementing some recommendations could be significant.

E. Recommendation Summary

Chapters III through XIII provide conclusions, findings, and recommendations for each functional area reviewed in-depth during this audit. Exhibit I – 3 summarizes the recommendations with the following priority assessments for implementation:

- **INITIATION** – Estimated time frame for how quickly CPA should be able to initiate its implementation efforts given CPA's resources and general operating environment. The time necessary to complete implementation will vary depending on the nature of the recommendation, the scope of the efforts necessary, and resources available to implement the recommendation.

COLUMBIA GAS OF PENNSYLVANIA, INC.

- **BENEFITS** – Net quantifiable benefits are provided, where they could be estimated, as discussed in Section D – Benefits. Our estimated overall level of benefit rankings is not solely based on quantifiable dollars but considers the auditors' assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of CPA and/or the services it provides.
- **HIGH BENEFIT** – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.
 - **MEDIUM BENEFIT** – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.
 - **LOW BENEFIT** – Implementation of the recommendation is likely to result in service improvements, improvements in management practices and performance, and/or enhanced cost controls.

Exhibit I-1
Aqua Pennsylvania, Inc.
The Peoples Companies
Functional Area Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Aqua Pennsylvania, Inc.					
Executive Management and Organizational Structure			X		
Corporate Governance		X			
Affiliated Interests and Cost Allocations			X		
Financial Management		X			
Water Operations			X		
Emergency Preparedness			X		
Materials Management		X			
Customer Service		X			
Information Technology	X				
Fleet Management		X			
Human Resources and Diversity	X				
The Peoples Companies					
Executive Management and Organizational Structure	X				
Corporate Governance			X		
Affiliated Interests and Cost Allocations					X
Financial Management			X		
Gas Operations			X		
Emergency Preparedness	X				
Materials Management		X			
Customer Service		X			
Information Technology	X				
Fleet Management		X			
Human Resources and Diversity			X		

D. Benefits

Wherever possible, the audit staff estimated the potential savings expected from implementing the recommendations made in this report. The audit report details potential savings of approximately \$417,000 annually with \$339,000 and \$78,000 attributed to Aqua PA and the Peoples Companies, respectively. We tried to identify, whenever practical, the potential savings, net of the projected costs, for implementation. Some of these savings could be an actual reduction in costs, avoided costs, or increased revenues; whereas, others would result in better deployment and/or use of existing resources. These quantifications require some judgment and may require efforts beyond the scope of the audit for further refinement. Therefore, actual benefits from effective implementation of the recommendations are subject to uncertainty and

could be higher or lower than the estimate. An overall summary of the annual and one-time costs savings quantified in the audit report are shown in Exhibit I-2, below.

Exhibit I-2
Aqua Pennsylvania, Inc. & The Peoples Companies
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Aqua PA		
Document all lease agreements between Aqua PA and its affiliates and submit them to the Commission for approval. (V-2)	\$150,000	-
Focus efforts on reducing NRW at the Roaring Creek system. (VII-5)	\$189,000	-
Aqua PA Subtotal	\$339,000	-
Peoples Companies		
Benchmark with similar utilities to set separate net collection goals for primary and secondary collection agencies at the Peoples Companies and measure each collection agency to the respective collection goal. (XI-4)	PNGC: \$51,000 PGC: \$27,000	-
Peoples Companies Subtotal	\$78,000	-
Total for All Companies	\$417,000	-

For most recommendations, it was impractical to estimate quantitative benefits as the benefits are of a qualitative nature, or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist nor was not fully functional. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a function but cannot be easily quantified.

Aqua PA and/or the Peoples Companies will have options to implement the recommendations and, as a result, the audit staff have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted that the cost of implementing some recommendations could be significant.

E. Current Events

On March 6, 2020, the Governor of Pennsylvania, Tom Wolf, declared a disaster emergency due to the COVID-19 pandemic. This and other state government actions ordered all but essential businesses and their operations closed for the safety of the general public. Although fixed utility operations such as water treatment and gas distribution were considered essential, most of the back-office functions such as corporate management, accounting and government relations were deemed nonessential. Most Pennsylvania utilities closed their business offices and allowed their employees to work remotely. The Pennsylvania Public Utility Commission also closed the main office and allowed employees, including those of the Audit Bureau, to perform their functions remotely. All nonessential travel and in-person meetings were prohibited.

As such, the COVID-19 crisis affected the approach and timeline of the audit. For example, some interviews and data request responses were delayed or modified. In all cases, the audit staff worked with Aqua PA and the Peoples Companies to acquire information needed to issue the findings and recommendations contained within this report. Although some aspects of fieldwork were modified and/or unfeasible, we worked to minimize the impact to the conclusions presented within the report. We believe that our procedures sufficiently mitigate the audit risk associated with altering our standard practices. However, conclusions presented within this report may change if additional information is made available. Furthermore, it is important to note that although COVID-19 affected the companies' operations; this report does not, nor was it intended to reflect any modified operations.

F. Recommendation Summary

Chapters III through XIV provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this focused audit. Exhibit I-3 summarizes the recommendations with the following priority assessments for implementation:

- **INITIATION TIME FRAME** – Estimated time frame on how quickly the Company should be able to initiate its implementation efforts given the Company's resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation and the scope of the efforts necessary and resources available to effectively implement the recommendation.
- **BENEFITS** – Net quantifiable benefits have been provided where they could be estimated as discussed in Section D - Benefits. Our overall rankings are not solely based on quantifiable dollars but rather our assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of the Company and/or the services it provides.

- HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.
- MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.
- LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

Exhibit I-1
UGI Utilities, Inc.
Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure		X			
Corporate Governance		X			
Affiliated Interests and Cost Allocations			X		
Financial Management		X			
Gas Operations			X		
Electric Operations		X			
Emergency Preparedness				X	
Materials Management			X		
Information Technology		X			
Customer Service			X		
Fleet Management		X			
Human Resources / Diversity		X			

D. Benefits

Where possible, the auditors quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. The audit report contains identifiable potential quantifiable cost savings of \$336,090 to \$713,019 in annual savings and \$3,360,900 to \$7,130,196 in one-time savings from effective implementation of the recommendations. We identify, whenever it is reasonably practical, the potential savings net of the projected costs for implementation. Some of these savings could be considered an actual reduction in costs, avoided costs or increased revenues; whereas others would result from better deployment and/or use of existing resources. These quantifications require some judgment and may require efforts beyond the scope of the audit for further refinement. Therefore, the actual benefits from effective implementation of the recommendations are subject to some degree of uncertainty and could be higher or lower than the amounts estimated by the auditors. An overall summary of the annual and one-time cost savings quantified in the audit report are shown in Exhibit I-2.

Exhibit I-2
UGI Utilities, Inc.
Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
X-1. Improve company-wide inventory turnover and exclude emergency stock from inventory turnover calculations.	\$336,090 - \$713,019	\$3,360,900 - \$7,130,196

For most of the recommendations, it is not possible or practical to estimate quantitative benefits as they are of a qualitative nature or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a specific function but cannot be easily quantified.

UGI Utilities will have options to implement the recommendations and so the auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted to the reader that the cost of implementing certain recommendations could be significant.

E. Recommendation Summary

Chapters III through XIV detail the findings, conclusions and recommendations for each function or area reviewed in-depth during this audit. Exhibit I-3 summarizes the recommendations with the following priority assessments for implementation:

- **INITIATION TIME FRAME** – Estimated time frame for how quickly UGI Utilities should be able to initiate its implementation efforts, given UGI Utilities' resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation, the scope of the efforts necessary, and resources available to effectively implement the recommendation.
- **BENEFITS** – Net quantifiable benefits have been provided, where they could be estimated, as discussed in Section D - Benefits. Our estimated overall level of benefits rankings is not solely based on quantifiable dollars, but the auditor's assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of UGI Utilities, and/or the services it provides. In addition, the ratings weight the avoidance of future adverse conditions based upon the potential severity of the adverse condition. In this form, high consequence conditions could

garner a higher benefit rating than conditions occurring frequently but with a lower impact.

- HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, avoidance of substantial consequences, and/or significant cost savings.
- MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, avoidance of unfavorable but manageable consequences, and/or meaningful cost savings.
- LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

operating given the company's resources and general operating environment. Expected performance is not a "cutting edge" operating condition; rather, it is management of a functional area such that produces reasonably expected operating results.

Listed below are the categories used to rate each functional area's operating or performance level:

- Meets Expected Performance Level
- Minor Improvement Necessary
- Moderate Improvement Necessary
- Significant Improvement Necessary
- Major Improvement Necessary

Our rating for each reviewed functional area is presented in Exhibit I-1.

Exhibit I-1
National Fuel Gas Distribution Corporation
Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure	X				
Corporate Governance		X			
Affiliated Interests and Cost Allocations			X		
Financial Management			X		
Gas Operations				X	
Customer Service		X			
Purchasing and Materials Management		X			
Emergency Preparedness		X			
Human Resources and Diversity		X			
Fleet Management	X				
Information Technology		X			

D. Benefits

Wherever possible, the PUC auditors estimated the potential savings anticipated from implementing the recommendations made in this report. The audit report details potential annual cost savings of approximately **\$3.1 million**. We tried to identify, whenever practical, the potential savings through recommendation implementation. Some of these savings could be an actual reduction in costs, avoided costs, or increased revenues, whereas others would result in better deployment and/or use of

existing resources. These quantifications require some judgment and may require effort beyond the scope of the audit for further refinement. Therefore, actual benefits from effective implementation of the recommendations are uncertain and could differ from the estimate. An overall summary of the annual and/or one-time costs savings quantified in the audit report is shown in Exhibit I-2.

**Exhibit I-2
National Fuel Gas Distribution Corporation
Quantifiable Savings Summary**

Recommendation	Annual Savings	One-Time Savings
Analyze and improve the billing process to reduce billing lag and decrease associated interest expense. (VI – 2)	\$ 1,500,000	
Acquire and implement automated metering technology. (VII – 1)	1,400,000	
Track billing adjustments by reason to identify potential process improvements to decrease the number of billing adjustments. (VIII – 1)	122,000	
Analyze safety incident root cause data to identify areas of improvement for training and safety programs and enhance enforcement procedures to appropriately motivate employee compliance. (XI – 3)	86,000	
Totals	\$ 3,108,000	---

For most recommendations, it was impractical to estimate quantitative benefits as the benefits are of a qualitative nature or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist nor were not fully functional. Similarly, changes in workflow or implementation of good business practices could result in improved efficiency and effectiveness of a function but cannot be easily quantified.

NFGDC-PA will have options to implement the recommendations, and as a result, the PUC auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted that the cost of implementing some recommendations could be significant.

E. Recommendation Summary

Chapters III through XIII provide findings, conclusions, and recommendations for each functional area reviewed in-depth during this audit. Exhibit I-3 summarizes the recommendations with the following priority assessments for implementation:

- INITIATION TIME FRAME – Estimated time frame on how quickly the company should be able to initiate its implementation efforts given the company's resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation and the scope of the effort necessary and resources available to effectively implement the recommendation.
- BENEFITS – Net quantifiable benefits have been provided where they could be estimated as discussed in section D. Benefits. Our overall rankings are not solely based on quantifiable dollars but rather our assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of the company and/or the services it provides.
 - HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.
 - MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.
 - LOW BENEFITS – Implementation of the recommendation is likely to result in service, management practice, and/or performance improvements and/or enhanced cost controls.

**Exhibit I-1
Philadelphia Gas Works
Management and Operations Audit
Functional Rating Summary**

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Corporate Governance			X		
Executive Management and Organizational Structure		X			
Financial Management		X			
Gas Operations			X		
Emergency Preparedness				X	
Materials Management		X			
Customer Service			X		
Information Technology		X			
Fleet Management		X			
Human Resources and Diversity		X			

D. Benefits

Where possible, the audit staff attempt to quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. However, for most recommendations, it was impractical to estimate quantitative benefits as the benefits are of a qualitative nature, or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist or were not fully functional. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a function but cannot be easily quantified.

The company will have options to implement the recommendations and, as a result, the PUC auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted that the cost of implementing some recommendations could be significant.

E. Current Events

On March 6, 2020, the Governor of Pennsylvania, Tom Wolf, declared a disaster emergency due to the COVID-19 pandemic. This and other state government actions ordered all but essential businesses and their operations closed for the safety of the general public. Although fixed utility operation such as gas distribution was considered

essential, most of the back-office functions such as corporate management, accounting and government relations were deemed nonessential. Most Pennsylvania utilities closed their business offices and allowed their employees to work remotely. The Pennsylvania Public Utility Commission also closed the main office and allowed employees, including those of the Audit Bureau, to perform their functions remotely. All nonessential travel and in-person meetings were prohibited.

As such, the COVID-19 crisis affected the operation and data contained within this audit. In addition, where needed the approach and timeline of the audit was changed to accommodate lingering COVID-19 implications. For example, some interviews and data request responses were delayed or modified. In all cases, the audit staff worked with PGW to acquire information needed to issue the findings and recommendations contained within this report. We believe that our procedures sufficiently mitigate the audit risk associated with altering our standard practices to address COVID-19's impact to the company or our audit. However, conclusions presented within this report may change if additional information is made available.

F. Recommendation Summary

Chapters III through XII provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this audit. Exhibit I-3 summarizes the recommendations with the following priority assessments for implementation:

- **INITIATION TIME FRAME** – Estimated time frame on how quickly the company should be able to initiate its implementation efforts given the company's resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation and the scope of the efforts necessary and resources available to effectively implement the recommendation.
- **BENEFITS** – Net quantifiable benefits have been provided where they could be estimated as discussed in Section D - Benefits. Our overall rankings are not solely based on quantifiable dollars but rather our assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of the company and/or the services it provides.
 - **HIGH BENEFITS** – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.
 - **MEDIUM BENEFITS** – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.

- LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

Exhibit I-1
PECO Energy Company
Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure	X				
Corporate Governance	X				
Affiliated Interests and Cost Allocations			X		
Financial Management	X				
Electric Operations			X		
Gas Operations			X		
Emergency Preparedness		X			
Materials Management	X				
Customer Service		X			
Information Technology	X				
Fleet Management	X				
Human Resources and Diversity		X			

D. Benefits

Where possible, the audit staff attempts to quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. The audit report contains identifiable potential quantifiable cost savings of approximately \$15 million in annual savings and \$13,581,327 in one-time savings from effective implementation of the recommendations. We try to identify, whenever it is reasonably practical, the potential savings net of the projected costs for implementation. Some of these savings could be considered an actual reduction in costs, avoided costs or increased revenues, whereas others would result from better deployment and/or use of existing resources. These quantifications require some judgment and may require efforts beyond the scope of the audit for further refinement. Therefore, the actual benefits from effective implementation of the recommendations are subject to some degree of uncertainty and could be higher or lower than the amounts estimated by the audit staff. An overall summary of the annual and one-time cost savings quantified in the audit report are shown in Exhibit I-2.

Exhibit I-2
PECO Energy Company
Management and Operations Audit
Quantifiable Savings Summary

Recommendation	Annual Savings	One-Time Savings
Submit a detailed proposal to the Commission for the appropriate crediting of ratepayers due to PECO's corrected billings for the use of PECO's fiber network. (V-1)	-	\$13,581,327
Reduce Electric operations staff overtime to 15% overtime hours per normal hours worked or less. (VI-1)	Up to \$15,000,000	-
Reduce Gas Operations staff overtime to 15% overtime hours per normal hours worked or less. (VII-3)	(a subset of \$15,000,000 in VI-1)	-
Totals	\$15,000,000	\$13,581,327

For most recommendations, it was impractical to estimate quantitative benefits as the benefits are of a qualitative nature, or insufficient data was available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist or were not fully functional. Similarly, changes in workflow or implementation of good business practices could result in improved effectiveness and efficiency of a function but cannot be easily quantified.

The company will have options to implement the recommendations and, as a result, the PUC auditors have not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted that the cost of implementing some recommendations could be significant.

E. Current Events

On March 6, 2020, the Governor of Pennsylvania, Tom Wolf, declared a disaster emergency due to the COVID-19 pandemic. This and other state government actions ordered all but essential businesses and their operations closed for the safety of the general public. Although fixed utility operations such as electric distribution and gas distribution were considered essential, most of the back-office functions such as corporate management, accounting and government relations were deemed nonessential. Most Pennsylvania utilities closed their business offices and allowed their employees to work remotely. The Pennsylvania Public Utility Commission also closed the main office and allowed employees, including those of the Audit Bureau, to perform their functions remotely. All nonessential travel and in-person meetings were prohibited.

As such, the COVID-19 crisis affected the approach and timeline of the audit. For example, some interviews and data request responses were delayed or modified. In all cases, the audit staff worked with PECO Energy Company to acquire information needed to issue the findings and recommendations contained within this report. Although some aspects of fieldwork were modified and/or unfeasible, we worked to minimize the impact to the conclusions presented within the report. We believe that our procedures sufficiently mitigate the audit risk associated with altering our standard practices. However, conclusions presented within this report may change if additional information is made available. Furthermore, it is important to note that although COVID-19 affected the companies' operations; this report does not, nor was it intended to evaluate modifications to operations.

F. Recommendation Summary

Chapters III through XV provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this audit. Exhibit I-3 summarizes the recommendations with the following priority assessments for implementation:

- INITIATION TIME FRAME – Estimated time frame on how quickly the company should be able to initiate its implementation efforts given the company's resources and general operating environment. The time necessary to complete implementation is expected to vary depending on the nature of the recommendation and the scope of the efforts necessary and resources available to effectively implement the recommendation.
- BENEFITS – Net quantifiable benefits have been provided where they could be estimated as discussed in Section D - Benefits. Our overall rankings are not solely based on quantifiable dollars but rather our assessment of the potential overall impact of the recommendation on the efficiency and/or effectiveness of the company and/or the services it provides.
 - HIGH BENEFITS – Implementation of the recommendation would result in major service improvements, substantial improvements in management practices and performance, and/or significant cost savings.
 - MEDIUM BENEFITS – Implementation of the recommendation would result in important service improvements, meaningful improvements in management practices and performance, and/or meaningful cost savings.
 - LOW BENEFITS – Implementation of the recommendation is likely to result in service improvements, management practices and performances, and/or enhance cost controls.

COLUMBIA GAS OF PENNSYLVANIA, INC.
ALLOCATED COST OF SERVICE - JURISDICTIONAL - TABLE OF CONTENTS

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For Illustrative Purposes Only

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1	TABLE OF CONTENTS
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3	RATE OF RETURN BY CLASS - CURRENT @ CURRENT RATES - JURISDICTIONAL
4	GROSS PLANT (Accounts 101 & 106) - JURISDICTIONAL
5	DEPRECIATION RESERVE - JURISDICTIONAL
6	DEPRECIATION AND AMORTIZATION EXPENSE - JURISDICTIONAL
7	OPERATING REVENUE @ PROPOSED & CURRENT RATES - JURISDICTIONAL
8	PRODUCTION & DISTRIBUTION O&M EXPENSES - JURISDICTIONAL
9	OTHER O&M EXPENSES - JURISDICTIONAL
10	TAXES OTHER THAN INCOME TAXES - JURISDICTIONAL
11	RATE BASE - JURISDICTIONAL
12	STATE/FEDERAL INCOME TAXES - JURISDICTIONAL
13	ALLOCATION FACTORS - JURISDICTIONAL
14	ALLOCATION FACTORS (CONT.) - JURISDICTIONAL

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - PROFORMA @ PROPOSED RATES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

Exhibit NP-2
Page 2 of 14

ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY
PEAK & AVERAGE

For Illustrative Purposes Only

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) \$	EDDS (D) \$	JURISDICTIONAL (E) \$
1	TOTAL REVENUE [PAGE 6]		320,312,000	5,000,001	315,311,999
2	PRODUCTS PURCHASED [PAGE 7]		100,000,000	0	100,000,000
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		77,512,300	2,309,611	75,202,689
4	DEPRECIATION & AMORTIZATION [PAGE 5]		42,732,300	168,392	42,563,908
5	TAXES OTHER THAN INCOME [PAGE 9]		<u>2,111,000</u>	<u>50,301</u>	<u>2,060,699</u>
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		222,355,600	2,528,304	219,827,296
7	OPERATING INCOME BEFORE TAXES		97,956,400	2,471,697	95,484,703
8	INCOME TAXES		31,765,479	831,849	30,933,629
9	INVESTMENT TAX CREDIT	DIRECT	<u>(100,000)</u>	<u>0</u>	<u>(100,000)</u>
10	NET INCOME TAXES		31,665,479	831,849	30,833,629
11	OPERATING INCOME		66,290,922	1,639,848	64,651,074
12	RATE BASE [PAGE 10]		1,160,104,010	47,397,617	1,112,706,393
13	RATE OF RETURN EARNED ON RATE BASE		5.714%	3.460%	5.810%
14	UNITIZED RETURN		1.00000	0.60553	1.01680

COLUMBIA GAS OF PENNSYLVANIA, INC.
 RATE OF RETURN BY CLASS - CURRENT @ CURRENT RATES
 FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

Exhibit NP-2
 Page 3 of 14

ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY
 PEAK & AVERAGE

For Illustrative Purposes Only

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) \$	EDDS (D) \$	JURISDICTIONAL (E) \$
1	TOTAL REVENUE [PAGE 6]		320,312,000	5,000,001	315,311,999
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7	OPERATING INCOME BEFORE TAXES		97,956,400	2,471,697	95,484,703
8	INCOME TAXES [PAGE 11]		31,765,479	831,849	30,933,629
9	INVESTMENT TAX CREDIT	DIRECT	<u>(100,000)</u>	<u>0</u>	<u>(100,000)</u>
10	NET INCOME TAXES		31,665,479	831,849	30,833,629
11	OPERATING INCOME		66,290,922	1,639,848	64,651,074
12	RATE BASE [PAGE 10]		1,160,104,010	47,397,617	1,112,706,393
13	RATE OF RETURN EARNED ON RATE BASE		5.714%	3.460%	5.810%
14	UNITIZED RETURN		1.00000	0.60553	1.01680

COLUMBIA GAS OF PENNSYLVANIA, INC.
GROSS PLANT (Accounts 101 & 106)
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

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ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY PEAK & AVERAGE				For Illustrative Purposes Only				
LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) \$	EDDS (E) \$	EDDS PERCENT (F)	JURISDICTIONAL (G) \$	JURISDICTIONAL PERCENT (H)
1	301-305	INTANGIBLE PLANT	DIRECT	100,000,000	100,000		99,900,000	
2	350-362	UNDERGROUND STORAGE PLANT	DIRECT	10,000,000	0		10,000,000	
		<u>DISTRIBUTION PLANT</u>						
3	374.10	LAND - CITY GATE & M/L IND M&R	DIRECT	10,000	0		10,000	
4	374.20	LAND - OTHER DISTRIBUTION	DIRECT	1,000,000	1,000		999,000	
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	DIRECT	100,000	0		100,000	
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	DIRECT	10,000,000	100		9,999,900	
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	DIRECT	100,000	0		100,000	
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	DIRECT	10	0		10	
9	374.50	RIGHTS OF WAY	DIRECT	1,000,000	100,000		900,000	
10	374.50	DIRECT - RIGHTS OF WAY	DIRECT	0	0		0	
11	375.20	M & R STRUCTURES - CITY GATE	DIRECT	10,000	0		10,000	
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	DIRECT	1,000	0		1,000	
13	375.40	M & R STRUCTURES - REGULATING	DIRECT	10,000,000	100,000		9,900,000	
14	375.40	DIRECT - M & R STRUCTURES - REGULATING	DIRECT	1,000	0		1,000	
15	375.60	M & R STRUCTURES - DIST. IND. M & R	DIRECT	100,000	0		100,000	
16	375.70	M & R STRUCTURES - OTHER	11	10,000,000	360,803	4%	9,639,197	96%
17	375.71	M & R STRUCTURES - OTHER LEASED	11	10,000,000	360,803	4%	9,639,197	96%
18	375.80	M & R STRUCTURES - COMMUNICATION	DIRECT	10,000	0		10,000	
19	376.00	MAINS	DIRECT	1,000,000,000	50,000,000		950,000,000	
20	376.00	DIRECT - MAINS - MLDS	DIRECT	100,000	0		100,000	
21	376.08	MAINS-CSL REPLACEMENTS	DIRECT	10,000,000	0		10,000,000	
22	376.30	MAINS-BARE STEEL	DIRECT	10,000,000	0		10,000,000	
23	376.30	DIRECT - MAINS-BARE STEEL	DIRECT	100,000	0		100,000	
24	376.80	MAINS-CAST IRON	DIRECT	100,000	0		100,000	
25	378.10	M & R EQUIP - GENERAL	DIRECT	1,000,000	0		1,000,000	
26	378.20	M & R EQUIP - GENERAL - REGULATING	DIRECT	100,000,000	100,000		99,900,000	
27	378.20	DIRECT - M & R EQUIP-GEN-REG	DIRECT	1,000,000	0		1,000,000	
28	378.30	M & R EQUIP - LOCAL GAS PURCHASES	DIRECT	1,000,000	0		1,000,000	
29	379.10	M & R EQUIP - CITY GATE	DIRECT	100,000	0		100,000	
30	379.11	M & R EQUIP - EXCHANGE GAS	DIRECT	0	1,000		(1,000)	
31	380.00	SERVICES	DIRECT	100,000,000	10,000		99,990,000	
32	380.00	DIRECT - SERVICES	DIRECT	1,000	0		1,000	
33	380.12	CSL REPLACEMENT	DIRECT	0	0	0%	0	
34	381.00	METERS	16	100,000,000	909,008	1%	99,090,993	99%
35	381.00	DIRECT - METERS - MLDS FLEX	DIRECT	10,000	0		10,000	
36	381.10	AUTOMATIC METER READING	16	10,000,000	90,901	1%	9,909,099	99%
37	382.00	METER INSTALLATIONS	16	100,000,000	909,008	1%	99,090,993	99%
38	383.00	HOUSE REGULATORS	16	10,000,000	90,901	1%	9,909,099	99%
39	384.00	HOUSE REG INSTALLATIONS	16	1,000,000	9,090	1%	990,910	99%
40	385.00	IND M&R EQUIPMENT	DIRECT	10,000,000	1,000,000		9,000,000	
41	385.00	DIRECT - IND M&R EQUIPMENT	DIRECT	100,000	0		100,000	
42	385.10	IND M&R EQUIPMENT - LG VOLUME	DIRECT	1,000,000	0		1,000,000	
43	387.10	OTHER EQUIP DISTRIBUTION	11	10,000	361	4%	9,639	96%
44	387.20	OTHER EQUIP ODORIZATION	11	100,000	3,608	4%	96,392	96%
45	387.42	OTHER EQUIP RADIO	11	100,000	3,608	4%	96,392	96%
46	387.44	OTHER EQUIP COMMUNICATION	11	1,000,000	36,080	4%	963,920	96%
47	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	10,000,000	360,803	4%	9,639,197	96%
48	387.45	DIRECT - OTHER EQUIP CUSTOMER INFO SERVICE	DIRECT	0	0		0	
49	387.50	GPS EQUIPMENT	11	1,000,000	36,080	4%	963,920	96%
50		TOTAL DISTRIBUTION PLANT		1,510,053,010	54,483,153		1,455,569,857	
51	389-398	GENERAL PLANT	11	10,000,000	360,803	4%	9,639,197	96%
52		TOTAL GROSS PLANT		1,630,053,010	54,943,956		1,575,109,054	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEPRECIATION RESERVE
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

Exhibit NP-2
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ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY PEAK & AVERAGE			For Illustrative Purposes Only					
LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) \$	EDDS (E) \$	EDDS PERCENT (F)	JURISDICTIONAL (G) \$	JURISDICTIONAL PERCENT (H)
1	301-305	INTANGIBLE PLANT	DIRECT	10,000,000	100		9,999,900	
2	350-362	UNDERGROUND STORAGE PLANT	DIRECT	1,000,000	0		1,000,000	
		<u>DISTRIBUTION PLANT</u>						
3	374.10	LAND - CITY GATE & M/L IND M&R	DIRECT	0	0		0	
4	374.20	LAND - OTHER DISTRIBUTION	DIRECT	1,000,000	0		1,000,000	
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	DIRECT	0	0		0	
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	DIRECT	1,000,000	0		1,000,000	
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	DIRECT	0	0		0	
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	DIRECT	0	0		0	
9	374.50	RIGHTS OF WAY	DIRECT	1,000,000	100		999,900	
10	374.50	DIRECT - RIGHTS OF WAY	DIRECT	0	0		0	
11	375.20	M & R STRUCTURES - CITY GATE	DIRECT	0	0		0	
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	DIRECT	0	0		0	
13	375.40	M & R STRUCTURES - REGULATING	DIRECT	1,000,000	100		999,900	
14	375.40	DIRECT - M & R STRUCTURES - REGULATING	DIRECT	0	0		0	
15	375.60	M & R STRUCTURES - DIST. IND. M & R	DIRECT	10,000	0		10,000	
16	375.70	M & R STRUCTURES - OTHER	11	10,000,000	360,803	4%	9,639,197	96%
17	375.71	M & R STRUCTURES - OTHER LEASED	11	1,000,000	36,080	4%	963,920	96%
18	375.80	M & R STRUCTURES - COMMUNICATION	DIRECT	10,000	0		10,000	
19	376.00	MAINS	DIRECT	100,000,000	100,000		99,900,000	
20	376.00	DIRECT - MAINS - MLDS	DIRECT	0	0		0	
21	376.08	MAINS-CSL REPLACEMENTS	DIRECT	0	0		0	
22	376.30	MAINS-BARE STEEL	DIRECT	10,000,000	0		10,000,000	
23	376.30	DIRECT - MAINS-BARE STEEL	DIRECT	10,000	0		10,000	
24	376.80	MAINS-CAST IRON	DIRECT	0	0		0	
25	378.10	M & R EQUIP - GENERAL	DIRECT	0	0		0	
26	378.20	M & R EQUIP - GENERAL - REGULATING	DIRECT	10,000,000	100		9,999,900	
27	378.20	DIRECT - M & R EQUIP-GEN-REG	DIRECT	0	0		0	
28	378.30	M & R EQUIP - LOCAL GAS PURCHASES	DIRECT	0	0		0	
29	379.10	M & R EQUIP - CITY GATE	DIRECT	10,000	0		10,000	
30	379.11	M & R EQUIP - EXCHANGE GAS	DIRECT	0	0		0	
31	380.00	SERVICES	DIRECT	100,000,000	0		100,000,000	
32	380.00	DIRECT - SERVICES	DIRECT	0	0		0	
33	380.12	CSL REPLACEMENT	DIRECT	0	0		0	
34	381.00	METERS	16	10,000,000	90,901	1%	9,909,099	99%
35	381.00	DIRECT - METERS - MLDS FLEX	DIRECT	1,000	0		1,000	
36	381.10	AUTOMATIC METER READING	16	10,000,000	90,901	1%	9,909,099	99%
37	382.00	METER INSTALLATIONS	16	10,000,000	90,901	1%	9,909,099	99%
38	383.00	HOUSE REGULATORS	16	1,000,000	9,090	1%	990,910	99%
39	384.00	HOUSE REG INSTALLATIONS	16	1,000,000	9,090	1%	990,910	99%
40	385.00	IND M&R EQUIPMENT	DIRECT	1,000,000	10		999,990	
41	385.00	DIRECT - IND M&R EQUIPMENT	DIRECT	0	0		0	
42	385.10	IND M&R EQUIPMENT - LG VOLUME	DIRECT	0	0		0	
43	387.10	OTHER EQUIP DISTRIBUTION	11	0	0	4%	0	96%
44	387.20	OTHER EQUIP ODORIZATION	11	0	0	4%	0	96%
45	387.42	OTHER EQUIP RADIO	11	0	0	4%	0	96%
46	387.44	OTHER EQUIP COMMUNICATION	11	0	0	4%	0	96%
47	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	1,000,000	36,080	4%	963,920	96%
48	387.45	DIRECT - OTHER EQUIP CUSTOMER INFO SERVICE	DIRECT	10,000	0		10,000	
49	387.50	GPS EQUIPMENT	11	<u>1,000,000</u>	<u>36,080</u>	4%	<u>963,920</u>	96%
50		TOTAL DISTRIBUTION PLANT		270,051,000	860,236		269,190,764	
51	389-398	GENERAL PLANT	11	<u>10,000,000</u>	<u>360,803</u>	4%	<u>9,639,197</u>	96%
52		TOTAL DEPRECIATION RESERVE		<u>291,051,000</u>	<u>1,221,139</u>		<u>289,829,861</u>	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

Exhibit NP-2
Page 6 of 14

ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY
PEAK & AVERAGE

For Illustrative Purposes Only

LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) \$	EDDS (E) \$	EDDS PERCENT (F)	JURISDICTIONAL (G) \$	JURISDICTIONAL PERCENT (H)
1	301-305	INTANGIBLE PLANT	DIRECT	10,000,000	0		10,000,000	
2	350-362	UNDERGROUND STORAGE PLANT	DIRECT	100,000	0		100,000	
		<u>DISTRIBUTION PLANT</u>						
3	374.10	LAND - CITY GATE & M/L IND M&R	DIRECT	0	0		0	
4	374.20	LAND - OTHER DISTRIBUTION	DIRECT	0	0		0	
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	DIRECT	0	0		0	
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	DIRECT	100,000	0		100,000	
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	DIRECT	0	0		0	
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	DIRECT	0	0		0	
9	374.50	RIGHTS OF WAY	DIRECT	10,000	1		9,999	
10	374.50	DIRECT - RIGHTS OF WAY	DIRECT	0	0		0	
11	375.20	M & R STRUCTURES - CITY GATE	DIRECT	0	0		0	
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	DIRECT	0	0		0	
13	375.40	M & R STRUCTURES - REGULATING	DIRECT	100,000	1		99,999	
14	375.40	DIRECT - M & R STRUCTURES - REGULATING	DIRECT	0	0		0	
15	375.60	M & R STRUCTURES - DIST. IND. M & R	DIRECT	100	0		100	
16	375.70	M & R STRUCTURES - OTHER	11	1,000,000	36,080	4%	963,920	96%
17	375.71	M & R STRUCTURES - OTHER LEASED	11	1,000,000	36,080	4%	963,920	96%
18	375.80	M & R STRUCTURES - COMMUNICATION	DIRECT	100	0		100	
19	376.00	MAINS	DIRECT	10,000,000	10		9,999,990	
20	376.00	DIRECT - MAINS - MLDS	DIRECT	1,000,000	0		1,000,000	
21	376.08	MAINS-CSL REPLACEMENTS	DIRECT	0	0		0	
22	376.30	MAINS-BARE STEEL	DIRECT	1,000,000	0		1,000,000	
23	376.30	DIRECT - MAINS-BARE STEEL	DIRECT	0	0		0	
24	376.80	MAINS-CAST IRON	DIRECT	0	0		0	
25	378.10	M & R EQUIP - GENERAL	DIRECT	0	0		0	
26	378.20	M & R EQUIP - GENERAL - REGULATING	DIRECT	1,000,000	1		999,999	
27	378.20	DIRECT - M & R EQUIP-GEN-REG	DIRECT	1,000,000	0		1,000,000	
28	378.30	M & R EQUIP - LOCAL GAS PURCHASES	DIRECT	0	0		0	
29	379.10	M & R EQUIP - CITY GATE	DIRECT	1,000	0		1,000	
30	379.11	M & R EQUIP - EXCHANGE GAS	DIRECT	0	0		0	
31	380.00	SERVICES	DIRECT	10,000,000	0		10,000,000	
32	380.00	DIRECT - SERVICES	DIRECT	1,000,000	0		1,000,000	
33	380.12	CSL REPLACEMENT	DIRECT	0	0		0	
34	381.00	METERS	16	1,000,000	9,090	1%	990,910	99%
35	381.00	DIRECT - METERS - MLDS FLEX	DIRECT	100	0		100	
36	381.10	AUTOMATIC METER READING	16	100,000	909	1%	99,091	99%
37	382.00	METER INSTALLATIONS	16	1,000,000	9,090	1%	990,910	99%
38	383.00	HOUSE REGULATORS	16	100,000	909	1%	99,091	99%
39	384.00	HOUSE REG INSTALLATIONS	16	10,000	91	1%	9,909	99%
40	385.00	IND M&R EQUIPMENT	DIRECT	100,000	0		100,000	
41	385.00	DIRECT - IND M&R EQUIPMENT	DIRECT	1,000,000	0		1,000,000	
42	385.10	IND M&R EQUIPMENT - LG VOLUME	DIRECT	0	0		0	
43	387.10	OTHER EQUIP DISTRIBUTION	11	0	0	4%	0	96%
44	387.20	OTHER EQUIP ODORIZATION	11	0	0	4%	0	96%
45	387.42	OTHER EQUIP RADIO	11	0	0	4%	0	96%
46	387.44	OTHER EQUIP COMMUNICATION	11	0	0	4%	0	96%
47	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	100,000	3,608	4%	96,392	96%
48	387.45	DIRECT - OTHER EQUIP CUSTOMER INFO SER	DIRECT	1,000	0		1,000	
49	387.50	GPS EQUIPMENT	11	<u>10,000</u>	361	4%	<u>9,639</u>	96%
50		TOTAL DISTRIBUTION PLANT		30,632,300	96,231		30,536,069	
51								
52	389-398	GENERAL PLANT	11	<u>1,000,000</u>	36,080	4%	<u>963,920</u>	96%
53		NET DEPRECIATION & AMORTIZATION EXPENSE		41,732,300	132,312		41,599,988	
54		AMORTIZATION OF NET NEGATIVE SALVAGE	11	<u>1,000,000</u>	36,080	4%	<u>963,920</u>	96%
55		TOTAL AMORTIZATION AND DEPRECIATION EXPENSE		<u>42,732,300</u>	<u>168,392</u>		<u>42,563,908</u>	

COLUMBIA GAS OF PENNSYLVANIA, INC.
OPERATING REVENUE @ PROPOSED & CURRENT RATES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

Exhibit NP-2
Page 7 of 14

ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY
PEAK & AVERAGE

For Illustrative Purposes Only

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) \$	EDDS (E) \$	EDDS PERCENT (F)	JURISDICTIONAL (G) \$	JURISDICTIONAL PERCENT (H)
<u>PROPOSED OPERATING REVENUE</u>								
SALES REVENUE								
1	480/481	SALES BASE REVENUE	DIRECT	100,000,000	0		100,000,000	
2		USP REVENUE	DIRECT	10,000,000	0		10,000,000	
3		STAS REVENUE	DIRECT	0	0		0	
4		RIDER CC - CUSTOMER CHOICE	DIRECT	10,000	0		10,000	
5		RIDER EE - ENERGY EFFICIENCY	DIRECT	1,000,000	0		1,000,000	
6		GAS PROCUREMENT REVENUE	DIRECT	100,000	0		100,000	
7		MERCHANT FUNCTION REVENUE	DIRECT	1,000,000	0		1,000,000	
8		GAS COST REVENUE	DIRECT	<u>100,000,000</u>	<u>0</u>		<u>100,000,000</u>	
9		TOTAL SALES REVENUE		212,110,000	0		212,110,000	
TRANSPORTATION REVENUE								
10	489.00	TRANSPORTATION BASE REVENUE	DIRECT	105,000,000	5,000,000		100,000,000	
11		USP REVENUE	DIRECT	1,000,000	0		1,000,000	
12		STAS REVENUE	DIRECT	0	0		0	
13		RIDER CC - CUSTOMER CHOICE	DIRECT	1,000	0		1,000	
14		RIDER EE - ENERGY EFFICIENCY	DIRECT	100,000	0		100,000	
15		FLEX REVENUE	DIRECT	0	0		0	
16		GAS COST REVENUE	DIRECT	<u>1,000,000</u>	<u>0</u>		<u>1,000,000</u>	
17		TOTAL TRANSPORTATION REVENUE		107,101,000	5,000,000		102,101,000	
MISCELLANEOUS REVENUE								
18	487.00	FORFEITED DISCOUNTS	10	1,000,000	0	0%	1,000,000	100%
19	488.00	MISCELLANEOUS REVENUE	6	100,000	1	0%	99,999	100%
20	493.00	RENTS	11	0	0	4%	0	96%
21	495.00	OTHER	6	<u>1,000</u>	<u>0</u>	0%	<u>1,000</u>	100%
22		TOTAL MISCELLANEOUS REVENUE		1,101,000	1		1,100,999	
23		TOTAL PROPOSED OPERATING REVENUE		<u>320,312,000</u>	<u>5,000,001</u>		<u>315,311,999</u>	
<u>CURRENT OPERATING REVENUE</u>								
SALES REVENUE								
24	480/481	SALES BASE REVENUE	DIRECT	100,000,000	0		100,000,000	
25		USP REVENUE	DIRECT	10,000,000	0		10,000,000	
26		STAS REVENUE	DIRECT	0	0		0	
27		RIDER CC - CUSTOMER CHOICE	DIRECT	10,000	0		10,000	
28		RIDER EE - ENERGY EFFICIENCY	DIRECT	1,000,000	0		1,000,000	
29		GAS PROCUREMENT REVENUE	DIRECT	100,000	0		100,000	
30		MERCHANT FUNCTION REVENUE	DIRECT	1,000,000	0		1,000,000	
31		GAS COST REVENUE	DIRECT	<u>100,000,000</u>	<u>0</u>		<u>100,000,000</u>	
32		TOTAL SALES REVENUE		212,110,000	0		212,110,000	
TRANSPORTATION REVENUE								
33	489.00	TRANSPORTATION BASE REVENUE	DIRECT	105,000,000	5,000,000		100,000,000	
34		USP REVENUE	DIRECT	1,000,000	0		1,000,000	
35		STAS REVENUE	DIRECT	0	0		0	
36		RIDER CC - CUSTOMER CHOICE	DIRECT	1,000	0		1,000	
37		RIDER EE - ENERGY EFFICIENCY	DIRECT	100,000	0		100,000	
38		FLEX REVENUE	DIRECT	0	0		0	
39		GAS COST REVENUE	DIRECT	<u>1,000,000</u>	<u>0</u>		<u>1,000,000</u>	
40		TOTAL TRANSPORTATION REVENUE		107,101,000	5,000,000		102,101,000	
MISCELLANEOUS REVENUE								
41	487.00	FORFEITED DISCOUNTS	10	1,000,000	0	0%	1,000,000	0%
42	488.00	MISCELLANEOUS REVENUE	6	100,000	1	0%	99,999	100%
43	493.00	RENTS	11	0	0	4%	0	96%
44	495.00	OTHER	6	<u>1,000</u>	<u>0</u>	0%	<u>1,000</u>	100%
45		TOTAL MISCELLANEOUS REVENUE		1,101,000	1		1,100,999	
46		TOTAL CURRENT OPERATING REVENUE		<u>320,312,000</u>	<u>5,000,001</u>		<u>315,311,999</u>	

COLUMBIA GAS OF PENNSYLVANIA, INC.
PRODUCTION & DISTRIBUTION O&M EXPENSES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

Exhibit NP-2
Page 8 of 14

ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY
PEAK & AVERAGE

For Illustrative Purposes Only

LINE NO.	ACCT NO.	ACCOUNT TITLE	ALLOC FACTOR	TOTAL COMPANY	EDDS	EDDS PERCENT	JURISDICTIONAL	JURISDICTIONAL PERCENT
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)
				\$	\$		\$	
<u>PURCHASED GAS EXPENSES</u>								
1		GAS PURCHASED COST	DIRECT	100,000,000	0		100,000,000	
2	807.00	PURCHASED GAS EXPENSE	DIRECT	100,000	0		100,000	
3	807.00	GAS PROCUREMENT EXPENSE	DIRECT	<u>100,000</u>	<u>0</u>		<u>100,000</u>	
4		TOTAL PURCHASED GAS		<u>100,200,000</u>	<u>0</u>		<u>100,200,000</u>	
<u>UNDERGROUND STORAGE OPERATIONS EXPENSES</u>								
5	816.00	WELLS	DIRECT	0	0		0	
6	817.00	LINES	DIRECT	0	0		0	
7	818.00	COMPRESSOR STATION	DIRECT	0	0		0	
8	820.00	M & R	DIRECT	0	0		0	
9	821.00	PURIFICATION	DIRECT	0	0		0	
10	823.00	GAS LOSSES	DIRECT	100	0		100	
11	825.00	STORAGE WELL ROYALTIES	DIRECT	<u>1,000</u>	<u>0</u>		<u>1,000</u>	
12		TOTAL UNDERGROUND STORAGE OPERATIONS		1,100	0		1,100	
<u>UNDERGROUND STORAGE MAINTENANCE EXPENSES</u>								
13	832.00	WELLS	DIRECT	0	0		0	
14	834.00	COMPRESSOR STATION	DIRECT	0	0		0	
15	836.00	PURIFICATION	DIRECT	0	0		0	
16	841.00	OTHER STORAGE - OPS	DIRECT	<u>100</u>	<u>0</u>		<u>100</u>	
17		TOTAL UNDERGROUND STORAGE MAINTENANCE		100	0		100	
18		TOTAL UNDERGROUND STORAGE		<u>1,200</u>	<u>0</u>		<u>1,200</u>	
<u>DISTRIBUTION OPERATIONS EXPENSES</u>								
19	870.00	SUPERVISION & ENGINEERING	18	1,000,000	41,788	4%	958,212	96%
20	871.00	LOAD DISPATCHING	13	100,000	4,901	5%	95,099	95%
21	874.00	MAINS & SERVICES	14	10,000,000	446,007	4%	9,553,993	96%
22	875.00	M & R - GENERAL	13	100,000	4,901	5%	95,099	95%
23	876.00	M & R - INDUSTRIAL	17	100,000	9,009	9%	90,991	91%
24	878.00	METERS & HOUSE REGULATORS	23	1,000,000	9,090	1%	990,910	99%
25	879.00	CUSTOMER INSTALLATIONS	15	1,000,000	100	0%	999,900	100%
26	880.00	OTHER	18	1,000,000	41,788	4%	958,212	96%
27	881.00	RENTS	18	<u>0</u>	<u>0</u>	4%	<u>0</u>	96%
28		TOTAL DISTRIBUTION OPERATIONS		14,300,000	557,583		13,742,417	
<u>DISTRIBUTION MAINTENANCE EXPENSES</u>								
29	885.00	SUPERVISION & ENGINEERING	18	100,000	4,179		95,821	
30	886.00	STRUCTURES AND IMPROVEMENTS	13	100,000	4,901	5%	95,099	95%
31	887.00	MAINS	13	10,000,000	490,052	5%	9,509,948	95%
32	889.00	M & R - GENERAL	13	1,000,000	49,005	5%	950,995	95%
33	890.00	M & R - INDUSTRIAL	17	100,000	9,009	9%	90,991	91%
34	892.00	SERVICES	15	1,000,000	100	0%	999,900	100%
35	893.00	METERS & HOUSE REGULATORS	23	100,000	909	1%	99,091	99%
36	894.00	OTHER EQUIPMENT	18	<u>100,000</u>	4,179	4%	<u>95,821</u>	96%
37		TOTAL DISTRIBUTION MAINTENANCE		12,500,000	562,333		11,937,667	
38		TOTAL DISTRIBUTION		<u>26,800,000</u>	<u>1,119,916</u>		<u>25,680,084</u>	

**COLUMBIA GAS OF PENNSYLVANIA, INC.
OTHER O&M EXPENSES**

FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

**Exhibit NP-2
Page 9 of 14**

**ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY
PEAK & AVERAGE**

For Illustrative Purposes Only

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) \$	EDDS (E) \$	EDDS PERCENT (F)	JURISDICTIONAL (G) \$	JURISDICTIONAL PERCENT (H)
<u>CUSTOMER ACCOUNTS EXPENSES</u>								
1	901.00	SUPERVISION	6	0	0	0%	0	100%
2	902.00	METER READING	6	100,000	1	0%	99,999	100%
3	903.00	CUSTOMER RECORDS AND COLLECTION EXPENSES	6	1,000,000	10	0%	999,990	100%
4	903.00	INTEREST ON CUSTOMER DEPOSITS	9	100,000	0	0%	100,000	100%
5	904.00	UNCOLLECTIBLES-DIS REVENUE	7	1,000,000	0	0%	1,000,000	100%
6	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	8	100,000	0	0%	100,000	100%
7	904.00	UNCOLLECTIBLES-UNBUNDLED GAS	Direct	1,000,000	0		1,000,000	
8	904.00	DIRECT USP UNCOLLECTIBLES	Direct	10,000,000	0		10,000,000	
9	904.00	UNCOLLECTIBLES-DIS COVID-19 DEFERRAL	7	100,000	0	0%	100,000	100%
10	904.00	UNCOLLECTIBLES-GMB/GTS COVID-19 DEFERRAL	8	10,000	0	0%	10,000	100%
11	905.00	MISCELLANEOUS	6	0	0	0%	0	100%
12	921.00	OFFICE SUPPLIES & EXPENSES	6	0	0	0%	0	100%
13		TOTAL CUSTOMER ACCOUNTS		<u>13,410,000</u>	<u>11</u>		<u>13,409,989</u>	
<u>CUST SERVICE & INFORMATION EXPENSES</u>								
14	907.00	SUPERVISION	6	0	0	0%	0	100%
15	908.00	CUSTOMER ASSISTANCE	6	100	0	0%	100	100%
16	909.00	INFORMATIONAL & INSTRUCTIONAL EXPENSES	6	0	0	0%	0	100%
17	910.00	MISCELLANEOUS	6	1,000,000	10	0%	999,990	100%
18	921.00	OFFICE SUPPLIES & EXPENSES	6	0	0	0%	0	100%
19	931.00	RENTS - GENERAL	6	0	0	0%	0	100%
20	932.00	MAINTENANCE	6	0	0	0%	0	100%
21		TOTAL CUST SERVICE & INFORMATION		<u>1,000,100</u>	<u>10</u>		<u>1,000,090</u>	
<u>SALES EXPENSES</u>								
22	912.00	DEMONSTRATION	6	1,000	0	0%	1,000	100%
23	913.00	ADVERTISING	6	0	0	0%	0	100%
24		TOTAL SALES		<u>1,000</u>	<u>0</u>		<u>1,000</u>	
<u>ADMINISTRATIVE AND GENERAL EXPENSES</u>								
25	920.00	SALARIES	19	10,000,000	417,879	4%	9,582,121	96%
26	921.00	OFFICE SUPPLIES & EXPENSES	19	1,000,000	41,788	4%	958,212	96%
27	922.00	ADMIN. EXPENSE TRANSFERRED	19	0	0	4%	0	96%
28	923.00	OUTSIDE SERVICES EMPLOYED	19	10,000,000	417,879	4%	9,582,121	96%
29	924.00	PROPERTY INSURANCE	19	100,000	4,179	4%	95,821	96%
30	925.00	INJURIES AND DAMAGES	19	1,000,000	41,788	4%	958,212	96%
31	926.00	EMPLOYEE PENSIONS & BENEFITS	24	10,000,000	99,010	1%	9,900,990	99%
32	928.00	REGULATORY COMMISSION EXPENSES	19	1,000,000	41,788	4%	958,212	96%
33	930.00	MISCELLANEOUS GENERAL	19	1,000,000	41,788	4%	958,212	96%
34	931.00	RENTS-GENERAL	19	1,000,000	41,788	4%	958,212	96%
35	932.00	MAINTENANCE	19	1,000,000	41,788	4%	958,212	96%
36		TOTAL ADMINISTRATIVE & GENERAL		<u>36,100,000</u>	<u>1,189,674</u>		<u>34,910,326</u>	
37		TOTAL O & M EXPENSES		<u>177,512,300</u>	<u>2,309,611</u>		<u>175,202,689</u>	

COLUMBIA GAS OF PENNSYLVANIA, INC.
TAXES OTHER THAN INCOME TAXES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

Exhibit NP-2
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ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY
PEAK & AVERAGE

For Illustrative Purposes Only

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D)	EDDS (E)	EDDS PERCENT (F)	JURISDICTIONAL (G)	JURISDICTIONAL PERCENT (H)
		<u>FEDERAL TAXES</u>		\$	\$		\$	
1	408.00	FEDERAL/STATE UNEMPLOYMENT	24	10,000	99	1%	9,901	99%
2	408.00	FICA	24	<u>1,000,000</u>	<u>9,901</u>	1%	<u>990,099</u>	99%
3		TOTAL FEDERAL TAXES		<u>1,010,000</u>	<u>10,000</u>		<u>1,000,000</u>	
		<u>STATE TAXES</u>						
4	408.00	PA PROPERTY TAXES	11	1,000,000	36,080	4%	963,920	96%
5	408.00	PA STATE UNEMPLOYMENT	24	0	0	1%	0	99%
6	408.00	STATE CAPITAL STOCK TAX	11	0	0	4%	0	96%
7	408.00	LICENSE AND FRANCHISE TAX	11	0	0	4%	0	96%
8	408.00	STATE SALES AND USE TAX	19	100,000	4,179	4%	95,821	96%
9	408.00	OTHER	19	<u>1,000</u>	<u>42</u>	4%	<u>958</u>	96%
10		TOTAL STATE TAXES		<u>1,101,000</u>	<u>40,301</u>		<u>1,060,699</u>	
11		TOTAL TAXES OTHER THAN INCOME		<u>2,111,000</u>	<u>50,301</u>		<u>2,060,699</u>	

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE BASE
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

Exhibit NP-2
Page 11 of 14

ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY
PEAK & AVERAGE

For Illustrative Purposes Only

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) \$	EDDS (E) \$	EDDS PERCENT (F)	JURISDICTIONAL (G) \$	JURISDICTIONAL PERCENT (H)
1	101-107	GROSS PLANT [PAGE 3]		1,630,053,010	54,943,956		1,575,109,054	
2	117.00	GAS STORED UNDERGROUND - NON CURRENT	DIRECT	1,000	0		1,000	
3	108-111	DEPRECIATION RESERVE [PAGE 4]		(291,051,000)	(1,221,139)		(289,829,861)	
4	117.00	GAS LOST-UNDERGROUND STORAGE	DIRECT	0	0		0	
5		NET PLANT		1,339,003,010	53,722,817		1,285,280,194	
<u>WORKING CAPITAL</u>								
6	154.00	MATERIALS & SUPPLIES	11	100,000	3,608	4%	96,392	96%
7	164.00	GAS STORED UNDERGROUND - FSS	DIRECT	10,000,000	0		10,000,000	
8	165.00	PREPAYMENTS	19	1,000,000	41,788	4%	958,212	96%
9	165.00	CLOUD BASED ASSETS	11	0	0	4%	0	96%
10		CASH WORKING CAPITAL - GAS PURCHASES	4	0	0	0%	0	100%
11		CASH WORKING CAPITAL - ALL OTHER	19	0	0	4%	0	96%
12		TOTAL WORKING CAPITAL		11,100,000	45,396		11,054,604	
<u>DEFERRED INCOME TAXES</u>								
13	190.00	ACCUMULATED DEF INCOME TAX	12	10,000,000	337,069	3%	9,662,931	97%
14	282.00	ACCUMULATED DEF INCOME TAX	12	(100,000,000)	(3,370,685)	3%	(96,629,315)	97%
15	283.00	ACCUMULATED DEF INCOME TAX	12	0	0	3%	0	97%
16	254.00	EXCESS ADIT	12	(100,000,000)	(3,370,685)	3%	(96,629,315)	97%
17	182.00	REG ASSET DEFICIENT ADIT (BEFORE GROSS UP)	12	<u>1,000,000</u>	<u>33,707</u>	3%	<u>966,293</u>	97%
18		TOTAL DEFERRED INCOME TAXES		(189,000,000)	(6,370,595)		(182,629,405)	
19	235.00	CUSTOMER DEPOSITS	9	(1,000,000)	0	0%	(1,000,000)	100%
20	252.00	CUSTOMER ADVANCES	5	<u>1,000</u>	<u>0</u>	0%	<u>1,000</u>	100%
21		RATE BASE		<u>1,160,104,010</u>	<u>47,397,617</u>		<u>1,112,706,393</u>	

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATE/FEDERAL INCOME TAXES
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

Exhibit NP-2
Page 12 of 14

ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY
PEAK & AVERAGE

For Illustrative Purposes Only

LINE NO.	ACCT NO. (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) \$	EDDS (D) \$	EDDS PERCENT (E)	JURISDICTIONAL (F) \$	JURISDICTIONAL PERCENT (G)
<u>STATE INCOME TAX</u>							
1	OPERATING INCOME BEFORE TAXES (PG. 2, LINE 7)		97,956,400	2,471,697		95,484,703	
2	STATUTORY ADJUSTMENTS	12	10,000,000	337,069	3%	9,662,931	97%
3	INTEREST ON DEBT		(26,914,413)	(1,099,625)		(25,814,788)	
4	PA BONUS DEPRECIATION ADJUSTMENT	12	<u>10,000,000</u>	<u>337,069</u>	3%	<u>9,662,931</u>	97%
5	STATE TAXABLE INCOME		91,041,987	2,046,209		88,995,778	
6	NET OPERATING LOSS DEDUCTION	12	<u>0</u>	<u>0</u>	3%	<u>0</u>	97%
	STATE TAXABLE INCOME		91,041,987	2,046,209		88,995,778	
7	STATE NET INCOME TAX @ 7.99%		7,274,255	163,492		7,110,763	
8	DEFERRED INCOME TAXES	12	<u>0</u>	<u>0</u>	3%	<u>0</u>	97%
9	STATE INCOME TAX		7,274,255	163,492		7,110,763	
<u>FEDERAL INCOME TAX</u>							
10	OPERATING INCOME BEFORE TAXES (PG. 2, LINE 7)		97,956,400	2,471,697		95,484,703	
11	STATE NET INCOME TAX (LINE 9)		(7,274,255)	(163,492)		(7,110,763)	
12	STATUTORY ADJUSTMENTS (LINES 2 & 3)	12	<u>(16,914,413)</u>	<u>(570,132)</u>	3%	<u>(16,344,281)</u>	97%
13	FEDERAL TAXABLE INCOME		73,767,732	1,738,073		72,029,659	
14	FEDERAL INCOME TAX @ 21%		15,491,224	364,995		15,126,228	
15	DEFERRED INCOME TAXES	12	10,000,000	337,069	3%	9,662,931	97%
16	TAX REFUND AMORTIZATION	12	0	0	3%	0	97%
17	FLOW BACK OF EXCESS DEFERRED TAXES	12	(1,000,000)	(33,707)	3%	(966,293)	97%
18	EFFECT OF CNIT DEFERRED TAX ON FIT	12	<u>0</u>	<u>0</u>	3%	<u>0</u>	97%
19	FEDERAL INCOME TAX		24,491,224	668,357		23,822,867	
20	STATE NET INCOME TAX (LINE 9)		<u>7,274,255</u>	<u>163,492</u>		<u>7,110,763</u>	
21	TOTAL INCOME TAXES		<u>31,765,479</u>	<u>831,849</u>		<u>30,933,629</u>	

COLUMBIA GAS OF PENNSYLVANIA, INC.
ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

Exhibit NP-2
Page 13 of 14

ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY
PEAK & AVERAGE

For Illustrative Purposes Only

LINE NO.	DESCRIPTION (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	EDDS (D)	JURISDICTIONAL (E)
1	DESIGN DAY	1	100,000	0	100,000
2	PERCENT		100%	0%	100%
3	THROUGHPUT EXCLUDING TRANSPORTATION	2	10,000,000	0	10,000,000
4	PERCENT		100%	0%	100%
5	THROUGHPUT EXCLUDING MLDS	3	10,000,000	0	10,000,000
6	PERCENT		100%	0%	100%
7	GAS PURCHASED EXPENSE	4	100,000,000	0	100,000,000
8	PERCENT		100%	0%	100%
9	PEAK & AVERAGE MAINS	5			
10	PERCENT		100%	0%	100%
11	AVERAGE NO. OF CUSTOMERS	6	100,001	1	100,000
12	PERCENT		100%	0%	100%
13	DISTRIBUTION UNCOLLECTIBLES	7	10,000,000	0	10,000,000
14	PERCENT		100%	0%	100%
15	CURRENT GMB/GTS REVENUE	8	1,000,000	0	1,000,000
16	PERCENT		100%	0%	100%
17	CUSTOMER DEPOSITS	9	1,000,000	0	1,000,000
18	PERCENT		100%	0%	100%
19	FORFEITED DISCOUNTS	10	100,000	0	100,000
20	PERCENT		100%	0%	100%
21	DIST. PLANT EXCL ACCTS 375.70, 375.71, & 387	11	1,477,843,010	53,321,007	1,424,522,003
22	PERCENT		100%	4%	96%
23	GROSS PLANT	12	1,630,053,010	54,943,956	1,575,109,054
24	PERCENT		100%	3%	97%
25	MAINS - ACCOUNT 376	13	1,020,300,000	50,000,000	970,300,000
26	PERCENT		100%	5%	95%

COLUMBIA GAS OF PENNSYLVANIA, INC.
 ALLOCATION FACTORS (CONT.)
 FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2026

Exhibit NP-2
 Page 14 of 14

ALLOCATED COST OF SERVICE - JURISDICTIONAL STUDY
 PEAK & AVERAGE

For Illustrative Purposes Only

LINE NO.	DESCRIPTION (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	EDDS (D)	JURISDICTIONAL (E)
27	COMPOSITE DIRECT PLANT - ACCTS 376 & 380	14	1,123,300,000	50,100,000	1,073,200,000
28	PERCENT		100%	4%	96%
29	SERVICES	15	100,001,000	10,000	99,991,000
30	PERCENT		100%	0%	100%
31	METERS	16	110,010,092	1,000,000	109,010,092
32	PERCENT		100%	1%	99%
33	INDUSTRIAL M & R	17	11,100,000	1,000,000	10,100,000
34	PERCENT		100%	9%	91%
35	OTHER DISTRIBUTION O & M EXPENSES	18	26,800,000	1,119,916	25,680,084
36	PERCENT		100%	4%	96%
37	O & M EXCL GAS PUR, UNCOLLECTIBLES, & A & G	19	26,800,000	1,119,916	25,680,084
38	PERCENT		100%	4%	96%
39	CUSTOMER/DEMAND MAINS	20			
40	PERCENT		100%	0%	100%
41	HOUSE REGULATORS (GPA 383)	21	10,000,000	90,901	9,909,099
42	PERCENT		100%	1%	99%
43	AVERAGE - ALLOCATORS 5 & 20	22			
44	PERCENT		100%	0%	100%
45	METERS	23	221,010,000	2,008,907	219,001,093
46	PERCENT		100%	1%	99%
47	LABOR	24	10,100,000	100,000	10,000,000
48	PERCENT		100%	1%	99%
49	SALES AND CHOICE TRANSPORTATION	25	319,211,000	5,000,000	314,211,000
50	PERCENT		100%	2%	98%

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

DIRECT TESTIMONY OF
JENNIFER HARDING
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

Q. Please state your name and business address.

A. My name is Jennifer Harding. My business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

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

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is VP Tax at NCSC.

Q. What are your responsibilities as VP Tax?

A. In my current position as VP Tax, I am responsible for all tax matters for NiSource and its subsidiaries, including Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"). My responsibilities include oversight of the income and indirect tax accounting and reporting, forecasting income and indirect taxes, preparation and filing income and indirect tax returns, technical income tax research, tax planning, income and indirect tax audits and review and implementation of federal and state tax legislation.

Q. What is your educational and professional background?

A. I earned a B.A. in Business Administration with a concentration in Accounting in 2007 from the Notre Dame of Maryland University in Baltimore, Maryland. I began my career with KPMG in Baltimore, Maryland in 2005. In 2009, I joined Constellation Energy as a Tax Manager responsible for all aspects of income tax and non-income tax for the generation segment and managed the IRS Federal tax audit Compliance Assurance Process program. Constellation was acquired by Exelon Corporation in 2012, and I served as the Tax Manager of the regulated

1 electric utility in Chicago, Illinois, responsible for income tax accounting,
2 forecasting income taxes, and income tax and non-income tax return filings. In
3 2014, I worked as the Tax Manager for Mead Johnson Nutrition BV for the
4 European region with responsibility for all aspects of income tax and non-income
5 tax accounting, tax research and tax return filings. In 2016, I worked for Cardinal
6 Health in Columbus, Ohio, as the Director of International Tax Operations with
7 responsibility for income tax accounting, forecasting, mergers & acquisitions, tax
8 research, and tax return filings in Cardinal Health's foreign jurisdictions. In 2018,
9 I worked as the Head of Tax for Hyperion Materials & Technologies with full
10 responsibility for all global income and non-income tax accounting, tax return
11 filings, research, mergers & acquisitions, and forecasting. In January 2020, I
12 joined NiSource as the Director of Income Tax Operations and was promoted to
13 VP Tax in February 2023.

14 **Q. Have you previously testified before this or any other regulatory**
15 **commission?**

16 A. Yes, I previously testified before the Pennsylvania Public Utility Commission
17 ("Commission") in Columbia's base rate cases at Docket Nos. R-2022-3031211 and
18 R-2024-3046519. I have also previously testified in proceedings before the Indiana
19 Utility Regulatory Commission, the Kentucky Public Service Commission, the
20 Maryland Public Service Commission, the Public Utilities Commission of Ohio,
21 and the Virginia State Corporation Commission.

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

23 A. The primary purpose of my testimony is to present and support Columbia's income

1 tax and other tax expense included in the cost of service. The filing includes federal
2 and state income tax recovery, reduction of rate base for deferred income taxes and
3 incorporation of the effects of the enacted Tax Cuts and Jobs Act of 2017 (“TCJA”).
4 The income tax calculations are included in Exhibit 7 for the Historic Test Year (the
5 twelve-month period ending November 30, 2024) and Exhibit 107 for the Future
6 Test Year (the twelve-month period ending November 30, 2025) and Fully
7 Projected Future Test Year (the twelve-month period ending December 31, 2026).
8 Taxes other than income tax are included in Exhibit 6 for the Historic Test Year
9 and Exhibit 106 for the Future Test Year and Fully Projected Future Test Year.

10 **Q. Will you explain the basis for the income tax calculations for the Historic**
11 **Test Year?**

12 A. The tax calculations were made in accordance with federal and state laws. The
13 federal tax rate in effect for the Historic Test Year is 21%. The federal tax rate of 21%
14 has also been reflected for the Future Test Year and the Fully Projected Future Test
15 Year. The Historic Test Year tax calculations have been impacted by certain items
16 that have been historically treated as flow-through or deferred in rate making
17 proceedings.

18 **Q. Has the Company recognized the reduction of the Pennsylvania**
19 **corporate net income tax rate in the state income tax expense?**

20 A. Yes, H.B. 1342 was signed into law on July 8, 2022. The legislation decreases the
21 corporate income tax rate from 8.99% in 2023 to 8.49% in 2024, 7.99% in 2025 and
22 7.49% in 2026.

23 **Q. Can you explain the deficient accumulated deferred income taxes**

recognized and flow-through items included in the tax provision and impacts of Pennsylvania H.B. 1342?

A. Yes, the Company also has non-property related deferred taxes on customer advances and inventory that have been normalized in rate base for federal and state purposes. The Company remeasured the accumulated deferred state taxes from 9.99% over the 9-year reduction to 4.99% in 2031 and recognized the deficient deferred tax of \$1,782,085 (before gross-up) recorded to a regulatory asset. The Company proposes to recognize the flow-through impact to tax expense over a ten-year amortization in the Fully Projected Future Test Year, which represents deficient deferred tax expense of \$178,209 per year (See Exhibit 107, Page 16, Column 4, Line 31 for the flow back of net Excess Deferred Taxes of (\$2,676,400), which represents this amount, plus TJCA excess deferred taxes for plant/property of (\$3,874,755) and deficient deferred taxes for the Federal Net Operating Loss ("NOL") of \$571,394 and inventory/customer advances of \$626,961 discussed below).

Q. Can you explain the flow-through items included in the tax provision and impacts of the TCJA?

A. Yes. Prior to 1981, federal tax statutes did not require full normalization of accelerated tax depreciation versus book straight line depreciation recovered in rates. Beginning in 1981, the normalization method of accounting prevented utilities from recognizing a reduction in current taxes resulting from the application of accelerated tax depreciation to be immediately recognized as flow-through to utility ratepayers under the Internal Revenue Code. Instead, such benefits must be provided for in a deferred tax reserve, and that reserve may be allowed as a rate base

1 reduction. Prior to 1984, the Company flowed-through the benefits of accelerated
2 depreciation for vintage years prior to 1981. Beginning in 1984, the Company began
3 to normalize the remaining book versus tax differences on Asset Depreciation Range
4 vintages (1971 through 1980) based upon the Commission's order in Docket No. R-
5 832493. For the Historic Test Year, the Company has very little in terms of tax
6 depreciation remaining on pre-1981 assets. Thus, Columbia is in a turnaround
7 position, since book depreciation is now higher than tax depreciation. In addition,
8 the Company has excess accumulated deferred income taxes that were originally
9 computed at higher federal tax rates (namely 46% federal tax rate for asset vintages
10 1981-1987 and 35% federal tax rate for asset vintages 1988-2017) compared to the
11 current corporate income tax rate of 21%, a result of the enactment of TCJA, that are
12 being refunded in rates under the Average Rate Assumption Method ("ARAM").
13 ARAM is the method under which the excess in the reserve for deferred income taxes
14 is reduced over the remaining lives of the property as used in its books of account
15 that gave rise to the reserve for deferred income taxes and flow-through the
16 amortization of the excess accumulated deferred income taxes. Because most of the
17 book versus tax differences related to assets that were 15- or 20-year property for
18 federal tax purposes and there were multiple years of bonus depreciation since 2001,
19 the excess is in a turnaround situation. There is a variable nature inherent in ARAM,
20 which does not result in an amount that is fixed in every period due to factors such
21 as changes in capital additions, depreciation rates, future retirements, and the
22 vintages of those retirements. The Company projects to record lower tax expense of
23 \$3,874,755 in its federal tax provision related to the excess accumulated deferred

1 income taxes on asset vintages 1981-2017 for the Fully Projected Future Test Year.

2 **Q. Are there any other deferred taxes that are impacted by the TCJA?**

3 A. Yes, the Company also has deferred taxes for the Federal NOL, customer advances,
4 inventory, and other book versus tax timing differences. The federal rate reduction
5 creates net deficient deferred taxes that were originally computed at a 35% federal
6 tax rate for these assets that are reversing to a 21% federal tax rate. For the Federal
7 NOL, the Company includes the recovery of the deficient deferred taxes over the
8 estimated remaining life of the assets of 42 years based on a composite book
9 depreciation rate of 2.4% as included in the last base rate case and projects to record
10 higher tax expense in the amount of \$571,394 for the Fully Projected Future Test
11 Year. For the non-property related deferred taxes on customer advances and
12 inventory that are included in the calculation of rate base, the Company projects to
13 record higher tax expense in its federal tax provision by \$626,961, using a ten-year
14 amortization period for the Fully Projected Future Test Year. The remaining non-
15 property deferred taxes on book versus tax timing differences are a net deferred tax
16 asset which results in net deficient deferred taxes because of TCJA. It is the
17 Company's position that because those deferred taxes were not included in the
18 calculation of rate base, the Company is not seeking recovery of the deficient
19 deferred taxes resulting from the decrease in the federal income tax rate.

20 **Q. Does the Company intend to recognize a change in accounting method to**
21 **adopt the natural gas safe harbor ("NGSH") method issued under**
22 **Revenue Procedure 2023-15 consistent with the 2008 change in method**
23 **of accounting for repairs impact Columbia's taxable income in the rate-**

1 **making process?**

2 A. Yes, in response to taxpayer feedback that the “preference” period for early adoption
3 did not provide taxpayers with adequate time to make the changes, the IRS extended
4 the favorable rules to Year 2 adoption period in Revenue Procedure 2024-23. Given
5 this extension of time, NiSource expects to elect the change in tax accounting method
6 on our 2024 consolidated tax return filing due on or before the extended due date of
7 October 15, 2025. The Company is in the process of reviewing and quantifying the
8 provisions of the safe harbor method for taxpayers with natural gas transmission
9 and distribution property. The federal repairs deduction will be normalized under
10 deferred tax accounting, so there will be no impact on total federal tax expense.
11 However, the repairs deduction has not been normalized for state income tax
12 purposes, based on prior Commission orders, and is expected to be recognized as
13 flow-through for state tax purposes and is reflected in the state tax expense. Since
14 Columbia recognized a method change in 2008 to deduct qualified costs as
15 deductible repairs, the Company does not expect material impact in adopting the
16 NGSM method.

17 **Q. Are there any other items treated as flow-through in the rate-making**
18 **process?**

19 A. Yes. The Company continues to reduce its income tax allowance for the net cost of
20 retirements, which is allowed as a deduction on its tax return. In addition, there are
21 three permanent differences included in the tax provision. A permanent difference
22 results when revenue (gain) or expense (loss) is recognized in book accounting but
23 not recognized under the rules of the Internal Revenue Code, or vice versa.

1 Permanent items increasing tax expense are non-deductible expenses for business
2 meals and employee stock purchase plan compensation included in the total flow-
3 through adjustments on Exhibit 107, Page 16, Line 12.

4 **Q. How has the Company handled Pennsylvania Corporate Net Income**
5 **Taxes in its calculation of deferred income taxes for property?**

6 A. The Company, based on prior Commission orders, has not normalized deferred state
7 income taxes. The Company continues to flow-through the state income tax benefits
8 of accelerated depreciation on its book depreciable assets. The Company was not
9 permitted to claim the benefit of Federal bonus depreciation deductions that have
10 been taken in years prior to 2018 in the Pennsylvania corporate tax and recognizes
11 a state modification for accelerated tax deductions in future years for previously-
12 disallowed bonus depreciation.

13 **Q. Does the Company fully utilize the Pennsylvania NOL carryforward in**
14 **the Historic Test Year?**

15 A. Yes. The Company had a \$144,975,996 NOL for 2008 that was carried forward to
16 future years. In October 2017, the Pennsylvania Supreme Court held that the flat-
17 dollar cap on the NOL deduction violated the Uniformity Clause of the Pennsylvania
18 Constitution¹ thereby affirming the Commonwealth Court of Pennsylvania decision
19 in 2015². The Pennsylvania Supreme Court ordered that the flat-dollar cap of \$5
20 million be removed. In anticipation of the Pennsylvania Supreme Court ruling, the
21 Pennsylvania House of Representatives passed H.B. 542, which included a provision

¹ *Nextel Communications of the Mid-Atlantic, Inc. v. Commonwealth*, 171 A.3d 682 (Pa. 2017).

² *Nextel Communications of the Mid-Atlantic, Inc., v. Commonwealth*, 129 A.3d 1 (Pa. Commw. 2015).

1 that removed the \$5 million cap on NOL deductions and increased the then-current
2 cap of 30% of taxable income to 35% for tax year 2018 and 40% for tax year 2019
3 and future years. On October 30, 2017, Pennsylvania Governor Tom Wolf signed
4 H.B. 542 into law. In response to the decision, the Pennsylvania Department of
5 Revenue revised its forms and procedures to eliminate the \$5 million flat-dollar cap.
6 The Company's computed state tax expense considers the NOL limitation of 40% of
7 state taxable income in the Historic Test Year and Future Test Year. However, the
8 remaining Pennsylvania NOL is less than 40% of state taxable income in the Historic
9 Test Year (Exhibit 7, Page 20, Line 6). The Pennsylvania NOL carryforward is
10 reflected on Exhibit 7, Page 23 depicting the Pennsylvania NOL carryforward is fully
11 utilized in the Historic Test Year.

12 **Q. Does the utilization of the Pennsylvania NOL carryforward impact the**
13 **revenue gross-up factor computed on Exhibit 102, Schedule 3 for the**
14 **Fully Projected Future Test Year ending December 31, 2026?**

15 A. No, the benefit of the Pennsylvania NOL has been fully utilized in the Historic Test
16 Year. Consequently, the revenue gross up factor presented on Exhibit 102, Schedule
17 3, Page 5, Line 12 includes the Pennsylvania state income tax rate of 7.49% for the
18 year ending December 31, 2026.

19 **Q. Does the Company's proposed revenue requirement reflect a**
20 **consolidated tax adjustment?**

21 A. No. The passage of Act 40, 66 Pa. C.S. § 1301.1, which became effective August 10,
22 2016, eliminated the consolidated tax adjustment in ratemaking. Title 66 of the
23 Pennsylvania Consolidated Statutes Section 1301.1 states that for the computation of

1 income tax expense for ratemaking purposes, if an expense or investment is not
2 allowed to be included in a public utility's rates, the tax losses of a public utility's
3 parent or affiliated companies should not be included in computation of income tax
4 expense to reduce rates. However, Section 1301.1(b) requires a public utility seeking
5 to change rates to demonstrate that it shall use at least 50 percent of what would
6 have been a consolidated tax expense adjustment under the law prior to Act 40 for
7 reliability or infrastructure related capital investment and the other 50 percent shall
8 be used for general corporate purposes. The Company prepared Exhibit No. 7, Pages
9 2 through 4 for the computation of the Section 1301.1 differential and details of the
10 income and losses of affiliated companies for the periods 2021 to 2023. The
11 Company computed what the consolidated tax expense adjustment would have been
12 by dividing the 3-year average of Columbia's Federal taxable income of \$83.1 million
13 by the 3-year average of the Federal taxable income of the consolidated group
14 members with taxable income of \$469.8 million to determine the percentage of
15 Columbia's income of 18%. This percentage was multiplied by the 3-year average of
16 Federal taxable loss of the adjusted consolidated group members with taxable loss
17 of \$121.9 million. Columbia's allocation of Federal taxable loss companies is \$21.6
18 million tax effected at 21% resulting in a Section 1301.1(b) differential of \$4.53
19 million.

20 **Q. Does the Company's rate case claim support the conclusion that it is**
21 **using at least 50 percent of the amount that would have been a**
22 **consolidated tax adjustment prior to Act 40 to support reliability or**
23 **infrastructure related capital investment?**

1 A. Yes, as depicted in GAS-RR-014, Attachment A and discussed in the direct testimony
2 of Columbia witness Julie Covert (Columbia St. No. 11), Columbia's pro forma capital
3 additions for reliability or infrastructure projects (Replacement Age & Condition)
4 are \$316.8 million in the Future Test Year and \$329.3 million in the Fully Projected
5 Future Test Year. This expenditure level is greater than \$2.26 million (50% of the
6 \$4.53 million Section 13.01.1(b) differential) that would have been a consolidated
7 tax adjustment prior to Act 40 of 2016.

8 **Q. Does the Company's rate case claim support the conclusion that it is**
9 **using at least 50 percent the amount that would have been a consolidated**
10 **tax adjustment prior to Act 40 to support the amount of the revenue**
11 **requirement attributed to general corporate purposes?**

12 A. Yes, as depicted in Exhibit 102, Schedule 3, Page 3, Line 18 and discussed in direct
13 testimony of Columbia witness Joseph Vassalotti (Columbia St. No. 4), Columbia's
14 pro forma operating and maintenance budget is \$227.1 million in the Future Test
15 Year and \$223.6 million in the Fully Projected Future Test Year. This expenditure
16 level is greater than \$2.26 million (50% of the \$4.53 million 13.01.1(b) differential)
17 that would have been a consolidated tax adjustment prior to Act 40 of 2016.

18 **Q. Can you summarize the impact of your testimony on historic and**
19 **proposed income tax expense?**

20 A. Yes, for the Historic Test Year, Exhibit 7, Page 19, Line 35, Column 2 delineates total
21 pro forma tax expense of \$55,866,632. This total includes \$6,300,298 of state
22 income taxes (Exhibit 7, Page 19, Line 34), which is based on \$325,933,479 of
23 operating income (Exhibit 7, Page 19, Line 1) less \$75,096,934 of interest expense

on debt (Exhibit 7, Page 19, Line 5) for total pre-tax income of \$250,836,549 resulting in an effective state income tax rate of 2.51%. The reduced state effective tax rate, as compared to the Pennsylvania statutory rate of 8.49%, is a result of the flow through treatment of repairs deductions and Pennsylvania NOL carryforward deductions for state income tax purposes. The expense for federal income taxes is \$49,566,334 (Exhibit 7, Page 19, Line 33) resulting in an effective tax rate of 19.76%. The decreased federal effective tax rate, as compared to the federal statutory rate of 21%, is largely attributable to the flow-through of the amortization of excess accumulated deferred income taxes related to the reduction of the corporation federal income tax rate from 35% to 21% as a result of the enactment of TCJA.

Q. Please continue with respect to the Fully Projected Future Test Year.

A. For the Fully Projected Future Test Year, Exhibit 107, Page 16, Line 35 delineates total income tax expense of \$72,811,341. This total includes \$12,777,404 of state income taxes (Exhibit 107, Page 16, Line 34), which is based on \$401,512,722 of operating income (Exhibit 107, Page 16, Line 1) less \$91,366,270 of interest expense on debt (Exhibit 107, Page 16, Line 5) for total pre-tax income of \$310,146,452 resulting in an effective state income tax rate of 4.12%. The reduced state effective tax rate, as compared to the Pennsylvania statutory rate of 7.49%, is a result of the flow through treatment of the repairs deductions and flow through deductions for bonus depreciation that was disallowed in prior years for state income tax purposes. The Company notes that the remaining Pennsylvania NOL carryforward was fully utilized in the Historic Test Year. The expense for federal income taxes is \$60,033,937 (Exhibit 107, Page 16, Line 33) resulting in an effective tax rate of

1 19.36%. The decreased federal effective tax rate, as compared to the federal statutory
2 rate of 21%, is largely attributable to the flow-through of the amortization of excess
3 accumulated deferred income taxes related to the reduction of the corporation
4 federal income tax rate from 35% to 21% as a result of the enactment of TCJA.

5 **Q. How does deferred income taxes impact the Company's rate base?**

6 A. Exhibit 107, Page 5, delineates the reduction in rate base for Federal deferred income
7 taxes and federal excess deferred income taxes. The amounts include deferred taxes
8 on net utility plant are normalized for the Fully Projected Future Test Year ending
9 December 31, 2026, as well as federal and state deferred income taxes on capitalized
10 inventory and customer advances.

11 **Q. How has the deduction for 263A mixed service costs impacted deferred**
12 **taxes in rate base?**

13 A. As agreed in the Commission-approved settlement of Columbia's 2012 rate case (R-
14 2012-2321748), the Company is authorized to normalize this deduction for federal
15 income taxes and treat the deferred taxes as a reduction to rate base. The adjustment
16 can be found on Exhibit 107, Page 16, Line 17.

17 **Q. Is there an inclusion of deferred taxes for the Federal NOL in rate base?**

18 A. In the Historic Test Year, the deferred tax asset for the Federal NOL, which
19 represents the remaining balance of un-utilized net operating loss, is \$39,244,483
20 as shown in Exhibit 7, Page 9, Line 6 and deficient deferred taxes of \$23,105,931 as
21 shown in Exhibit 7, Page 9, Line 46 attributed to the remeasurement of the federal
22 income tax rate to 21% under TCJA. The Company has incurred a tax loss for federal
23 purposes in tax years 2008, 2010, 2011, 2012, 2013, 2016, and 2017, as a result of

1 taking deductions for 50-100% bonus depreciation, resulting in the deferred tax
2 asset being recorded for the un-utilized net operating losses. The deferred tax asset
3 represents the cash benefits the Company has not received because of the net
4 operating losses. The deferred tax asset is included in rate base because the Company
5 cannot reflect an increase in deferred taxes for tax depreciation deductions that have
6 not been realized. To do so would violate the principles of the normalization
7 requirements under the Internal Revenue Code. Past IRS rulings addressing this
8 issue have made it clear that companies cannot reduce rate base for benefits that
9 have not been realized. The deferred tax asset for the un-utilized net operating losses
10 for the Fully Projected Future Test Year is primarily due to repairs and accelerated
11 depreciation deductions. Due to the net operating losses generated by bonus
12 depreciation deductions in the aforementioned years and the modifications to the
13 Federal NOL under the TCJA, the expectation is that the Company will not utilize all
14 of its net operating losses until beyond the Fully Projected Future Test Year.
15 Therefore, there is an increase to rate base on Exhibit 107, Page 5a.2, Line 6 of
16 \$32,600,836 as a deferred tax asset for the unutilized Federal NOL carryforward
17 and deficient deferred taxes of \$20,609,358 as shown in Exhibit 107, Page 5a.2, Line
18 46 attributed to the remeasurement of the federal income tax rate to 21% under
19 TCJA for the Fully Projected Future Test Year ending December 31, 2026.

20 **Q. Please explain the adjustment to deferred taxes for the Fully Projected**
21 **Future Test Year on Exhibit 107, Page 5.**

22 A. Whenever there are estimated changes in the deferred taxes that occur in a future
23 rate period, the normalization requirements of the Internal Revenue Code require

1 that the deferred taxes be reflected on a pro rata basis as provided under Regulations
2 Section 1.167(l)-1(h)(6)(ii). A future test period is defined as that portion of the test
3 period after the effective date of the rate order. Under the pro rata basis, the change
4 in the deferred taxes is determined by multiplying the change by a fraction of the
5 number of days remaining in the period at the time such change is to be accrued over
6 the total number of days in the future period. Applying this calculation resulted in a
7 decrease to deferred taxes of \$15,212,142 computed on Exhibit 107, Page 5b, Line
8 23.

9 **Q. Are you sponsoring any other expense adjustments?**

10 A. Yes. I am also sponsoring adjustments for Federal Insurance Contribution Act
11 (“FICA”) Tax, Property Tax, and License and Franchise Tax. These adjustments are
12 delineated on Exhibits 6 for the Historic Test Year and 106 for the Future Test Year
13 and Fully Projected Future Test Year.

14 **Q. Please explain the FICA adjustment.**

15 A. The adjustment represents an increase in FICA taxes as they apply to the labor
16 charged to Operation & Maintenance Expense (See Exhibit No. 4, Schedule 1, Page
17 2 Lines 1 and 2). A decrease in payroll taxes of \$143,848 is reflected in the annualized
18 Historic Test Year presented on Exhibit No. 6, Schedule 2, Page 3, Line 7 for the
19 calculation. For the Fully Projected Future Test Year, the Company is projecting a
20 lower payroll base compared to the Future Test Year, thus decreasing payroll taxes
21 by \$41,533 as reflected on Exhibit No. 106, Schedule 2, Page 3, Line 6 for the
22 calculation.

23 **Q. Please explain the property tax adjustment.**

1 A. The PURTA tax and the locally assessed property tax on Pennsylvania property are
2 both consistent with the most recent year-end tax levels as of December 31, 2023.
3 The West Virginia tax for gas stored underground was developed using the
4 December 31, 2023, assessed value and the 2023 tax rate. This annualized level is
5 increased compared to the Historic Test Year level of \$871,738, as shown on Exhibit
6 6, Schedule 2, Page 4, Line 8. The detail supporting this calculation for the Fully
7 Projected Future Test Year is provided on Exhibit 106, Schedule 2, Page 4. The pro
8 forma Fully Projected Future Test Year reflects a decreased adjustment of \$59,673
9 from the annualized level primarily as a result of the increased West Virginia stored
10 gas December 31, 2023 assessed value and the 2023 tax rate which is the latest
11 available at this time.

12 **Q. Please explain the Other Tax adjustment on Exhibit 106, Schedule 2,**
13 **Page 2.**

14 A. Other taxes are primarily comprised of excise tax. The annualized level of \$7,069
15 was not adjusted for the Historic Test Year. The pro forma Fully Projected Future
16 Test Year was also not adjusted from this level.

17 **Q. Does this conclude your prepared Direct Testimony?**

18 A. Yes.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
JULIE E. COVERT
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

I. Introduction

Q. Please state your name and business address.

A. My name is Julie E. Covert, and my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

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

A. I am employed by NiSource Corporate Services Company ("NCSC"), as Lead Regulatory Analyst.

Q. What are your responsibilities as Lead Regulatory Analyst?

A. I am responsible for supporting the NiSource Inc. ("NiSource") operating companies in a variety of informational and rate filings, general rate case preparation and support, and other duties as assigned.

Q. What is your educational and professional background?

A. I have a Bachelor of Science in Business Administration from Franklin University. My career began at NiSource in 2007 providing general accounting support for Columbia Gas of Virginia, Inc. ("CVA"). Since 2007, I have worked on Asset Accounting matters for the Columbia Distribution Companies, which includes Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company"), before transferring into my current Lead Regulatory Analyst role in 2015.

Q. Have you ever testified before a regulatory Commission?

A. Yes, I was the Rate Base witness for Columbia before the Public Utility Commission in Docket Nos. R-2018-2647577, R-2022-3031211 and R-2024-3046519, and for CVA before the State Corporation Commission in Docket No. PUR-2018-00131.

II. Statement of Purpose

Q. Please describe the purpose of your testimony in this proceeding.

A. I will present schedules that demonstrate Columbia's rate base as of December 31, 2026, which reflects the Fully Projected Future Test Year ("FPFTY") investment level that is utilized within the revenue requirement supported by Columbia witness Vassalotti (Columbia Statement No. 4). My testimony will support and detail the various components included in rate base. I am also sponsoring the following exhibits:

<u>Exhibit No.</u>	<u>Description</u>
Exhibit No. 8	Historic Test Year ("HTY") rate base
Exhibit No. 13, Schedule 6 (27)	Schedule of gas producing units retired or scheduled for retirement
Exhibit No. 108	Future Test Year ("FTY") and FPFTY rate base
Exhibit No. 113, Schedule 4 (27)	Schedule of gas producing units retired or scheduled for retirement
Exhibit No. 408, Page 1 (11)	AFUDC and method of rate calculation
Exhibit JEC-1 (Attached hereto)	Update of Exhibit 108, Schedule 1 from Docket No. R-2024-3046519 (Updated through December 31, 2024)
Exhibit JEC-2 (Attached hereto)	Comparison of actual rate base additions for the twelve months ended December 31, 2024

Q. What test years will you be addressing in your testimony?

A. I will be addressing the twelve-month period ending November 30, 2024 as the HTY (Exhibit 8), the twelve-month period ended November 30, 2025 as the FTY (Exhibit

108), and the twelve-month period ended December 31, 2026 as the FPFTY (Exhibit 108).

3 **III. Rate Base**

4 **Q. Is the FPFTY utilized by Columbia in this case similar to that used in its**
5 **prior base rate cases?**

6 A. Yes. Columbia elected to use the FPFTY provided in Act 11 of 2012 in Docket Nos. R-
7 2012-2321748, R-2014-2406274, R-2015-2468056, R-2016-2529660, R-2018-
8 2647577, R-2020-3018835, R-2021-3024296, R-2022-3031211, and R-2024-
9 3046519. The Company is making the same election in the current case. Also, the
10 presentation of rate base in this case is the same as the prior cases.

11 **Q. Are there any requirements from prior cases arising from the Company's**
12 **use of a FPFTY?**

13 A. Yes. Pursuant to Paragraph 30 of the Settlement in the Company's prior rate case at
14 Docket No. R-2024-3046519, Columbia is required to provide to the Commission
15 and the statutory parties, on or before April 1, 2025, an update to Columbia Exhibit
16 108, Schedule 1, which is to include actual capital expenditures, plant additions and
17 retirements by month for the twelve months ending December 31, 2024. This update
18 is attached to my testimony as Exhibit JEC-1.

19 In addition, Columbia is required to provide a comparison of rate base
20 additions for the twelve months ended December 31, 2025. This data will be provided
21 when it becomes available. A comparison of rate base additions for the twelve
22 months ended December 31, 2024, is attached to my testimony as Exhibit JEC-2.

Q. Please comment on how the Company's actual plant additions for the 12-month period ending December 31, 2024 compares to the projections made in Columbia's prior rate case at Docket No. R-2024-3046519.

A. The Company's actual plant additions for the twelve-month period ending December 31, 2024, exceeded projections submitted in Docket No. R-2024-3046519 by \$13 million, as shown in the Table JEC-1 below.

TABLE JEC-1			
<u>Budget to Actual - Plant Additions</u>			
TME December 31, 2024			
	<u>Budget¹</u>	<u>Actual²</u>	<u>Variance</u>
Additions	\$ 415,867,882	\$ 436,762,405	\$ 20,894,524
Retirements	\$ (45,108,502)	\$ (52,981,373)	\$ (7,872,871)
Net Plant	\$ 370,759,380	\$ 383,781,033	\$ 13,021,653
¹ Docket No. R-2024-3046519			
² Exhibit JEC-1			

Q. Please explain the development of rate base at November 30, 2024 for the HTY, November 30, 2025 for the FTY and December 31, 2026 for the FPFTY.

A. Rate base is summarized on Exhibit 8, Page 3, and further detailed by the various components in Exhibit 8, Schedules 1-10, for the HTY. Rate base for the FTY and the FPFTY are summarized on Exhibit 108, Page 3, and further detailed by various components in Exhibit 108, Schedules 1-10.

Q. Please discuss the amounts included in Property, Plant and Equipment for the HTY as illustrated on Exhibit 8, Page 3, Lines 1-9.

1 A. The Company's Plant in Service includes plant in service per books as of November
2 30, 2024. Accounts 101 and 106 are detailed in Lines 2 through 4. Note, the plant
3 detail for Leases (Line 4) is separately provided, as Leases are removed from rate
4 base. The Company is not making a claim for Construction Work in Progress
5 ("CWIP") as of the end of the HTY as noted in Line 5. The HTY also includes per
6 books Gas Stored Underground – Non-Current, Account 117 on Exhibit 8, Page 3,
7 Line 6.¹ Reductions are included for the Depreciation Reserve, per Company witness
8 Spanos (Columbia Statement No. 5) on Line 7. Finally, Gas Lost - Underground
9 Storage is on Line 8.

10 **Q. Please explain how the Company's FTY and FPFTY Property, Plant and**
11 **Equipment were developed.**

12 A. The Company's Plant in Service as of December 31, 2026, as shown on Exhibit 108,
13 Schedule 1, Pages 1-14 was developed beginning with Plant in Service at November
14 30, 2024 (Column 2). Forecasted Plant additions based on the Company's current
15 capital plan were added in columns 3 and 6, while forecasted retirements supported
16 by Company witness Spanos (Columbia Statement No. 5) were subtracted in columns
17 4 and 7. Exhibit 108, Schedule 1, Page 14, Column 6 reflects the net forecasted plant
18 in service included in rate base as of December 31, 2026. Additional details
19 surrounding the budget is discussed by Company witness Brumley (Columbia
20 Statement No. 7).

¹ I note that, on January 29, 2025, Columbia filed an application for Commission approval to transfer ownership of its Blackhawk Storage Field (Docket No. A-2025-3053161). If the sale is approved before the record in this case is closed, this claimed item will be removed from this case. Corresponding adjustments will be made for FTY and FPFTY data in Exhibit 108.

1 **Q. Please explain Exhibit 8, Schedule 2.**

2 A. This Exhibit reflects the balance in CWIP. The Company is not making a claim for
3 CWIP in the HTY.

4 **Q. Please explain Exhibit 108, Schedule 2.**

5 A. Exhibit 108, Schedule 2 shows that forecasted CWIP, Account 107, is expected to
6 remain at the same level for the FPFTY as it was at November 30, 2024. The
7 Company is making no claim for CWIP in the FPFTY.

8 **Q. Please explain the credits to Gas Plant in Service on Exhibit 8, Page 3,**
9 **Lines 7-8 and Exhibit 108, Page 3, Lines 6-7.**

10 A. Line 7, Depreciation Reserve, Accounts 108-111 in Exhibit 8, Page 3 for the HTY and
11 Line 6, Exhibit 108, Page 3 for the FPFTY are detailed and supplied by Company
12 witness Spanos, by plant account, in Exhibit 5 for the HTY and Exhibit 105 in the
13 FPFTY. Exhibit 8, Page 3, Line 8 and Exhibit 108, Page 3, Line 7 Accumulated
14 Provision for Gas Lost – Underground Storage, Account 117, is per books as of
15 November 30, 2024 for the HTY and December 31, 2026 for the FPFTY.

16 **Q. Did you include Materials and Supplies inventory balances in rate base?**

17 A. Yes. As shown on Exhibit 8, Schedule 5, Materials and Supplies included in the HTY
18 rate base is a 13-month average of the historical monthly balances in Plant Materials,
19 Account 154. Materials and Supplies in the FTY rate base as shown on Exhibit 108,
20 Schedule 5 begins with November and December 2024 actual balances (most
21 recently available), continuing with January 2025 through November 2025 balances
22 calculated by applying the Gross Domestic Product (“GDP”) deflator supported by

1 Company witness Vassalotti (Columbia Statement No. 4) in Exhibit 104, Schedule 2,
2 Page 20, to the actual balances of January 2024 through November 2024. The GDP
3 deflator is further applied to the FTY balances to arrive at the FPFTY balances.

4 **Q. Did you include Prepayment balances in rate base?**

5 A. Yes. Exhibit 8, Schedule 6 for the HTY shows prepayments for: Prepaid Leases,
6 Account 16500000; Corporate Insurance, Account 16521000; Prepaid Insurance
7 I/C, Account 1652000; Regulatory Commission Fees, Office of Consumer Advocate
8 (“OCA”) fees, and Office of Small Business Advocate (“OSBA”) fees, Account
9 16503600; and Prepaid Permits, Account 16503700. The amount in the HTY rate
10 base is based on a 13-month average of historic monthly balances per the Company’s
11 books. Exhibit 108, Schedule 6 for the FPFTY shows prepayments for: Prepaid
12 Leases, Account 16500000; Corporate Insurance, Account 16521000; Prepaid
13 Insurance I/C, Account 1652000; Regulatory Commission Fees, OCA, and OSBA
14 fees, Account 16503600; and Prepaid Permits, Account 16503700. The amounts for
15 the FPFTY rate base were determined by incrementally applying the GDP deflators
16 supported by Company witness Vassalotti in Exhibit 104, Schedule 2, Page 20 to the
17 January 2024 through November 2024 actual balances to reflect expected new
18 prepayments as of December 2026.

19 **Q. Did you include Gas Stored Underground in rate base?**

20 A. Yes, I did.

21 **Q. What valuation methodology is applied to Gas Stored Underground?**

1 A. As per the Commission's March 31, 2001 Order at Docket No. P-2010-2209925,
2 Columbia uses the Weighted Average Cost of Gas ("WACOG") methodology to value
3 Storage Gas.

4 **Q. Please describe the WACOG accounting methodology you applied to**
5 **value the FPFTY storage balance.**

6 A. Under the WACOG accounting methodology, the actual cost and volume of the
7 current month's injections are added to the inventory value calculated at the end of
8 the previous month, and a new average cost per Dth is calculated for the current
9 month. The current month's withdrawals are deducted from the balance at the new
10 average cost per Dth. When storage gas is being injected (April – October), the
11 inventory cost for the current month is added to the inventory cost from the previous
12 month(s). At the end of injection season, the storage cost for the winter is well
13 established. During the withdrawal season (November – March), withdrawals are
14 made at the average price primarily resulting from the injection season.

15 **Q. Did you include an adjustment to Gas Stored Underground in rate base?**

16 A. Yes. I have calculated a twelve-month average cost of gas to be included in rate base.

17 **Q. Do you provide exhibits supporting this storage adjustment?**

18 A. Yes, I do.

19 **Q. Please identify and explain those exhibits.**

20 A. The supporting exhibits are Exhibit 8, Schedule 7 and Exhibit 108, Schedule 7. The
21 actual December 2023 through November 2024 injections and withdrawals are
22 reflected on Exhibit 8, Schedule 7 in columns A and E, respectively. A projected

1 Monthly Average Cost of Gas is detailed in Column B of Exhibit 8, Schedule 7.
2 Therefore, under the WACOG accounting methodology, the current month's
3 injections (Column A) are multiplied by the Monthly Average Cost of Gas (Column
4 B). The result is added to the inventory value calculated at the end of the previous
5 month (Column I), and a new WACOG per Dth is calculated (Column D) for the
6 current month. The current month's withdrawals (Column E) are multiplied by the
7 new WACOG per Dth (Column D) and the result is deducted from the cumulative
8 balance (Column I). Adjustments (Column G) reflect prior month's adjustments.
9 This method is continued every month through November 2024, as shown in Exhibit
10 8, Schedule 7. Exhibit 8, Schedule 7, Line 14 calculates a twelve-month average
11 storage balance to be included in the Pro Forma Rate Base.

12 Exhibit 108, Schedule 7 repeats this process from November 2024 through
13 December 2026. Injection rates are based on NYMEX Natural Gas Futures. Lines
14 27 and 28 calculate a twelve-month average storage balance for the FTY rate base
15 and FPFTY rate base, respectively.

16 **Q. Did you include Deferred Income Taxes in rate base?**

17 A. Yes, I did. Balances as of November 30, 2024 pertaining to Deferred Income Taxes
18 included in rate base are shown on Exhibit 8, Schedule 8. The balances were supplied
19 by Company witness Harding (Columbia Statement No. 10) on Exhibit 7, Page 9.
20 Forecasted balances as of November 30, 2025 and December 31, 2026 pertaining to
21 Deferred Income Taxes included in rate base are shown on Exhibit 108, Schedule 8.
22 These were supplied by Company witness Harding on Exhibit 107, Page 5.

1 **Q. How did you determine the Customer Deposits in rate base?**

2 A. Customer Deposits, Account 235, is a 13-month historic average, as detailed on
3 Exhibit 8, Schedule 9 for the HTY. The 13-month average for the forecasted rate base,
4 detailed on Exhibit 108, Schedule 9, reflects projected balances for November 2025
5 through December 2026, with entries for November and December of each year
6 based on actual data for November and December of 2024. The balances for January
7 2025 – December 2026 are based on HTY balances.

8 **Q. Please explain the Company's accounting for Contributions in Aid of**
9 **Construction and Customer Advances.**

10 A. Customer Advances for Construction are classified to the 252 and 186 Accounts. This
11 includes advances by customers for construction which are to be refunded either
12 wholly or in part. Once the customer advance is received, it is journaled as a credit
13 to the 252 Account and a debit to Cash (Account 131). The next month a journal entry
14 is made to debit the 186 Account and credit the Capital asset (Account 101).

15 The calculation of rate base includes the Customer Advances 252 and 186
16 Accounts as well as the Capital Asset (Account 101). Therefore, rate base has
17 appropriately been reduced by amounts paid by customers.

18 If the advance is refunded, then a debit is made against the Capital asset
19 (Account 101), and the customer is issued a refund. Additionally, an entry is made to
20 reduce the balances in Accounts 186 and 252. However, if the customer advance is
21 deemed non-refundable, it becomes a Contribution in Aid of Construction and
22 remains as a credit to the Capital asset.

Customer Advances for Construction are reflected on Exhibit 8, Page 3, line 25 for the HTY and Exhibit 108, Page 3, line 25 for the FTY and FPFTY.

IV. Distribution System Improvement Charge

Q. Please describe the Distribution System Improvement Charge (“DSIC”).

A. The DSIC was designed to allow for recovery of reasonable and prudent costs incurred to repair, improve or replace eligible property, which has been completed and placed in service, but which is not being recovered through base rates.

Q. Is Columbia currently charging a DSIC?

A. No. Columbia reset its DSIC to 0% when the Company made its compliance filing to implement rates approved in the rate case at Docket No. R-2024-3046519. However, Columbia will file Tariff Supplement No. 395 on March 21, 2025, to become effective April 1, 2025, to update the DSIC rate to recover the under collection from the Rider DSIC for the 12 months ended December 31, 2024.

Q. When will the Company be eligible to include plant additions in the DSIC?

A. Consistent with the Company’s Tariff, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company’s rates or rate base may be reflected in quarterly updates of the DSIC. Pursuant to the Settlement of the Company’s rate case in Docket No. R-2024-3046519, the Company will be eligible to include plant additions in the DSIC at the later of (1) the end of the FPFTY (which was December 31, 2025 in that rate case), or (2) once the total FPFTY account

1 balances exceed \$4,815,151,833, as projected by Columbia at December 31, 2025, per
2 Exhibit No. 108, Schedule 1.

3 **V. Other Exhibits**

4 **Q. Please explain the purpose of Page 2 of Exhibit 8.**

5 A. This page satisfies 52 Pennsylvania Code Section 53.53 I.A, item 2 of the
6 Commission's standard filing requirements, which provides that Exhibit 8, Page 4,
7 shows the Company's rate base claim from its last base rate proceeding.

8 **Q. Does this conclude your prepared Direct Testimony?**

9 A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated For Actuals Through December 31, 2024
R-2024-3046519

Line	Account	Beginning Balance	Balance as of	Balance as of
No.	Description	No.	1/31/2024	2/29/2024
		(1)	(5 = 2+3+4)	(8)=(5+6+7)
		(2)	(6)	(9)
		\$	\$	\$
1	<u>Intangible Plant</u>			
2	Organization Costs	301.00	100,099	0
3	Franchises/Consent, Perpetual	302.10	26,216	0
4	Intangible Plant, General	303.00	4,809,062	0
5	Intangible Plant, Miscellaneous Software	303.30	52,579,183	129,691
6	Cloud Software	303.99	7,683,664	116,122
7	<u>Underground Storage Plant</u>			
8	Land	350.10	23,882	0
9	Rights of Way	350.20	1,932	0
10	Compressor Station Structures	351.20	3,294,840	0
11	Wells Construction	352.01	1,126,772	0
12	Wells Equipment	352.02	1,072,970	0
13	Storage Leasehold and Rights	352.10	139,442	0
14	Other Leases	352.12	67,498	0
15	Lines	353.00	387,525	0
16	Compressor Station Equipment	354.00	947,638	0
17	Measuring & Regulating Equipment	355.00	104,477	0
18	<u>Distribution Plant</u>			
19	Land, City Gate/Main Line Industrial	374.10	21,944	0
20	Land, Other Distribution System	374.20	3,361,034	0
21	Land Rights, City Gate/Main Line	374.30	95,361	0
22	Land Rights, City Other Distribution System	374.40	8,012,420	78,214
23	Land Rights, City Other Distribution System, Loc	374.41	13	0
24	Rights of Way	374.50	3,233,025	289
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0
27	Structures, Regulating	375.40	6,508,005	8,240
28	Structures, Distribution Industrial M&R	375.60	86,084	0
29	Structures, Other Distribution System	375.70	49,536,882	94,854
30	Structures, Other Distribution System, Leased	375.71	5,322,270	0
31	Structures, Communication	375.80	16,515	0
32	Mains	376.00	2,666,976,114	8,391,097
33	Mains - CSL Replacements	376.08	23,515,481	0
34	Bare Steel	376.30	60,286,708	361
35	Cast Iron	376.80	148,787	0
36	Measuring & Regulating Equipment General	378.10	1,442,966	0
37	Measuring & Regulating Equipment Regulating	378.20	143,758,484	71,701
38	Measuring & Regulating Equipment Local Gas	378.30	406,758	0
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0
40	Measuring & Regulating Equipment Exchange Gas	379.11	(903)	0
41	Services	380.00	815,105,240	2,848,976
42	Meters	381.00	45,848,012	113,492
43	Auto Meter Reading Devices	381.10	24,668,228	0
44	Meter Installations	382.00	46,168,212	339,454
45	House Regulators	383.00	18,025,015	111,886
46	House Regulators Installations	384.00	3,484,788	0
47	Industrial M&R Equipment. Station Equipment	385.00	6,864,025	715
48	Industrial M&R Equipment. Large Volume	385.10	995,901	0
49	Other Equipment	387.10	19,450	0
50	Other Equipment, Odorization	387.20	117,248	0
51	Other Equipment, Radio	387.42	119,609	0
52	Other Equipment, Other Communications	387.44	566,537	0
53	Other Equipment, Telemetering	387.45	15,104,814	42,960
54	Other Equipment, Customer Information Service	387.46	259,436	0
55	GPS Pipe Locators	387.50	2,201,372	0
56	<u>General Plant</u>			
57	Structures, Communications	390.10	49,821	0
58	Office Furniture & Equipment, Unspecified	391.10	3,720,511	0
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0
60	Office Furniture & Equipment, Information Systems	391.12	554,184	0
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0
62	Transportation Equipment, Trailers > \$1,000	392.20	14,787	0
63	Transportation Equipment, Trailers \$1,000 or <	392.21	10,830	0
64	Stores Equipment	393.00	0	0
65	Tools, Garage & Service Equipment	394.10	395,117	0
66	Tools, CNG Equipment, Stationary	394.11	18,450	0
67	Tools, CNG Equipment, Portable	394.12	0	0
68	Tools, Shop Equipment	394.20	0	0
69	Tools, Tools and Other	394.30	20,378,022	10,380
70	Tools, High Pressure Stopping	394.31	10,847	83,827
71	Laboratory Equipment Gas	395.00	264,921	0
72	Power Operated Equipment	396.00	948,698	0
73	Communication Equipment	397.00	0	0
74	Communication Equipment, Telephone	397.10	0	0
75	Communication Equipment, Radio	397.20	0	0
76	Communication Equipment, Other	397.40	0	0
77	Communication Equipment, Telemetering	397.50	770,403	0
78	Miscellaneous Equipment	398.00	1,027,393	22,000
79	Total Gas Plant in Service		4,053,027,425	12,453,590
			(3,908,129)	4,061,572,886
			10,956,610	(1,286,883)
				4,071,242,613

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated For Actuals Through December 31, 2024
R-2024-3046519

Line		Account	Beginning Balance			Balance as of			Balance as of
No.	Description	No.	2/29/2024	Additions	Retirements	3/31/2024	Additions	Retirements	4/30/2024
		(1)	(2)	(3)	(4)	(5 = 2+3+4)	(6)	(7)	(8)=(5+6+7)
			\$	\$	\$	\$	\$	\$	\$
1	<u>Intangible Plant</u>								
2	Organization Costs	301.00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	51,571,636	(1,063,155)	(15,052)	50,493,429	1,344,329	(7,617,514)	44,220,244
6	Cloud Software	303.99	7,812,739	23,660	0	7,836,399	(8,214)	0	7,828,185
7	<u>Underground Storage Plant</u>								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0	1,126,772
12	Wells Equipment	352.02	1,072,970	0	0	1,072,970	0	0	1,072,970
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	387,525	0	0	387,525	0	0	387,525
16	Compressor Station Equipment	354.00	947,638	0	0	947,638	0	0	947,638
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	<u>Distribution Plant</u>								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,034	0	(2)	3,361,033	0	0	3,361,033
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	8,099,415	43,677	0	8,143,091	5,377	0	8,148,469
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,314	0	0	3,233,314	0	0	3,233,314
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	6,488,977	6,316	0	6,495,293	0	(3,618)	6,491,675
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	0	86,084
29	Structures, Other Distribution System	375.70	49,508,005	(56)	0	49,507,949	26,836	0	49,534,785
30	Structures, Other Distribution System, Leased	375.71	5,322,270	0	0	5,322,270	5,991	0	5,328,261
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains	376.00	2,679,995,158	14,082,060	(1,971,538)	2,692,105,680	13,132,077	(237,955)	2,704,999,802
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
34	Bare Steel	376.30	60,226,080	(357)	(43,538)	60,182,184	2	(17,894)	60,164,293
35	Cast Iron	376.80	148,787	0	0	148,787	0	0	148,787
36	Measuring & Regulating Equipment General	378.10	1,442,966	0	0	1,442,966	0	0	1,442,966
37	Measuring & Regulating Equipment Regulating	378.20	143,680,485	73,186	(59,019)	143,694,651	3,881,475	(36,121)	147,540,005
38	Measuring & Regulating Equipment Local Gas	378.30	406,301	0	0	406,301	0	0	406,301
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(903)	0	0	(903)	0	0	(903)
41	Services	380.00	820,402,960	4,887,236	(1,313,577)	823,976,619	4,396,010	(8,558)	828,364,071
42	Meters	381.00	45,864,213	154,800	(40,979)	45,978,035	310,300	(77,827)	46,210,508
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	0	0	24,668,228
44	Meter Installations	382.00	46,597,139	165,186	(60,582)	46,701,743	143,035	0	46,844,779
45	House Regulators	383.00	18,268,597	112,670	(19,204)	18,362,063	105,730	0	18,467,793
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,860,458	9,098	0	6,869,556	41,439	(282)	6,910,713
48	Industrial M&R Equipment. Large Volume	385.10	994,610	0	0	994,610	0	(1,032)	993,577
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	566,537	0	0	566,537	0	(439)	566,098
53	Other Equipment, Telemetering	387.45	15,214,807	307,006	(26,521)	15,495,292	5,296	(105,681)	15,394,907
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	<u>General Plant</u>								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,720,511	0	0	3,720,511	0	0	3,720,511
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	554,184	0	0	554,184	0	0	554,184
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0	0
62	Transportation Equipment, Trailers > \$1,000	392.20	14,787	0	0	14,787	0	0	14,787
63	Transportation Equipment, Trailers \$1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	395,117	0	0	395,117	0	0	395,117
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	20,383,215	101,012	(2,000)	20,482,227	312,416	0	20,794,643
70	Tools, High Pressure Stopping	394.31	66,413	0	0	66,413	0	0	66,413
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	770,403	0	0	770,403	0	0	770,403
78	Miscellaneous Equipment	398.00	1,049,393	8,000	0	1,057,393	76,165	0	1,133,558
79	Total Gas Plant in Service		4,071,242,613	18,910,340	(3,552,012)	4,086,600,941	23,778,265	(8,106,922)	4,102,272,284

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
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Line	Account	Beginning			Balance			Balance
No.	Description	No.	4/30/2024	Additions	Retirements	5/31/2024	Additions	Retirements
		(1)	(2)	(3)	(4)	(5 = 2+3+4)	(6)	(7)
			\$	\$	\$	\$	\$	\$
1	<u>Intangible Plant</u>							
2	Organization Costs	301.00	100,099	0	0	100,099	0	0
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0
5	Intangible Plant, Miscellaneous Software	303.30	44,220,244	2,506,738	(104,941)	46,622,041	724,254	(653,667)
6	Cloud Software	303.99	7,828,185	24,401	0	7,852,586	571	0
7	<u>Underground Storage Plant</u>							
8	Land	350.10	23,882	0	0	23,882	0	0
9	Rights of Way	350.20	1,932	0	0	1,932	0	0
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0
12	Wells Equipment	352.02	1,072,970	0	0	1,072,970	0	0
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0
14	Other Leases	352.12	67,498	0	0	67,498	0	0
15	Lines	353.00	387,525	0	0	387,525	0	0
16	Compressor Station Equipment	354.00	947,638	0	0	947,638	0	0
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0
18	<u>Distribution Plant</u>							
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0
20	Land, Other Distribution System	374.20	3,361,033	0	0	3,361,033	0	0
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0
22	Land Rights, City Other Distribution System	374.40	8,148,469	(114)	0	8,148,355	0	0
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0
24	Rights of Way	374.50	3,233,314	0	0	3,233,314	0	0
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0
27	Structures, Regulating	375.40	6,491,675	0	0	6,491,675	5,320	0
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	0
29	Structures, Other Distribution System	375.70	49,534,785	225,567	(845)	49,759,507	58,228	0
30	Structures, Other Distribution System, Leased	375.71	5,328,261	239,601	0	5,567,863	25,399	0
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0
32	Mains	376.00	2,704,999,802	16,988,324	(23)	2,721,988,102	20,264,831	(214,303)
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0
34	Bare Steel	376.30	60,164,293	0	(22)	60,164,271	0	0
35	Cast Iron	376.80	148,787	0	0	148,787	0	0
36	Measuring & Regulating Equipment General	378.10	1,442,966	0	0	1,442,966	0	0
37	Measuring & Regulating Equipment Regulating	378.20	147,540,005	23,557	(59,794)	147,503,768	394,869	(693,002)
38	Measuring & Regulating Equipment Local Gas	378.30	406,301	0	0	406,301	0	0
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0
40	Measuring & Regulating Equipment Exchange Gas	379.11	(903)	0	0	(903)	0	0
41	Services	380.00	828,364,071	5,661,555	(832,175)	833,193,451	5,263,126	(922,698)
42	Meters	381.00	46,210,508	76,528	(53,927)	46,233,109	318,558	(70,894)
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	0	0
44	Meter Installations	382.00	46,844,779	133,650	(35,084)	46,943,345	200,844	(19,748)
45	House Regulators	383.00	18,467,793	116,026	(5,063)	18,578,756	109,014	(2,795)
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0
47	Industrial M&R Equipment. Station Equipment	385.00	6,910,713	8,958	(5,997)	6,913,674	0	(7,293)
48	Industrial M&R Equipment. Large Volume	385.10	993,577	0	0	993,577	0	0
49	Other Equipment	387.10	19,450	0	0	19,450	0	0
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0
52	Other Equipment, Other Communications	387.44	566,098	595	(3,337)	563,356	0	0
53	Other Equipment, Telemetering	387.45	15,394,907	129,020	(24,043)	15,499,884	227,123	0
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0
56	<u>General Plant</u>							
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0
58	Office Furniture & Equipment, Unspecified	391.10	3,720,511	0	(21,845)	3,698,665	0	0
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0
60	Office Furniture & Equipment, Information Systems	391.12	554,184	0	0	554,184	3,376	0
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0
62	Transportation Equipment, Trailers > \$1,000	392.20	14,787	0	0	14,787	0	0
63	Transportation Equipment, Trailers \$1,000 or <	392.21	10,830	0	0	10,830	0	0
64	Stores Equipment	393.00	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	395,117	0	(7,377)	387,740	0	0
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	20,794,643	120,753	(9,833)	20,905,563	174,652	0
70	Tools, High Pressure Stopping	394.31	66,413	0	0	66,413	0	0
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0
73	Communication Equipment	397.00	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	770,403	0	0	770,403	0	0
78	Miscellaneous Equipment	398.00	1,133,558	15,734	0	1,149,293	(33,000)	0
79	Total Gas Plant in Service		<u>4,102,272,284</u>	<u>26,270,894</u>	<u>(1,164,305)</u>	<u>4,127,378,873</u>	<u>27,737,165</u>	<u>(2,584,400)</u>
								<u>4,152,531,638</u>

Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
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Line No.	Account Description	Account No.	Beginning Balance 6/30/2024	Additions	Retirements	Balance as of 7/31/2024	Additions	Retirements	Balance as of 8/31/2024
		(1)	(2)	(3)	(4)	(5 = 2+3+4)	(6)	(7)	(8)=(5+6+7)
			\$	\$	\$	\$	\$	\$	\$
1	<u>Intangible Plant</u>								
2	Organization Costs	301.00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	46,692,628	324,464	(472,521)	46,544,571	1,335,600	(137,942)	47,742,229
6	Cloud Software	303.99	7,853,157	973,309	0	8,826,466	(31,981)	0	8,794,485
7	<u>Underground Storage Plant</u>								
8	Land	350.10	23,882	0	0	23,882	0	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0	1,126,772
12	Wells Equipment	352.02	1,072,970	0	(2,282)	1,070,688	0	0	1,070,688
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	0	67,498
15	Lines	353.00	387,525	0	0	387,525	0	0	387,525
16	Compressor Station Equipment	354.00	947,638	0	(683)	946,954	0	0	946,954
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0	104,477
18	<u>Distribution Plant</u>								
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0	21,944
20	Land, Other Distribution System	374.20	3,361,033	0	0	3,361,033	0	0	3,361,033
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0	95,361
22	Land Rights, City Other Distribution System	374.40	8,148,355	180,883	0	8,329,237	0	0	8,329,237
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0	13
24	Rights of Way	374.50	3,233,314	0	0	3,233,314	0	0	3,233,314
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0	4,012
27	Structures, Regulating	375.40	6,496,995	12,435	0	6,509,430	0	0	6,509,430
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	0	86,084
29	Structures, Other Distribution System	375.70	49,817,735	161,955	(8,853)	49,970,837	9,019	(5,482)	49,974,375
30	Structures, Other Distribution System, Leased	375.71	5,593,262	58,253	(2,500)	5,649,015	734,476	0	6,383,491
31	Structures, Communication	375.80	16,515	0	0	16,515	0	0	16,515
32	Mains	376.00	2,742,038,630	51,807,427	(2,204,520)	2,791,641,537.35	27,412,258	(1,874,226)	2,817,179,570
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0	23,515,481
34	Bare Steel	376.30	60,164,271	6,096	(144,955)	60,025,413	19	(32,169)	59,993,263
35	Cast Iron	376.80	148,787	0	(89)	148,698	0	0	148,698
36	Measuring & Regulating Equipment General	378.10	1,442,966	0	0	1,442,966	0	0	1,442,966
37	Measuring & Regulating Equipment Regulating	378.20	147,205,634	638,852	(5,509)	147,838,978	313,715	(6,813)	148,145,880
38	Measuring & Regulating Equipment Local Gas	378.30	406,301	0	0	406,301	0	(112)	406,189
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(903)	0	0	(903)	0	0	(903)
41	Services	380.00	837,533,879	6,602,207	(1,084,525)	843,051,561	5,338,593	(1,183,926)	847,206,228
42	Meters	381.00	46,480,773	84,073	(65,738)	46,499,108	89,044	(40,980)	46,547,173
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	0	0	24,668,228
44	Meter Installations	382.00	47,124,441	220,067	(22,780)	47,321,729	4,919,917	(30,605)	52,211,040
45	House Regulators	383.00	18,684,974	95,429	(4,291)	18,776,113	110,210	(4,382)	18,881,941
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	6,906,381	638,469	0	7,544,850	9,341	(10,661)	7,543,530
48	Industrial M&R Equipment. Large Volume	385.10	993,577	0	(1,730)	991,848	0	(102)	991,746
49	Other Equipment	387.10	19,450	0	0	19,450	0	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0	119,609
52	Other Equipment, Other Communications	387.44	563,356	0	0	563,356	0	0	563,356
53	Other Equipment, Telemetering	387.45	15,727,007	907,598	(79,855)	16,554,751	378,685	(27,173)	16,906,263
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0	2,201,372
56	<u>General Plant</u>								
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	3,698,665	19,510	0	3,718,176	1,057,167	(10,222)	4,765,121
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	557,560	0	0	557,560	8,002	0	565,562
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0	0
62	Transportation Equipment, Trailers > \$1,000	392.20	14,787	0	0	14,787	0	0	14,787
63	Transportation Equipment, Trailers \$1,000 or <	392.21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	387,740	0	0	387,740	0	0	387,740
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	21,080,215	44,736	(9,858)	21,115,093	66,353	(33,794)	21,147,652
70	Tools, High Pressure Stopping	394.31	66,413	0	0	66,413	0	0	66,413
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	770,403	0	0	770,403	0	0	770,403
78	Miscellaneous Equipment	398.00	1,116,293	17,349	0	1,133,641	15,000	0	1,148,641
79	Total Gas Plant in Service		4,152,531,638	62,793,114	(4,110,687)	4,211,214,065	41,765,417	(3,398,588)	4,249,580,894

**Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated For Actuals Through December 31, 2024
R-2024-3046519**

Line No.	Account No.	Beginning Balance 8/31/2024	Additions	Retirements	Balance as of 9/30/2024 (5 = 2+3+4)	Additions	Retirements	Balance as of 10/31/2024 (8)=(5+6+7)
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
		\$	\$	\$	\$	\$	\$	\$
1	<u>Intangible Plant</u>							
2	Organization Costs	301.00	100,099	0	0	100,099	0	100,099
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	26,216
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303.30	47,742,229	137,183	(658,676)	47,220,736	935,150	48,022,187
6	Cloud Software	303.99	8,794,485	16,670	0	8,811,155	970,586	9,781,741
7	<u>Underground Storage Plant</u>							
8	Land	350.10	23,882	0	0	23,882	0	23,882
9	Rights of Way	350.20	1,932	0	0	1,932	0	1,932
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	3,294,840
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	1,126,772
12	Wells Equipment	352.02	1,070,688	0	0	1,070,688	0	1,072,322
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	139,442
14	Other Leases	352.12	67,498	0	0	67,498	0	67,498
15	Lines	353.00	387,525	0	0	387,525	0	387,525
16	Compressor Station Equipment	354.00	946,954	0	0	946,954	0	947,638
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	104,477
18	<u>Distribution Plant</u>							
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	21,944
20	Land, Other Distribution System	374.20	3,361,033	0	0	3,361,033	0	3,361,033
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	95,361
22	Land Rights, City Other Distribution System	374.40	8,329,237	476	0	8,329,713	62,195	8,391,908
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	13
24	Rights of Way	374.50	3,233,314	0	0	3,233,314	0	3,233,314
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	7,026
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	4,012
27	Structures, Regulating	375.40	6,509,430	0	0	6,509,430	0	6,509,430
28	Structures, Distribution Industrial M&R	375.60	86,084	0	0	86,084	0	85,565
29	Structures, Other Distribution System	375.70	49,974,375	1,200	0	49,974,375	94,750	50,068,380
30	Structures, Other Distribution System, Leased	375.71	6,383,491	(1,200)	0	6,382,291	0	6,382,291
31	Structures, Communication	375.80	16,515	0	0	16,515	23,265,736	23,104,083
32	Mains	376.00	2,817,179,570	17,779,251	(622,444)	2,834,336,377	0	2,834,336,377
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	23,515,481
34	Bare Steel	376.30	59,993,263	0	(93,719)	59,899,543	0	59,885,500
35	Cast Iron	376.80	148,698	0	0	148,698	0	148,698
36	Measuring & Regulating Equipment General	378.10	1,442,966	0	0	1,442,966	0	1,442,966
37	Measuring & Regulating Equipment Regulating	378.20	148,145,880	32,354	(39,363)	148,138,871	(17,175)	148,081,825
38	Measuring & Regulating Equipment Local Gas	378.30	406,189	0	0	406,189	0	406,189
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	120,061
40	Measuring & Regulating Equipment Exchange Gas	379.11	(903)	0	0	(903)	0	(903)
41	Services	380.00	847,206,228	5,643,588	(1,128,291)	851,721,524	5,794,213	856,588,135
42	Meters	381.00	46,547,173	236,372	(51,800)	46,731,745	(1,258,139)	45,410,465
43	Auto Meter Reading Devices	381.10	24,668,228	0	0	24,668,228	1,612,169	26,280,397
44	Meter Installations	382.00	52,211,040	176,638	(27,673)	52,360,005	149,868	52,481,175
45	House Regulators	383.00	18,881,941	95,949	(4,731)	18,973,159	145,278	19,114,400
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	3,484,788
47	Industrial M&R Equipment. Station Equipment	385.00	7,543,530	144,527	(59,376)	7,628,680	1,620	7,614,582
48	Industrial M&R Equipment. Large Volume	385.10	991,746	0	(457)	991,288	0	990,522
49	Other Equipment	387.10	19,450	0	0	19,450	0	19,450
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	117,248
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	119,609
52	Other Equipment, Other Communications	387.44	563,356	0	0	563,356	0	563,356
53	Other Equipment, Telemetering	387.45	16,906,263	12,074	0	16,918,336	339,593	17,085,924
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	259,436
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	2,201,372
56	<u>General Plant</u>							
57	Structures, Communications	390.10	49,821	0	0	49,821	0	49,821
58	Office Furniture & Equipment, Unspecified	391.10	4,765,121	0	0	4,765,121	2,264,652	7,029,773
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	91,304
60	Office Furniture & Equipment, Information Systems	391.12	565,562	0	(10,860)	554,702	0	554,702
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0
62	Transportation Equipment, Trailers > \$1,000	392.20	14,787	0	0	14,787	0	14,787
63	Transportation Equipment, Trailers \$1,000 or <	392.21	10,830	0	0	10,830	0	10,830
64	Stores Equipment	393.00	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	387,740	0	0	387,740	0	387,740
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	18,450
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	21,147,652	105,609	(23,769)	21,229,492	141,888	21,334,951
70	Tools, High Pressure Stopping	394.31	66,413	0	0	66,413	0	66,413
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	264,921
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	948,698
73	Communication Equipment	397.00	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	770,403	0	0	770,403	0	769,399
78	Miscellaneous Equipment	398.00	1,148,641	9,881	(11,312)	1,147,211	0	1,147,211
79	Total Gas Plant in Service		4,249,580,894	24,389,371	(2,732,472)	4,271,237,793	34,502,384	4,304,125,446

**Columbia Gas of Pennsylvania, Inc.
Gas Plant in Service by Gas Plant Account
Updated For Actuals Through December 31, 2024
R-2024-3046519**

Line	Account	Beginning			Balance			Balance
No.	Description	No.	10/31/2024	Additions	Retirements	11/30/2024	Additions	Retirements
		(1)	(2)	(3)	(4)	(5 = 2+3+4)	(6)	(7)
			\$	\$	\$	\$	\$	\$
1	<u>Intangible Plant</u>							
2	Organization Costs	301.00	100,099	0	0	100,099	0	0
3	Franchises/Consent, Perpetual	302.10	26,216	0	0	26,216	0	0
4	Intangible Plant, General	303.00	4,809,062	0	0	4,809,062	0	0
5	Intangible Plant, Miscellaneous Software	303.30	48,022,187	126,750	(1,048,325)	47,100,612	1,551,904	(575,231)
6	Cloud Software	303.99	9,781,741	281,798	0	10,063,539	375,001	0
7	<u>Underground Storage Plant</u>							
8	Land	350.10	23,882	0	0	23,882	0	0
9	Rights of Way	350.20	1,932	0	0	1,932	0	0
10	Compressor Station Structures	351.20	3,294,840	0	0	3,294,840	0	0
11	Wells Construction	352.01	1,126,772	0	0	1,126,772	0	0
12	Wells Equipment	352.02	1,072,322	0	0	1,072,322	0	0
13	Storage Leasehold and Rights	352.10	139,442	0	0	139,442	0	0
14	Other Leases	352.12	67,498	0	0	67,498	0	0
15	Lines	353.00	387,525	0	0	387,525	0	(1,728)
16	Compressor Station Equipment	354.00	947,638	0	0	947,638	0	0
17	Measuring & Regulating Equipment	355.00	104,477	0	0	104,477	0	0
18	<u>Distribution Plant</u>							
19	Land, City Gate/Main Line Industrial	374.10	21,944	0	0	21,944	0	0
20	Land, Other Distribution System	374.20	3,361,033	0	0	3,361,033	0	0
21	Land Rights, City Gate/Main Line	374.30	95,361	0	0	95,361	0	0
22	Land Rights, City Other Distribution System	374.40	8,391,908	546,279	0	8,938,187	1,742,540	0
23	Land Rights, City Other Distribution System, Loc	374.41	13	0	0	13	0	0
24	Rights of Way	374.50	3,233,314	0	0	3,233,314	0	0
25	Structures, City Gate Measurement & Regulating	375.20	7,026	0	0	7,026	0	0
26	Structures, General Meas & Reg Local Gas	375.31	4,012	0	0	4,012	0	0
27	Structures, Regulating	375.40	6,509,430	78,340	(30,443)	6,557,326	645,139	(8,204)
28	Structures, Distribution Industrial M&R	375.60	85,565	0	0	85,565	0	0
29	Structures, Other Distribution System	375.70	50,068,380	(108)	0	50,068,272	182,880	(143)
30	Structures, Other Distribution System, Leased	375.71	6,382,291	(111)	0	6,382,180	163,308	0
31	Structures, Communication	375.80	23,104,083	0	0	23,104,083	0	0
32	Mains	376.00	2,834,336,377	39,538,106	(4,272,231)	2,869,602,252	77,201,387	(8,577,120)
33	Mains - CSL Replacements	376.08	23,515,481	0	0	23,515,481	0	0
34	Bare Steel	376.30	59,885,500	0	(148,932)	59,736,568	0	(656,133)
35	Cast Iron	376.80	148,698	0	0	148,698	0	0
36	Measuring & Regulating Equipment General	378.10	1,442,966	0	0	1,442,966	0	(550)
37	Measuring & Regulating Equipment Regulating	378.20	148,081,825	329,070	(41,974)	148,368,922	9,141,982	(98,121)
38	Measuring & Regulating Equipment Local Gas	378.30	406,189	0	0	406,189	0	(371)
39	Measuring & Regulating Equipment City Gate	379.10	120,061	0	0	120,061	0	0
40	Measuring & Regulating Equipment Exchange Gas	379.11	(903)	0	0	(903)	0	0
41	Services	380.00	856,588,135	7,662,717	(1,516,163)	862,734,689	8,902,514	(1,623,316)
42	Meters	381.00	45,410,465	280,729	(73,838)	45,617,357	94,724	(1,558,076)
43	Auto Meter Reading Devices	381.10	26,280,397	9,617	0	26,290,014	29,984	0
44	Meter Installations	382.00	52,481,175	155,655	(28,931)	52,607,899	190,933	(26,334)
45	House Regulators	383.00	19,114,400	120,508	(3,902)	19,231,006	115,294	(3,300)
46	House Regulators Installations	384.00	3,484,788	0	0	3,484,788	0	0
47	Industrial M&R Equipment. Station Equipment	385.00	7,614,582	22,397	(5,155)	7,631,824	7,845	(26,386)
48	Industrial M&R Equipment. Large Volume	385.10	990,522	0	(813)	989,708	0	(5,577)
49	Other Equipment	387.10	19,450	0	0	19,450	0	0
50	Other Equipment, Odorization	387.20	117,248	0	0	117,248	0	0
51	Other Equipment, Radio	387.42	119,609	0	0	119,609	0	0
52	Other Equipment, Other Communications	387.44	563,356	0	(8,407)	554,949	0	0
53	Other Equipment, Telemetering	387.45	17,085,324	254,330	(97,777)	17,241,878	673,654	(37,003)
54	Other Equipment, Customer Information Service	387.46	259,436	0	0	259,436	0	0
55	GPS Pipe Locators	387.50	2,201,372	0	0	2,201,372	0	0
56	<u>General Plant</u>							
57	Structures, Communications	390.10	49,821	0	0	49,821	0	0
58	Office Furniture & Equipment, Unspecified	391.10	7,029,773	531	0	7,030,304	125,707	(12,929)
59	Office Furniture & Equipment, Data handling Equip	391.11	91,304	0	0	91,304	0	0
60	Office Furniture & Equipment, Information Systems	391.12	554,702	0	0	554,702	0	0
61	Office Furniture & Equipment, Air Condition Equip	391.20	0	0	0	0	0	0
62	Transportation Equipment, Trailers > \$1,000	392.20	14,787	0	0	14,787	0	0
63	Transportation Equipment, Trailers \$1,000 or <	392.21	10,830	0	0	10,830	0	0
64	Stores Equipment	393.00	0	0	0	0	0	0
65	Tools, Garage & Service Equipment	394.10	387,740	0	0	387,740	0	0
66	Tools, CNG Equipment, Stationary	394.11	18,450	0	0	18,450	0	0
67	Tools, CNG Equipment, Portable	394.12	0	0	0	0	0	0
68	Tools, Shop Equipment	394.20	0	0	0	0	0	0
69	Tools, Tools and Other	394.30	21,334,951	653,689	(34,707)	21,953,933	1,951,279	(127)
70	Tools, High Pressure Stopping	394.31	66,413	0	0	66,413	0	0
71	Laboratory Equipment Gas	395.00	264,921	0	0	264,921	0	0
72	Power Operated Equipment	396.00	948,698	0	0	948,698	0	0
73	Communication Equipment	397.00	0	0	0	0	0	0
74	Communication Equipment, Telephone	397.10	0	0	0	0	0	0
75	Communication Equipment, Radio	397.20	0	0	0	0	0	0
76	Communication Equipment, Other	397.40	0	0	0	0	0	0
77	Communication Equipment, Telemetering	397.50	769,399	0	0	769,399	0	0
78	Miscellaneous Equipment	398.00	1,147,211	(16,331)	0	1,130,880	65,213	0
79	Total Gas Plant in Service		<u>4,304,125,446</u>	<u>50,043,968</u>	<u>(7,311,597)</u>	<u>4,346,857,816</u>	<u>103,161,289</u>	<u>(13,210,647)</u>
								<u>4,436,808,458</u>

Columbia Gas of Pennsylvania, Inc.
Property, Plant & Equipment - Budget to Actual Comparison
2024 Rate Case at Docket R-2024-3046519

Ln. No.	Net Additions							
	Budget			Actuals		Month	Cumulative Spend	Over (Under) (8)=(7/3) (%)
	Month	Month	Cumulative	Month	Cumulative	Over (Under)	Over (Under)	
	(1)	(2)	(3)	(4)	(5)	Budget (6)=(4-2) (\$)	Budget (7)=(5-3) (\$)	
		(\$)	(\$)	(\$)	(\$)			
1	1/31/2024	26,099,675	26,099,675	8,545,461	8,545,461	(17,554,214)	(17,554,214)	-67.26%
2	2/29/2024	25,781,600	51,881,275	9,669,727	18,215,188	(16,111,873)	(33,666,088)	-64.89%
3	3/31/2024	23,145,632	75,026,907	15,358,328	33,573,516	(7,787,304)	(41,453,391)	-55.25%
4	4/30/2024	43,142,090	118,168,997	15,671,343	49,244,858	(27,470,747)	(68,924,139)	-58.33%
5	5/31/2024	53,379,853	171,548,850	25,106,589	74,351,447	(28,273,264)	(97,197,403)	-56.66%
6	6/30/2024	35,580,121	207,128,971	25,152,765	99,504,212	(10,427,356)	(107,624,758)	-51.96%
7	7/31/2024	26,418,877	233,547,848	58,682,427	158,186,640	32,263,550	(75,361,208)	-32.27%
8	8/31/2024	27,017,802	260,565,650	38,366,828	196,553,468	11,349,026	(64,012,182)	-24.57%
9	9/30/2024	25,576,683	286,142,333	21,656,899	218,210,367	(3,919,784)	(67,931,966)	-23.74%
10	10/31/2024	28,258,697	314,401,030	32,887,653	251,098,020	4,628,956	(63,303,009)	-20.13%
11	11/30/2024	22,927,664	337,328,693	42,732,370	293,830,391	19,804,707	(43,498,303)	-12.89%
12	12/31/2024	33,430,687	370,759,380	89,950,642	383,781,033	56,519,955	13,021,653	3.51%

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

DIRECT TESTIMONY OF
RIBEKA DANHIRES
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

I. Introduction

Q. Please state your name and business address.

A. My name is Ribeka Danhires, and my business address is 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

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

A. I am employed by Columbia Gas of Pennsylvania, Inc., (“Columbia” or “the Company”) as Manager, Rates & Regulatory Service.

Q. What are your responsibilities as Manager, Rates & Regulatory Service?

A. I am responsible for managing Columbia’s rates and regulatory activity before the Pennsylvania Public Utility Commission (“Commission”). This responsibility includes ensuring timely, accurate rate and regulatory filings with the Commission, as well as compliance with Columbia’s Rates and Rules for Furnishing Gas Service, known as Tariff Gas Pa. P.U.C. No. 9 (“Tariff”).

Q. Please describe your professional experience.

A. I hold a Bachelor of Arts degree in Accounting from the University of Pittsburgh and a Master’s of Business Administration degree from Seton Hill University. After graduating from college, I was employed by Duquesne Light Company (“DLC”) for ten years. I started in the Rates & Tariff Services Department as a Rates Analyst and concluded my time at DLC in the Regulatory Affairs Department as the Pennsylvania State Regulatory Coordinator. I joined Columbia in December 2015 as a Senior Rate

Analyst and moved into my current role as Manager, Rates & Regulatory Service in December 2018.

Q. Have you previously testified before this or any other utility Commission?

A. Yes. In Pennsylvania, I submitted direct testimony on behalf of Columbia in its 2021, 2022 and 2024 base rate cases, at Docket Nos. R-2021-3024296, R-2022-3031211 and R-2024-3046519, as the Tariff Witness. Additionally, I testified in several rate complaint hearings, most recently regarding the Company's Weather Normalization Adjustment ("WNA"), at Docket Nos. C-2023-3039555 and C-2023-3040138. I also provided direct testimony as the Tariff Witness in Columbia Gas of Maryland's ("CMD") 2018, 2021, and 2022 rate cases in Case Nos. 9480, 9664, and 9680, respectively, before the Maryland Public Service Commission. In addition, I submitted direct testimony and testified in support of CMD's 2016, 2017, 2018, 2019, and 2020 Purchased Gas Adjustment filings in Case Nos. 9510(j), 9510(k), 9510(l), 9510(m), and 9510(n), respectively. I also provided direct testimony in support of the settlement in CMD's 2019-2023 Strategic Infrastructure Development and Enhancement Plan ("STRIDE") in Case No. 9479 and direct testimony formally requesting approval for a new 5-year STRIDE Plan in Case Nos. 9709 and 9751.

Q. Please explain the purpose of your Direct Testimony in this proceeding.

A. My purpose in this proceeding is to present and sponsor Columbia's proposed tariff changes and identify the exhibits I am sponsoring. The details of the proposed tariff changes can be found in Exhibit 14, Schedule 2, Attachments B and C.

Q. What exhibits are you sponsoring?

A. I am sponsoring the following exhibits:

Exhibit No.:	Description:
Exhibit No. 10, Schedule 4	Company policy with respect to its relationship with potential customers.
Exhibit No. 14, Schedule 1	List of reports, data and statements provided to the Commission.
Exhibit No. 14, Schedule 2	Present and proposed tariff pages.
Exhibit No. 15, Schedule 1	Corporate history, list of counties and municipalities served, and total population in areas served.
Exhibit No. 15, Schedule 2	System map.
Exhibit No. 110, Schedule 4	Procedures developed to govern relationships between respondent and potential customers.
Exhibit No. 114, Schedule 1	List of reports, data and statements provided to the Commission and tariffs, both present and proposed.
Exhibit No. 115	Corporate history, system map, and affiliate relationships.

II. Summary of Tariff Changes

Q. Please provide a description of Columbia's proposed tariff changes.

1 A. There are substantive and non-substantive changes to the tariff that are proposed in
2 Supplement No. 392 in this case. The more prominent substantive changes to the
3 tariff that are proposed include: (1) revised base rates that reflect the proposed annual
4 increase to the revenue requirement; (2) an extension and expansion of the
5 Company's current residential energy efficiency programs to residential customers,
6 as well as a proposal to offer commercial programs to small commercial customers
7 through Rider EE – Energy Efficiency Rider ("Rider EE"); (3) proposed residential
8 and small commercial Rider EE rates to become effective January 1, 2026; (4)
9 modification to the Company's current Rider WNA – Weather Normalization
10 Adjustment ("Rider WNA") to permanently add this rider to the Company's tariff; (5)
11 inclusion of a new rate schedule, Economic Development Distribution Service
12 ("EDDS"), to allow service to large volume customers; and (6) implementation of a
13 new rate rider, Rider RNA – Revenue Normalization Adjustment ("Rider RNA") to
14 ensure full revenue stabilization. There are several additional substantive tariff
15 changes that include modifications to existing text within the tariff. All substantive
16 changes are reflected by a "(C)" in the right margin of the tariff pages. Along with the
17 substantive changes, there are several non-substantive changes, such as formatting,
18 that are included in tariff Supplement No. 392.

19 **Q. Please provide a list of all the tariff changes.**

20 A. Tariff pages 2 through 2a within Exhibit 14, Schedule 2, Attachments B and C,
21 present the List of Changes to the Tariff proposed in this case.

III. Substantive Tariff Changes

Q. Supplement No. 392 reflects revised base rates as shown on Page Nos. 16-18 and Page Nos. 20-21c. Please describe the rate changes.

A. There are eight pages that contain rate information. There are three “Rate Summary” pages and five other “Summary” pages.

Q. Please explain the changes on the “Rate Summary” pages.

A. Page Nos. 16-18 are the “Rate Summary” pages that contain the rate components and the total effective rate for each of the Company’s rate schedules. The changes to each rate schedule, by page, are described below.

Page No. 16 includes the rates for Residential Sales Service and Choice service (Rate Schedules RSS and RDS). These rate schedules reflect an increase to the Customer Charge, Distribution Charge and Pass-through Charge and a decrease to the Gas Supply Charge. Although the Company is proposing a new residential Rider EE rate, the current rate is shown on this page because it will remain in effect until December 31, 2025. The first year of new rates, for the proposed extension of the residential programs through Rider EE, will become effective January 1, 2026. In addition to revised rates, a new column was added to Page No. 16 for the proposed Rider RNA. Rider RNA rates are not shown as the Company is not proposing rates to go into effect until April 1, 2027.

Page No. 17 includes the rates for commercial and industrial accounts. Commercial and industrial accounts using less than or equal to 64,400 therms per

1 year normally fall into one of three rate schedules depending on their selected service.
2 Rate Small General Sales Service (“SGSS”) reflects the rates for customers purchasing
3 their gas supply from the Company, while Rate Small Commercial Distribution
4 (“SCD”) and Rate Small General Distribution Service (“SGDS”) are tariffed rate
5 schedules for the mandatory firm capacity Choice program and the Gas Distribution
6 Service program respectively, which are for customers choosing to purchase their gas
7 from a natural gas supplier. These rate schedules reflect an increase to the Customer
8 Charge and Distribution Charge and a decrease to the Gas Supply Charge. Two new
9 columns were added to this page for the two new proposed riders, Rider EE and Rider
10 RNA. While a new column was added for the proposed Rider EE for small
11 commercial customers, no rate is shown as the rate will not become effective until
12 January 1, 2026. Rider RNA rates are not shown, as the Company is not proposing
13 rates to go into effect until April 1, 2027.

14 Page No. 18 includes rates for commercial and industrial customers using
15 more than 64,400 therms per year. Rate Schedule Large General Sales Service
16 (“LGSS”) is for customers who purchase their gas supply from Columbia. Rate
17 Schedules Small Distribution Service (“SDS”) and Large Distribution Service (“LDS”)
18 are rates for customers purchasing gas from suppliers. These rate schedules reflect
19 an increase to the Customer Charge and Distribution Charge. Additionally, a new
20 column was added to this page for the proposed Rider RNA. Rider RNA rates are not
21 shown, as the Company is not proposing rates to go into effect until April 1, 2027.

1 There are no proposed changes to Rate Schedules Main Line Sales Service
2 ("MLSS") and Main Line Distribution Service ("MLDS"), and therefore, Page No. 19
3 is not included in this Supplement for filing.

4 **Q. Please explain the changes on the remaining "Summary" pages.**

5 A. There are five remaining "Summary" pages, Page Nos. 20 through 21c: Other Rates
6 Summary, Rider Summary, Gas Supply Charge Summary, Pass-through Charge
7 Summary and Price-to-Compare ("PTC") Summary. These summary pages are
8 described below.

9 The "Other Rates Summary," Page No. 20, reflects decreases to the PTCs for
10 both the Residential Gas Supply and Commercial Gas Supply, which is a direct result
11 of the decrease to the Merchant Function Charge ("Rider MFC") rates.

12 The "Rider Summary," Page No. 21, reflects an increase to the Rider Universal
13 Service Plan ("Rider USP") rate and decreases to the Rider MFC rates. This page also
14 includes two new riders: Rider EE applicable to small commercial customers and
15 Rider RNA applicable to residential customers, excluding those in the Company's
16 Customer Assistance Plan ("CAP"), and commercial and industrial customers. As
17 explained above, the small commercial Rider EE rate is shown as zero since the
18 Company is not proposing a rate effective date until January 1, 2026. As also
19 explained above, Rider RNA rates are not shown, as the Company is not proposing
20 rates to go into effect until April 1, 2027.

1 The “Gas Supply Summary”, Page No. 21a, reflects decreases to the Rider MFC
2 rates.

3 The residential rates (Rate Schedules RSS and RDS) included on the “Pass-
4 through Charge Summary,” Page No. 21b, have increased, which is a direct result of
5 the increase to the Rider USP rate.

6 Last, the “PTC Summary,” Page No. 21c, reflects decreases to both residential
7 and commercial classes, which is a direct result of the decreases to the Rider MFC
8 rates.

9 **Q. Where do the rate changes contained in your testimony originate?**

10 A. The rate changes affecting the Customer Charge and Distribution Charge for each
11 rate schedule can be found within Exhibit No. 103, Schedule No. 8, Pages 5 through
12 9, and are discussed in Company witness Kevin Johnson’s Direct Testimony,
13 (Columbia Statement No. 6). The rate change to Rider USP can be found on Page 5
14 within that same exhibit. The percentages for Rider MFC, as shown on tariff Page No.
15 161, have been updated to reflect proposed rates as identified in Exhibit MLB-1
16 attached to Company witness May Battig’s Direct Testimony (Columbia Statement
17 No. 3).

18 **Q. Other than base rate changes, please describe the other substantive**
19 **changes in Supplement No. 392.**

20 A. As stated above, there are several other substantive changes proposed, and each are
21 described in detail below:

Rider EE

Q: The Company's tariff includes modifications to Rider EE. Please explain.

A. Company witness Joseph A. Nunley (Statement No. 13), provides an overview of the Company's Three-Year Energy Efficiency Plan ("Phase II Plan") in his Direct Testimony. In the Phase II Plan, the Company proposes: (1) to continue the existing two residential energy efficiency programs and (2) launch a new third energy efficiency program for small commercial customers. Supplement No. 392 includes a new column on Page No. 17 for the proposal to offer commercial programs to Rate Schedules SGSS, SCD and SGDS. The Rider Summary, Page No. 21, now reflects an additional line to include the small commercial Rider EE rate and applicable rate schedules. In addition, Page Nos. 164 and 164a, the Company's Rider EE tariff provision, have been modified to include small commercial programs and cost recovery. The new Rider EE rate for residential customers (except CAP customers) and the proposed Rider EE rate for small commercial customers are proposed to become effective in coordination with the start of the new energy efficiency programs, and not with the implementation of new base rates. Company witness Johnson provides the calculation of the proposed rates to become effective January 1, 2026, attached to his Direct Testimony as Exhibit KLJ-7.

Rider WNA

Q. The Company's tariff includes a modification to Rider WNA. Please explain.

1 A. As discussed by Company witness John D. Taylor (Statement No. 17), the Company
2 proposes that the current Rider WNA mechanism become a permanent mechanism.
3 Supplement No. 392, Page Nos. 162 and 163, have been modified accordingly. This
4 Rider will continue to be applied to bills of residential customers on Rate Schedules
5 RSS, RDS and CAP for the heating season (November through May). The current 3%
6 deadband will remain in effect.

7 Rate Schedule EDDS

8 **Q. The Company's tariff includes a proposal for a new rate schedule, EDDS.**
9 **Please explain.**

10 A. The Company is seeking approval of a new rate schedule to allow the flexibility to
11 bring on new large volume customers as described by Company witness Nicole M.
12 Paloney (Statement No. 9). The tariff will treat these customers as non-jurisdictional
13 customers and provide the Company the opportunity to enter into individual
14 contracts with customers taking service under Rate Schedule EDDS. Rate Schedule
15 EDDS has been added to Supplement No. 392 in Page Nos. 124-124b.

16 Rider RNA

17 **Q. The Company's tariff includes a proposal for Rider RNA. Please explain.**

18 A. Company witness Taylor describes the Company's proposal to implement an RNA
19 mechanism, Rider RNA, to ensure the Company recovers its Commission-approved
20 revenue. Rider RNA has been added to the Supplement No. 392 as Page Nos. 145 and
21 145a. This Rider will be applicable to non-CAP residential customers as well as

commercial and industrial customers on the following rate schedules: SGSS, SCD, SGDS, LGSS, SDS and LDS. A column has been added to each of the applicable customer rate schedules on Page Nos. 16, 17 and 18, and lines have been added to the Rider Summary page, Page No. 21, for Rider RNA.

Q. Page Nos. 16-18 and Page No. 21 of the tariff designates a location for Rider RNA, however, a rate is not included. Please explain.

A. As indicated in the description of Rider RNA on pages 145 and 145a of the Tariff, the Company is not proposing to bill Rider RNA until April 1, 2027. Columbia has filed the proposed tariff with an effective date of May 19, 2025, and at that time, a rate for Rider RNA will not be billed. Therefore, it is appropriate that a Rider RNA rate is not specified in the tariff.

Additional Substantive Changes

Q. There are several text changes proposed for approval in Supplement No. 392. What pages contain text changes?

A. The tariff pages that include proposed changes to the current text are as follows: Page Nos. 27, 31, 38, 143, 146, 160, 161, 200a, 200b, 201, 226, 227a, 230, 231, 234, 237 and 239.

Q. Please explain the text changes to Page Nos. 27, 200a, 226, 234, 237 and 239.

A. Page Nos. 226 and 234 were modified to remove the option for Natural Gas Suppliers ("NGSS") to change their Annual Capacity Assignments. The Company's Aggregation

1 Agreement has since been updated to remove the capacity election, as there is only
2 one capacity assignment requirement. Therefore, the tariff has been updated to
3 reflect this change.

4 Page No. 234, along with pages 27, 200a, 237 and 239, include a name change
5 from Dominion Energy Transmission, Inc. to Eastern Gas Transmission and Storage,
6 Inc. These pages also include the removal of Columbia Gulf Transmission, LLC due
7 to the expiration of pipeline transportation contracts.

8 **Q. Please explain the text change to Page No. 31**

9 A. This page was modified to correct a minor grammatical error. The past tense was
10 removed from the word “requested” in Section 2.3.2. ‘Demonstrative of Firm Pipeline
11 Capacity.’

12 **Q. Please explain the text change to Page Nos. 38, 230 and 231.**

13 A. These pages were modified to add email as a method of communicating NGS
14 offerings to customers, as well as for the Company to communicate a customer’s
15 selection to an NGS.

16 **Q. Please explain the text change to Page No. 143.**

17 A. Text was removed from this page to eliminate the provision that the Company will
18 solicit Commission-licensed NGSs to provide the CAP gas supply service at a
19 discount, as the Company is no longer required to do this per the April 2024
20 Universal Service & Energy Conservation Plan (“USECP”) Order at Docket No. M-
21 2023-3039487.

1 **Q. Please explain the text changes to Page Nos. 146, 160 and 161.**

2 A. There are two changes proposed on Page No. 146. First, the Company added text to
3 the verbiage under the “Calculation of Rate” within Rider USP to include recovery of
4 Commission-mandated Universal Service Programs or low-income programs. This
5 addition is discussed by Company witness Deborah A. Davis in her Direct Testimony
6 (Statement No. 16). Second, the Company is removing text within that same section
7 of Page No. 146 related to obtaining a CAP gas supply aggregator. Text related to
8 NGSs providing natural gas to the CAP aggregation is also removed on Page Nos. 160
9 and 161. The Company is removing this language pursuant to the Commission’s April
10 2024 USECP Order at Docket No. M-2023-3039487.

11 **Q. Please explain the text change to Page Nos. 200b and 227a.**

12 A. Both pages were modified to correct an outdated Supplier website that NGSs use to
13 access customers’ historical usage and the Eligible Customer List (“ECL”). The
14 corrected website, as displayed on these pages, is NiSourceSuppliers.com.

15 **Q. Please explain the text change to Page No. 201.**

16 A. Section 3.2.1 under the “Application Process,” which applies to all General
17 Distribution Service customers, was modified to reflect the current process that is
18 used to calculate an adjustment for a customer’s current effective annual quantities.

19 **IV. Non-Substantive Tariff Changes**

20 **Q. Please explain the non-substantive tariff changes.**

1 A. The non-substantive changes are related to formatting. The headers on each tariff
2 page have been updated to reflect Supplement No. 392 and the sequence of each page
3 number has increased by one from the previously filed supplement number for each
4 individual page. The “Issued” date and the “Effective” date in the footer on each tariff
5 page now reflects “March 20, 2025” and “May 19, 2025,” respectively. The following
6 tariff pages, where modifications were made and discussed earlier in my testimony,
7 reflect changes in the footer to include the current Company President’s name: 27,
8 31, 38, 124, 143, 201, 226, 227a, 230, 231, 234, 237 and 239. Tariff Page Nos. 2 and
9 2a have been prepared to show the changes included in Supplement No. 392.
10 Additionally, the Table of Contents, Page No. 4, has been updated to include the
11 Company’s proposal for Rate Schedule EDDS and Rider RNA. Rate Schedule EDDS
12 has been incorporated into the tariff as Page No. 124, and continues through Page
13 No. 124b, that was previously Held for Future Use. Rider RNA has been incorporated
14 into the tariff as Page No. 145, and continues onto page 145a, that was previously
15 Held for Future Use. Page No. 144 remains Held for Future Use.

16 **Q. Does this complete your prepared Direct Testimony?**

17 A. Yes.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility
Commission

v.

Columbia Gas of Pennsylvania, Inc.

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Docket No. R-2025-3053499

DIRECT TESTIMONY OF
JOSEPH A. NUNLEY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

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1 **I. INTRODUCTION**

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

3 A. My name is Joseph A. Nunley, and I am a Partner at Green Energy Economics Group, Inc.
4 ("GEEG"), an energy consulting firm founded in 2005. My business address is 2209 N
5 2nd St, Harrisburg, PA 17110.

6 **Q. On whose behalf are you testifying?**

7 A. My testimony is submitted on behalf of Columbia Gas of Pennsylvania ("Columbia
8 Gas" or the "Company").

9 **Q. Please briefly describe your professional experience.**

10 A. I have been in the energy efficiency industry since 2007. I started in the industry as
11 the Owner and President of a Harrisburg, Pennsylvania based firm that provided
12 energy audits and weatherization services for Utility and Department of Energy
13 Low-Income Programs. I then spent five years working for both natural gas and
14 electric utilities on both East and West Coasts, where I was responsible for the
15 management and development of large trade ally networks and for the design,
16 development, and management of Demand Side Management portfolios. Following
17 my utility career, and prior to joining Green Energy Economics Group, Inc., I was
18 the Vice President of Program Services for an energy efficiency services and software
19 company. In this role, I was responsible for Program Implementation Services for
20 Residential, Commercial, and Energy Codes Programs for over 17 state and utility
21 clients throughout the Northeast and Midwest. Most relevant to this proceeding,
22 and since joining Green Energy Economics Group, I have been advising UGI

1 Utilities, Inc. – Gas Division (“UGI Gas”) on its Energy Efficiency and Conservation
2 Plan and Philadelphia Gas Works (“PGW”) on its energy efficiency activities. I also
3 advised the Massachusetts Office of the Attorney General, Office of Ratepayer
4 Advocacy on the recent statewide utility three-year plan filing. My full resume is
5 attached as Exhibit JAN-1.

6 **Q. Have you previously testified before this or any other regulatory agency?**

7 A. Yes. I have previously provided testimony to the Massachusetts Department of
8 Public Utilities, as listed in Exhibit JAN-1.

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

10 A. My testimony will address the achievements of the Company’s current Non-Low-
11 Income Energy Efficiency Pilot Phase (“Pilot”), as well as the proposed Phase II
12 Three-Year Energy Efficiency Plan (“Phase II Plan”), which the Company is
13 proposing to make a consistent offering of energy efficiency programs following the
14 success of the programs that are offered under the current Pilot.

15 **Q. Please summarize your testimony.**

16 A. I will describe the background and the performance of the Pilot and provide an
17 overview of the proposed Phase II Plan and its development. I will then discuss the
18 Phase II Plan’s projected cost, savings, and cost effectiveness under the Total
19 Resource Cost (“TRC”) test. Finally, I will provide a summary of each program
20 followed my recommendations and conclusions.

21 **Q. Are you sponsoring any exhibits in this proceeding?**

22 A. Yes, I am sponsoring the following exhibits, which are attached to this testimony:

- 23 • Exhibit JAN-1 – Resume of Joseph A. Nunley

- Exhibit JAN-2 – Phase II Three-Year Energy Efficiency Plan
- Exhibit JAN-3 – Columbia Gas Technical Reference Manual

II. PHASE I ENERGY EFFICIENCY PILOT PROGRAM

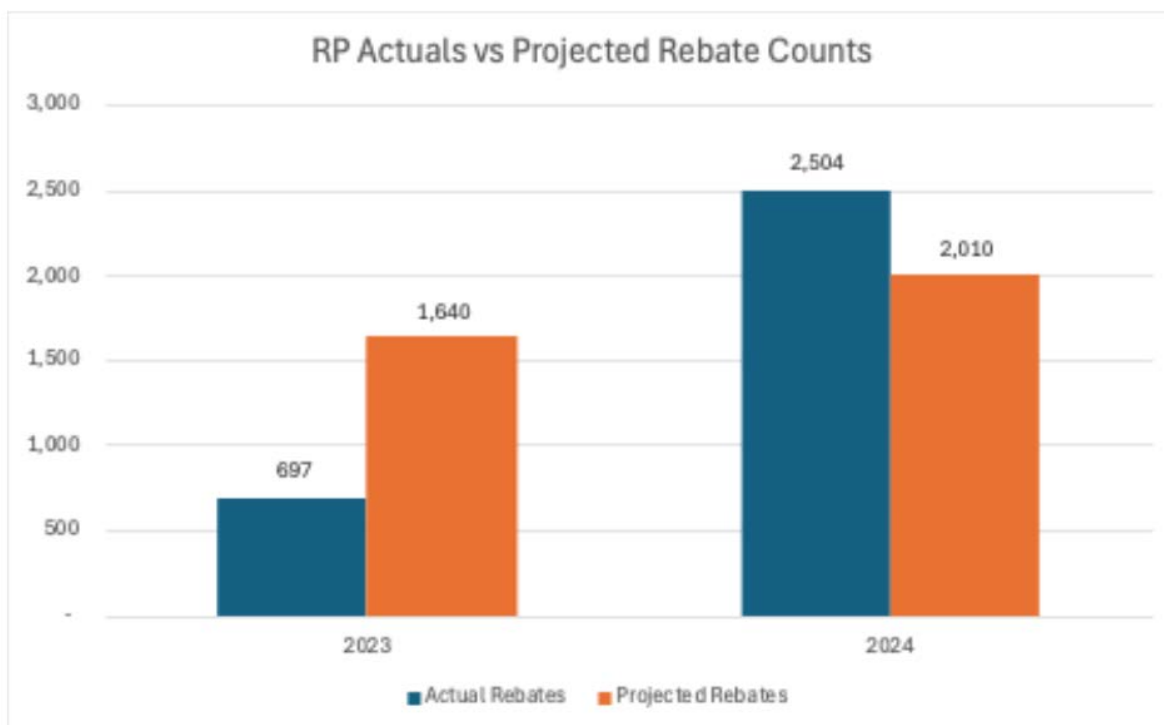
Q. Does Columbia Gas currently operate an Energy Efficiency Pilot Program?

A. Yes. The 2023-2025 Residential Energy Efficiency Pilot Program was originally approved as part of the Company's 2022 Rate Case at Docket No. R-2022-3031211, with a budget of \$4 million for the years 2023 to 2025. The Pilot was updated as part of the Company's 2024 Rate Case at Docket No. R-2024-3048418 to shift funding between programs to support additional prescriptive rebate measures. The updated Pilot was approved, with the budget remaining \$4 million for the years 2023 to 2025. The Pilot projects savings to the Company's residential customers of 1.23 million Dth of natural gas over the lifetime of the measures installed. From a total resource perspective, the Pilot is projected to provide a present value of net benefits of \$9.4 million (in 2022 dollars), with a Total Resource Cost test benefit-cost ratio ("BCR") of 2.85, more than twice the value of every dollar invested. Additionally, the Pilot is projected to avoid the emission of CO2 equivalent to over 2,896 cars being removed from the road over the lifetime of installed measures.

The Pilot has two programs; the Residential Prescriptive ("RP") Program, which provides incentives for high-efficiency natural gas fired equipment, and the Online Audit Kit ("OAK") Program, which provides customers with a customized online audit that then allows them to receive a space heating and/or water heating

1 kit at no cost. These Pilot Programs launched on August 1, 2023, and the Company
2 filed its first Annual Report in April 2024. Table 1 below summarizes the 2023 actual
3 rebates compared to the preliminary 2024 rebates for the RP program.

4 **Table 1**
5 **RP Actuals vs Projected Rebate Counts**



18 **Q. Have the programs offered under the Pilot been successful to date?**

19 A. Yes. The success of the OAK Program performance was the driver for the Company's
20 need to file an updated plan in 2024. In the first five months of program operation
21 (2023 program year) customers received 2,455 water savings kits and 1,339 space
22 heat savings kits (total of 3,794 kits). This represents 522% and 172% of the initially
23 filed 2023 program year goals, respectively. In 2024, the program was not marketed

to customers but continued to operate as the 2024 plan update of shifting unspent first year RP funds was awaiting approval. The preliminary program performance data show that even with the program not being marketed in the 2024 program year, customers still received 2,725 water savings kits and 262 space heat savings kits (total of 2,987 kits). This participation is expected to exceed 2023 program year levels in 2025 when marketing activities are restarted. The 2024 data have not been fully verified. The Company plans on submitting the fully verified 2024 data as part of its Annual Report filing in April 2025. Table 2 table below shows OAK program participation in total kits versus projected total kits for 2023 and the preliminary participation for 2024.

Table 2
OAK Program Kit Participation
2023 and Preliminary 2024

	2023	2024 (Preliminary)
Actual Kits	3,794	2,987
Projected Kits	1,250	7,550

The RP Program had a slower, but steady, ramp-up in customer participation, with rebates going to 697 measures. This represented slightly less than half of the projected measures for the 2023 program year as shown in the Table 3 below.

Table 3
Residential Prescriptive Rebates
2023 Projected vs. Actual

Measure	2023 Original EE Plan Projections	2023 Actual Rebates	%
Furnace	520	237	46%
Boiler	20	19	95%
Combi-boiler	80	33	41%
Smart Thermostat	900	345	38%
Tankless Water Heater	120	63	53%
Total	1,640	697	43%

It is important to note that this success was achieved with the programs operating for only five months of the year. In 2024, the preliminary program performance data show that the program has exceeded projections and has reached a steady state of high participation levels. The 2024 data will be submitted as part of its Annual Report filing in April 2025. The table below shows the preliminary 2024 program performance exceeding the performance projections in the approved 2024 updated plan filing. Table 4 below shows the positive performance trend in RP program performance from program launch in 2023 to 2024.

Table 4
Residential Prescriptive Rebates
2024 Projected vs. Preliminary Actual

Measure	2024 Updated EE Plan Projections	2024 Preliminary Actual Rebates	%
Furnace	500	1064	213%
Boiler	30	53	177%
Combi-boiler	60	72	120%
Smart Thermostat	1300	1109	85%
Tankless Water Heater	120	206	172%
Total	2,010	2,504	125%

While the 2024 data is preliminary, the program has successfully ramped up to exceed the Company's projections. In April 2024, the Company filed an Annual Report on 2023 program performance which showed TRC net benefits of \$1.8 million in just five months of program operation for the participating residential Columbia Gas customers. Given this early reported success, coupled with the positive upward participation trend shown in the RP program 2024 preliminary data, the Company developed the Plan to transition the existing residential Pilot program into a Phase II Three-Year Energy Efficiency Plan with the expectation of developing energy efficiency Phase updates on an ongoing basis. Furthermore, the success seen for the Company's residential customers led the Company to develop an additional energy efficiency offering to small commercial customers in Phase II. The proposed enhancements of benefits to Columbia Gas residential and small commercial customers are discussed in the next section of this testimony.

III. Phase II Plan

Q. Would you please describe the Phase II Three-Year Energy Efficiency Plan?

A. The Company is proposing to continue the existing two energy efficiency programs and launch a new third energy efficiency program over three years starting in January of 2026 based on the success from the 2023-2025 Pilot. These programs are designed to help the Company's residential and small commercial customers reduce their energy consumption, improve efficiency, and conserve resources. The Phase II Plan is projected to provide lifetime savings of 2.7 million dekatherms ("Dths") of natural gas at an implementation cost of \$7.9 million over three years.

Q. Are there any changes from the Pilot included in the Phase II Plan?

A. Yes. There are two changes the Company is proposing in the Phase II Plan. First, the Company is proposing to expand the measure offerings in the Residential Prescriptive ("RP") program to provide customers with more natural gas saving opportunities. These additional rebate offerings include boiler reset controls, efficient fireplace inserts, and single packaged vertical units. Second, the Company is proposing the addition of a Small Commercial ("SC") program. This program will provide natural gas saving opportunities through equipment rebates to small commercial customers by providing rebates for installing energy efficient equipment for heating, water heating, steam process, commercial cooking and dishwashing, and controls, as well as rebates for making improvements to the building shell through insulation and air sealing.

Q. Will the Plan, if implemented, benefit the Company's customers?

A. Yes, it will. The Company is proposing an investment that will return a present value of TRC net benefits of \$17.1 million, in 2025 dollars, with a TRC benefit-cost ratio ("BCR") of 2.49. Not only will the Phase II Plan provide significant energy savings and economic benefits for customers, it will also help customers increase the comfort of their homes, businesses, and reduce the emission of greenhouse gases. Reduced spending on energy also shifts spending to other parts of the economy which can have both an economic multiplier effect and help with regional job creation.

Q. How was the Plan developed?

A. As described in Section 1.2 of Exhibit JAN-2, the Phase II Plan was developed to help the Company's residential and small commercial customers use natural gas more efficiently. Two programs, the RP program and the OAK Program are a continuation of the current programs being run in the current Pilot. One new program, the SC program, was identified and developed to address the usage of natural gas in small commercial buildings.

The RP Program will continue to function in the same way that it has been operating since the Pilot was launched in August of 2023. In the Phase II Plan, three new rebate offerings are being added to the RP Program to provide customers with more opportunities to conserve natural gas. Those updates will be discussed in more detail later in this testimony. The second program, the OAK Program, will continue to function in the same way that it has been operating since the Phase I Plan was launched in August of 2023. The third program is the newly added SC Program. This program is designed to provide small commercial customers with opportunities to

1 save natural gas by providing rebates for installing energy efficient equipment for
2 heating, water heating, steam process, commercial cooking and dishwashing, and
3 controls, as well as rebates for making improvements to the building shell through
4 insulation and air sealing.

5 For the existing measures in the RP Program and the continuation of the OAK
6 Program, Pilot program participation data and trends were analyzed to project
7 participation and costs for the Phase II Plan.

8 For the newly added SC Program and the three additional measure offerings
9 in RP, various market characteristics were gathered for the Company's territory,
10 including avoided costs for natural gas and electricity, demographic, building stock,
11 and equipment market characteristics. Next, measures were characterized and
12 screened for cost effectiveness using the TRC test. Incentive levels were established
13 for these measures and projects, generally set to be in-line with the other programs
14 in Pennsylvania. The cost-effective measures and projects were then used to
15 calculate savings and maximum participation levels. Programs were staged to
16 account for the ramp-up required for new programs. Finally, administrative budgets
17 were developed to address fixed and variable costs associated with each program and
18 the portfolio.

19 **Q. How does the proposed Phase II Plan address low-income customers?**

20 A. Low-income customers, except for CAP customers, would be eligible to participate
21 in any of these residential programs, but the Phase II Plan does not specifically
22 include participation assumptions for this market. The OAK program does provide
23 a free online audit and will mail targeted low-cost energy saving kits to customers at

1 no cost. However, the majority of services offered by the Company for assisting low-
2 income customers with their energy bills are still through existing pathways, as
3 described by company witness Paloney in Columbia Statement No. 9 and company
4 witness Davis in Columbia Statement No. 16.

5 With the addition of Insulation and Air Sealing measures to the RP Program
6 that started in January 2025, the Company is developing coordination efforts with
7 the existing Columbia Gas Audits and Rebates Program, which serves customers up
8 to 250% of the Federal Poverty Income Limits who are not eligible for weatherization
9 measures through the Company's Low Income Usage Reduction Program
10 ("LIURP"). Currently, the Audits and Rebates Program offers customers a budget of
11 up to \$3,600 to perform heating and/or weatherization work on their homes based
12 on the LIURP measure priority list. Customers can have work done beyond the
13 \$3,600 budget but are then responsible to pay for the remaining balance. By
14 coordinating between programs, the RP Program incentives can be offered to Audits
15 and Rebate Program customers and expand the available budget per home.

16 **Q. Has Columbia Gas provided detailed implementation plans for each of**
17 **the proposed programs?**

18 A. Yes, Section 2 of Exhibit JAN-2 provides a detailed plan for each of the three
19 programs in the Phase II Plan, including annual budgets by cost category, savings,
20 and participation projections. There is also information on program delivery,
21 incentive design, target markets, marketing, as well as evaluation, measurement,
22 and verification details.

23 **Q. How much natural gas will Columbia Gas's customers save that**

participate in the Phase II Plan?

A. The programs are projected to save 160 thousand incremental annual Dths of natural gas and 2.7 million Dths over the lifetime of the measures installed. The following table shows the incremental and lifetime natural gas savings by program and are Tables 5 and 6 in Exhibit JAN-2.

Table 5

Incremental Natural Gas Savings (Dth) by Program

Program	2026	2027	2028	2026 - 2028
Residential Prescriptive Program	27,904	29,988	31,616	89,507
Online Audit Kit Program	10,914	12,607	14,299	37,820
Small Commercial Program	7,889	11,586	13,123	32,598
Total	46,707	54,180	59,038	159,925

Table 6

Lifetime Natural Gas Savings (Dth) by Program

Program	2026	2027	2028	2026 - 2028
Residential Prescriptive Program	535,834	576,820	606,084	1,718,739
Online Audit Kit Program	124,541	143,835	163,130	431,506
Small Commercial Program	151,033	188,733	204,113	543,880
Total	811,409	909,389	973,327	2,694,126

Q. What additional benefits are projected to occur from the Phase II Plan?

A. The Phase II Plan is projected to save 7,629 MWh of electricity and 508 million gallons of water over the lifetime of the measures installed. Additionally, the emission reduction of over 164,575 short tons of CO₂ is expected to occur from program activity, which is equivalent to removing over 6,286 cars from the road permanently. Section 1.4 of Exhibit JAN-2 contains additional details on savings projected for the plan.

Q. How much additional employment do you estimate that the Phase II Plan will generate?

A. The Plan is projected to generate between 81 and 162 net additional new jobs over the lifetime of the efficiency measures installed. The majority of these jobs will stay close to where savings occurred due to: (1) most of the job creation being a product of the economic “multiplier” effect through the cycle of re-spending energy savings; and (2) the shift away from spending in the less-labor intensive energy sector towards more job-intensive sectors such as food service and production, as explained in Section 1.4.4 of Exhibit JAN-2

Q. How much will it cost to achieve these results?

A. The total portfolio is projected to cost \$7.9 million over three years, or an average of \$2.6 million per year. The following table provides annual spending by program and is Table 6 of Exhibit JAN-2.

Table 7
Annual Spending by Program

Projected Costs (Nominal)	2026	2027	2028	2026 - 2028
Residential Prescriptive Program	\$1,190,625	\$1,282,950	\$1,285,250	\$3,758,825
Online Audit Kit Program	\$509,700	\$548,300	\$636,900	\$1,694,900
Small Commercial Program	\$431,538	\$487,433	\$594,883	\$1,513,854
Portfolio Wide Costs	\$335,000	\$289,000	\$293,000	\$917,000
Total	\$2,466,863	\$2,607,683	\$2,810,033	\$7,884,579

The following table breaks out the total spending at the portfolio level by budget category and year and is Table 2 in Exhibit JAN-2.

Table 8

Portfolio Level Total Spending by Budget Category

Category	2026	2027	2028	2026 - 2028
Customer Incentives	\$1,256,013	\$1,462,083	\$1,585,983	\$4,304,079
Administration	\$940,650	\$868,025	\$908,950	\$2,717,625
Marketing	\$173,950	\$135,075	\$140,850	\$449,875
Inspections	\$71,250	\$82,500	\$89,250	\$243,000
Evaluation	\$25,000	\$60,000	\$85,000	\$170,000
Total	\$2,466,863	\$2,607,683	\$2,810,033	\$7,884,579

Q. How will these costs be allocated to customers?

A. The programs are designed to target residential and small commercial customers. Projected first year spending from the RP and OAK programs will be recovered from the residential rate class and projected first year spending from the SC program will be recovered from the eligible small commercial rate classes. The costs associated with Portfolio-Wide expenses are allocated between residential and small commercial rate classes based on the percentage of total incentives, projected to be 79% for residential and 21% for small commercial in the first year. Following the first-year costs will be recovered based on actual program costs as a result of the participation by rate class through rate reconciliation.

Q. Is Columbia Gas proposing annual budget caps for individual programs?

A. No. The proposal is an investment over three years of approximately \$2.6 million dollars per year. Although the previously described budget levels represent anticipated funding levels, the utility should be allowed to move budget dollars between years and programs depending on market conditions and adoption rates. The total three-year budget is capped at the projected amount and the Plan still

needs to be cost effective at a portfolio level.

Q. Why is this flexibility important?

A. The ability to allocate funding effectively is crucial for a portfolio administrator. The ability to adjust budgets ensures that unspent funds from one program can be used to address higher demand in other programs and helps provide continuity for customers, contractors, and suppliers. This flexibility must also extend to program design and implementation, such as increasing or decreasing incentives based on market conditions. The Company would file for approval of a revised Plan if a program were added or removed, additional funds over and beyond the three-year cap were required, or material changes were expected for portfolio-level cost-effectiveness projections.

Q. How did you assess the economic benefits and costs of the Plan?

A. The TRC Test was used to evaluate the economic impacts of the Plan, based on the Act 129 TRC Test with modifications used in other approved voluntary gas programs in Pennsylvania, such as the plans from PGW and UGI Gas.

Q. What avoided costs values were used to develop the Plan?

A. As described in Section 1.5.2 of Exhibit JAN-2, the avoided cost of natural gas used updated the Phase I Plan's projection assumptions with NYMEX futures prices from January 17, 2025, and the latest US Energy Information Administration's Annual Energy Outlook forecast.

 Avoided costs for electricity and peak demand were based on values from the Act 129 Phase IV filings from the electric distribution companies. These values were translated to an annual kilowatt-hour and peak demand kilowatt value and weighted

1 by their overlap with The Company's service territory. Avoided cost for water came
2 from the Act 129 Phase IV TRC Test Order.

3 **Q. What are the lifetime TRC benefits and costs projected for the Plan?**

4 A. Under the TRC test, the Plan is projected to provide a present value of benefits in
5 2025 dollars of \$28.6 million with a corresponding cost of \$11.5 million. This comes
6 out to \$17.1 million in net benefits from the proposed plan with an overall BCR of
7 2.49. In addition, the RP, OAK, and SC programs are cost-effective on their own.

8 **Q. Will these net benefits stimulate economic activity?**

9 A. Yes. The present worth of TRC net benefits represents a long-term injection of
10 wealth into the economy. For residential customers, the reduction in the total costs
11 of gas service translates to after-tax disposable income, which can be saved or spent.
12 For small commercial customers, the reduction in the total costs of gas service
13 translates to increased profit margin, which can be utilized for business growth,
14 increased wages, and/or job creation. Moreover, the amount of additional economic
15 activity stimulated by the efficiency investment will end up being several times the
16 net benefits due to re-spending within the local, state, and regional economies.
17 While there is doubtless some "leakage" as some spending takes place outside
18 Pennsylvania, the majority of the economic benefits stay at the state and local levels.

19 This economic activity generated by the net economic benefits of efficiency
20 investment is in addition to the economic activity generated directly by expenditures
21 on the part of both The Company and program participants to install the efficiency
22 measures.

23 **Q. When does Columbia Gas anticipate programs will be available to**

1 **customers?**

2 A. The continuation of the existing RP and OAK programs will be available to
3 customers starting January 1, 2026, pending the timely approval of the Phase II
4 Plan. The Company anticipates that the newly developed SC program will be
5 available to customers approximately six months after approval of the Plan. This
6 means that the small commercial program is projected to launch in the first Quarter
7 of 2026. This will give the Company time to finalize program design details, hire
8 vendors to run the programs, and organize and implement any initial marketing
9 materials and outreach.

10 **Q. Please describe any proposed changes to the RP Program included in the**
11 **Phase II Plan.**

12 A. The RP Program aims to reduce lost opportunities for efficiency improvements
13 during the turnover of natural gas space heating and water heating equipment. The
14 program is expected to cost \$3.8 million in nominal dollars over three years and save
15 1.72 million Dth of natural gas over the lifetime of measures installed. The program
16 is projected to provide present value TRC net benefits of \$8.6 million with a BCR of
17 2.32. The program will also save 6,690 MWh of electricity and approximately 107
18 thousand tons of CO₂ over the lifetime of the installed measures, which is equivalent
19 to permanently removing over 4,074 cars from the road.

20 The existing Pilot RP program will continue into Phase II by providing
21 incentives for furnaces, boilers, combination space and water heating boilers
22 (“combi boilers”), tankless water heaters, WIFI-enabled thermostats, natural gas
23 heat pumps, and insulation and air sealing. The program uses ENERGY STAR®

1 criteria as a minimum efficiency level, when available. Phase II of the RP program
2 will provide customers additional opportunities to save natural gas by providing
3 incentives for boiler reset controls, fireplace inserts, and single packaged vertical
4 units. A full list of the measures along with minimum efficiency levels and proposed
5 incentives can be found in the “Financial Incentive” portion of the RP Program
6 description in Exhibit JAN-2.

7 **Q. Are there any proposed changes in the administration of the RP program**
8 **included in the Phase II Plan?**

9 A. No. The Company will continue to operate with the existing third-party implementor
10 that is currently implementing the Pilot RP program. This implementor is
11 responsible for issuing rebates through online and paper applications.

12 The Company will also continue to utilize the program implementer for the
13 inspection of a portion of installed equipment to make sure that the equipment is
14 installed and matches the details provided in the application. Applications that have
15 been selected for inspection will not receive a rebate until the inspection has been
16 completed.

17 An evaluator is slated to begin an impact and process evaluation of the
18 program midway through 2025. The Company will continue to utilize the evaluator’s
19 services throughout Phase II at the levels indicated in Section 2.1 of Exhibit JAN-2.

20 **Q. Are there any proposed changes in the marketing of the RP Program**
21 **included in the Phase II Plan?**

22 A. No. The Company plans to continue the same successful marketing activities from
23 the Pilot. This means the Company will continue to work with HVAC installers and

1 plumbers to inform their customers of rebates, utilize marketing on the Company's
2 website, bill inserts, and social media. In addition, the Company will also continue
3 to promote RP incentives through its OAK program.

4 **Q. Please describe any proposed changes to the OAK Program included in**
5 **the Phase II Plan.**

6 A. There are no proposed changes to the OAK program. In Phase II, the OAK Program
7 will provide residential customers with a free online audit that will provide targeted
8 information for customers on how to reduce their energy usage and bills. The
9 program will also provide customers who complete the audit with free, targeted
10 energy savings kits. The program is expected to cost \$1.7 million in nominal dollars
11 over three years and save 431.5 thousand Dth of natural gas over the lifetime of
12 measures installed. The program is projected to provide present value TRC net
13 benefits of \$7.3 million with a BCR of 5.78. The program will also save 500.8 million
14 gallons of water and approximately 25 thousand tons of CO₂ over the lifetime of the
15 installed measures, which is equivalent to permanently removing over 964 cars from
16 the road.

17 To participate, customers will go through a web-based audit that collects basic
18 information about a customer's home and energy usage. Based on the information
19 provided, they will then receive customized recommendations along with estimated
20 impacts from implementing those recommendations. If the customer uses natural
21 gas to heat their home, then they will receive a kit with low-cost measures such as
22 outlet gaskets, caulk, and foam sealant along with instructions on how to install
23 them. If the customer uses natural gas for water heating, they will receive a kit that

1 includes low flow aerators and a high-efficiency showerhead. Customers using
2 natural gas for both water and to heat their home are eligible to receive both kits.
3 The OAK Program will be available to all residential customers at no cost.

4 **Q. Are there any proposed changes in the administration of the OAK**
5 **program included in the Phase II Plan?**

6 A. No. The Company will utilize the same two third-party implementers currently
7 under contract. One provides the online audit web-based application and the other
8 distributes the free energy saving kits to customers who request them.

9 The program will continue to be marketed through bill inserts, social media,
10 and The Company's website. As part of the recommendations from the online audit,
11 customers will be provided information about the RP program. The program
12 evaluator will complete a full program impact and process evaluation in Quarter 1 of
13 2025 on the first two program years of activity. The same evaluator will be utilized
14 for Phase II.

15 **Q. Please describe the SC Program.**

16 A. The SC Program is designed to overcome market barriers to energy efficiency space
17 heating, water heating, commercial cooking, and building shell upgrades by
18 providing incentives to businesses that install high efficiency equipment and make
19 improvements to their buildings. The program is expected to cost \$1.5 million in
20 nominal dollars over three years and save 544 thousand Dth of natural gas over the
21 lifetime of measures installed. The program is projected to provide present value
22 TRC net benefits of \$2.1 million with a BCR of 1.80. The program will also save 938.4
23 MWh of electricity and approximately 32.7 thousand tons of CO2 over the lifetime

1 of the installed measures, which is equivalent to permanently removing over 1,248
2 cars from the road.

3 The SC Program provides incentives for commercial sized boilers, water
4 heaters, fryers, griddles, dishwashers, process steam traps, single packaged vertical
5 units, advanced rooftop unit controls, and insulation and air sealing. The program
6 uses ENERGY STAR® criteria as a minimum efficiency level, when available. A full
7 list of the measures along with minimum efficiency levels and proposed incentives
8 can be found in the “Financial Incentive” portion of the SC Program description in
9 Exhibit JAN-2.

10 **Q. How will the SC Program be administered?**

11 A. The Company plans to operate with the existing third-party implementor currently
12 implementing the RP program. This implementor will be responsible for issuing
13 rebates through from online and paper applications.

14 The Company will also utilize the program implementor for inspections of a
15 portion of installed equipment to make sure that the equipment is installed and
16 matches the details provided in the application. Applications that have been selected
17 for inspection will not receive a rebate until the inspection has been completed.

18 The Company also plans to utilize the existing RP and OAK evaluator to
19 complete a full impact and process evaluation of the program once program activity
20 reaches levels of statistical significance.

21 **Q. How will information about the SC Program be shared with customers?**

22 A. The primary way customers will be informed about the SC Program will be from
23 HVAC installers and plumbers, already familiar with the RP Program, as well as

commercial kitchen equipment distributors. The Company also plans to promote the program to local chambers of commerce within the service territory. In addition, the Company will utilize marketing through traditional means such as the Company website, and social media advertising.

Q. Why is it important to include the SC Program in the Phase II Plan?

A. Small businesses are often faced with the need to replace costly heating, water heating, cooking, and process equipment. In many cases, these businesses are forced to choose lower efficiency equipment because of the more affordable upfront cost, without the ability to take advantage of the longer-term benefits of lower energy costs over time. The ability to provide incentives to lower the upfront cost of higher efficiency equipment enables small businesses to realize longer-term energy savings and ultimately lower energy bills. Reducing this upfront cost barrier for small businesses will help improve their profit margin by reducing operating cost, thereby improving the overall local economy.

Q. Please explain the portfolio wide costs associated with Plan.

A. The portfolio wide costs cover development, design, tracking, reporting, legal and administrative overhead that cuts across all the programs in the portfolio. This includes amortized costs for plan and portfolio development incurred for the Company's EE Phase II Plan filing. Portfolio wide costs are projected to become 10% of the final year's costs, and, over the three-year period, portfolio wide costs represent 12% of the portfolio's expenditures.

Q. How will Columbia Gas report on results of the Plan?

A. As explained in Section 1.6.4 of Exhibit JAN-2, the Company will provide an annual

1 report three months after the close of each program year. The program year ends on
2 December 31st, so the annual report will be provided in April of the following year.
3 This annual report will provide results for the previous year, including savings,
4 participation, spending, and cost-effectiveness along with descriptions of notable
5 activity and any updates to program design and delivery.

6 **Q. What conclusions do you reach about the proposed Phase II Plan?**

7 A. I find that the Phase II Plan is based on the successful implementation of the Pilot
8 and the updates are based on energy efficiency efforts across other utilities' natural
9 gas plans in Pennsylvania. The Phase II Plan will provide important natural gas
10 savings, and other resource savings. Furthermore, the Plan will provide substantial
11 economic benefits to the Company's residential and small commercial ratepayers,
12 the economy within the Company's territory, and Pennsylvania as a whole.

13 **Q. On the basis of these conclusions, what are your recommendations to**
14 **the Commission?**

15 A. I recommend that the Commission approve the implementation of the Phase II
16 Three-Year Energy Efficiency Plan.

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

18 A. Yes. I reserve the right to submit supplemental testimony during the course of the
19 proceeding. Thank you.

Joseph Nunley

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Professional Experience

Green Energy Economics Group, Inc. – Cuttingsville, VT

Partner 2024 to Present

Managing Consultant 2023 to 2024

In joining the Green Energy Economics Group team in 2023 Joe has been utilizing his experience and expertise gained throughout his 17+ years in the energy efficiency industry. Having spent time as a certified building scientist, energy auditor, weatherization contractor, utility program manager, and an executive at a highly respected program implementor, Joe has used his wealth of knowledge to lend insights into the design, analysis, and implementation of energy efficiency and distributed energy resource programs and portfolios in nine states and two Canadian provinces. He has a particular focus on EE policy analysis, program design and implementation, contractor and customer experience, and efficient systems design and implementation for individual programs and portfolios. Some recent project experience includes:

- Providing complete analysis and guidance on the 2025-2027 Mass Save Energy Efficiency Portfolio on behalf of the Massachusetts Attorney General's Office of Ratepayer Advocacy.
- Design, regulatory, and implementation support for voluntary gas and electric energy efficiency portfolios in Pennsylvania for UGI, PGW, and Columbia Gas of Pennsylvania.
- Design and tracking system improvement support for PSE&G in New Jersey for the Engineered Solutions (Commercial DSM) and Small Business Direct Install programs.

Performance Systems Development of NY – Ithaca, NY

Vice President of Program Services 2022 to 2023

Director of Program Strategy and Design 2020 to 2022

Senior Manager of Program Services 2019 to 2020

2016 – 2019

Senior Analyst, Energy Efficiency, UGI Utilities – Reading, PA

2015 – 2016

Energy Efficiency Trade Ally Network Manager, Puget Sound Energy – Bothell, WA

2013 – 2015

Director of Operations, MT Weatherization, Inc. – Harrisburg, PA

2007 – 2013

Owner/Founder, J&F Energy Solutions, Inc. – Harrisburg, PA

Affiliations and Certifications

Energy Efficiency Alliance (EEA) of Pennsylvania / New Jersey – Vice President, Board of Directors 2022 – Present

EEA Board of Directors 2021 – Present

EEA Membership Committee 2023 – Present

EEA DEI Working Group Lead 2023 – Present

EEA Policy Conference Planning Committee Member 2022, 2024

Association of Energy Service Professionals (AESP) – Gas Topic Committee Co-Chair 2019 – 2022

AESP National Conference Planning Committee 2021

Building Performance Institute (BPI) – Certified Building Analyst 2009 – Present

Association of Energy Engineers (AEE) – Certified Energy Manager 2016 – 2022

Project/Job Experience

Green Energy Economics Group, Inc.

Development and Implementation of Energy Efficiency and Conservation Plans

UGI Utilities, Inc. – Pennsylvania

(July 2023 – Present)

Assist UGI Utilities, Inc. with the development and approval of Energy Efficiency and Conservation (EE&C) Plans for their UGI Gas and UGI Electric divisions, including:

- Ongoing evaluation and portfolio planning activities for both UGI Gas and UGI Electric energy efficiency portfolios.
- Developing achievable efficiency scenarios.
- Designing a new five-year, \$72 million energy efficiency and conservation plan for UGI Gas.
- Supporting in Discovery responses for the five-year plan through the regulatory process.
- Providing ongoing implementation assistance for the current five-year energy efficiency and conservation phases for UGI Gas and UGI Electric.
- Provide ongoing support and assistance on evaluation activities in coordination with the Portfolio EM&V vendor for UGI Gas and UGI Electric.

Strategic Planning and Implementation of DSM Portfolio

Philadelphia Gas Work's (PGW) - Philadelphia, Pennsylvania

(July 2023 – Present)

- Assisting with ongoing program planning and implementation of both the Low-Income Usage Reduction Plan (LIURP) and the market-rate DSM portfolio.
- Providing analysis of new technology additions to improve the LIURP savings opportunity and customer experience.
- Develop enhancements to the contractor project cost-effectiveness tool.
- Providing ongoing technical support in program design and implementation for Gas DSM portfolio.
- Developed strategy to improve contractor efficacy in the LIURP through the formulation of an enhanced QA/QC and contractor training strategy.

Economic, Policy, and Program Design Analysis

Attorney General's Office of Ratepayer Advocacy- Massachusetts (October 2023 – Present)

- Provides economic, technical, program design, and policy related consulting services to the AG's office related to MA's 2025 to 2027 Energy Efficiency Plans.
- Provide focused guidance on equity related issues within the MA 2025-2027 Energy Efficiency Plans.
- Provide analysis and guidance on other decarbonization issues for the AG's office such as, Clean Heat Standard.

Economic and Policy Analysis

Consumer Advocate – Nova Scotia (February 2024 – Present)

- Member of DSM Advisory Group (DSMAG) on behalf of the Consumer Advocate of Nova Scotia to provide ongoing support for design and implementation of programs.
- Provided analysis and written commentary on the planning efforts for Efficiency One's (E1) 2026–2030 DSM Plan as it relates to program design, affordability, underserved communities, avoided costs, and cost-effectiveness methodology.

Program Management and DSM Data Tracking System Expert

Public Service Enterprise Group (PSE&G) – New Jersey. (Feb 2024 – Present)

- Consulted on program improvement and DSM data tracking system workflows for PSE&G's internally run commercial Engineered Solutions and Direct Install programs.
- Consulted on design improvements for internal and external vendor utilized project QA/QC field tool for Direct Install program.
- Provided enhancement recommendations for the scalability of the next phase of the commercial Engineered Solutions and Direct Install programs.

Development and Regulatory Support for DSM Portfolio

Columbia Gas of Pennsylvania - Pittsburgh, Pennsylvania (July 2023 – Present)

- Successfully developed, provided regulatory support for budgetary and design changes for the final year of the current three-year DSM portfolio.
- Provided implementation assistance to the current portfolio implementer on changes to the final program year of the current three-year phase necessary to achieve the filed design changes.
- Developed and provided regulatory support for a new three-year phase of the DSM portfolio with additional commercial programs added.
- Ongoing assistance with the implementation of the first three-year voluntary gas energy efficiency plan.
- Conducted evaluation activities for the Online Assessment Kit program.

Home Performance Contractor Business Growth Consulting

MT Building Services, Inc. – Harrisburg, PA (July 2023 – Present)

- Conducted a business operations analysis on mid-sized home performance company.
- Provided recommendations on staffing structure, company culture enhancements, training programs, and business growth opportunities.

- Ongoing consulting on the implementation of the recommendations developed as a result of the operations analysis.

Home Performance Contractor Business Development Consulting

Green Kite – Lancaster, PA

(March 2024 – Present)

- Provided analysis of business opportunity for contractor expansion throughout a tri-state area.
- Consulting on business growth strategy and operational impacts to growing home performance contractor.

Program Implementer Subject Matter Expert Consulting

The JPI Group – Philadelphia, PA

(September 2024 – Present)

- Educating workforce development program implementer transition to the energy efficiency industry
- Building workforce development processes specific to the energy efficiency industry
- Conduct market assessments to assist business development strategy efforts

Performance Systems Development of NY

Executive Leadership

Vice President of Program Services

(October 2022 – July 2023)

- Lead an organizational business unit of 70+ energy efficiency professionals implementing programs in 13+ states
- Direct management of the Program Senior Management team consisting of 7 Senior Managers and Directors
- Management responsibility of \$15 million operational budget equaling two-thirds of the company's overall operating budget and revenue.
- Responsible for Program Services business unit growth and operational strategy
- Designed and implemented operational growth strategy that led to 30% revenue growth and 25% staffing growth that established the future models for company operational growth.
- Executive Leadership team responsibility for company-wide growth and operational strategy.
- Led a cross-business unit collaboration team consisting of the leaders from the Software Development and Engineering business units to improve inter-business unit collaborative efficiency.

Program Design Work

Director of Program Strategy and Design/Senior Manager

(July 2019 – October 2022)

- Responsible for the strategy and program design for Residential New Construction, Residential Retrofit (Weatherization), Quality Assurance, Energy Codes and Training, Commercial Custom, and Equipment Rebate Programs throughout the Northeast and Midwest.

- Designed program design proposals for all new contract opportunities and secured ten new program contracts based on finding program improvements to be gained over existing implementation strategies for each respective opportunity.
- Developed a protocol for and conducted tune-ups of 25 existing programs that consisted of a deep analysis of each program being implemented by the company to inform program design improvements.
- Conducted start-up/launch manager duties for all new program launches throughout the Northeast and Midwest.

UGI Utilities

Program Design, Startup, and Portfolio Development

Senior Analyst, Energy Efficiency

(October 2016 – June 2019)

- Oversaw the launch of the first every UGI Gas Energy Efficiency Portfolio
 - o Developed rebate applications and processes
 - o Set up DSM data tracking and reporting system
 - o Designed and launched new residential retrofit program in year 2 of the portfolio launch
- Evaluated and contracted with program implementers for Residential Retrofit and Residential New Construction Programs
- Developed and launched an energy efficiency portfolio for UGI Operating Company Penn Natural Gas (PNG)
 - o Expanded the UGI Gas EE&C Portfolio to include the Penn Natural Gas operating company
 - o Conducted plan filing research and design
 - o Experienced in the end-to-end regulatory process from utility commission filing through settlement approval
- Designed, developed, and launched a commercial equipment midstream pilot, which turned into a program offering for UGI and PNG portfolios
 - o Used data to determine reason for low performance in commercial equipment downstream rebate program
 - o Worked with commercial HVAC and kitchen equipment distributors to develop, design, and implement midstream pilot
 - o Successful pilot turned into a full program offering for both utility portfolios
- Oversaw the design and development of an online marketplace addition to the residential downstream rebate program offering
 - o Design feedback and implementation protocols for a newly added marketplace instant rebate offering for residential customers
- Successfully redesigned the Residential Retrofit program based on program data and contractor engagement assessment to increase program participation
 - o Data analysis show that program was not reaching intended market penetrations
 - o Coordinated with participating contractors to incorporate feedback and re-design the program which led to increased customer adoption, contractor satisfaction, and goal achieving market penetration

- Developed and launched an energy efficiency portfolio for the newly consolidated UGI Gas Utility (UGI, PNG, and CPG operating companies' merger)
 - o In 2018, three operating companies in Pennsylvania merged into one
 - o Designed a new 5-year portfolio filing for the consolidated company
 - o Designed new program offerings and expansions of existing programs to usher the portfolio through the entire regulatory process

Program Management

Senior Analyst, Energy Efficiency

(October 2016 – June 2019)

- Managed all aspects of Residential, Small Commercial, and C&I energy efficiency programs
- Managed and internally implemented small commercial energy efficiency program
- Built and developed trade ally networks to be engaged in the program
 - o Designed trade ally requirements per program
 - o Held various contract meetings to discuss programs and enroll new contractors
 - o Developed continuous improvement engagement process with participating and new contractors

Puget Sound Energy

Trade Ally Engagement, Program Development, and Program Management

Trade Ally Network Program Manager

(September 2015 – October 2016)

- Managed a network of over 350 energy efficiency trade allies spanning all residential and commercial and industrial efficiency programs
- Responsible for enrolling new trade allies, network engagement, and contract management
- Responsible for conducting financial analysis on program referral program which contractors paid a referral fee for executed leads that came through the program
 - o Reconfigured the financial referral program based on cost changes in the trades, materials, and contractor customer acquisition cost
- Developed scoring metric methodology to rank contractors which fed the contractor referral algorithm
- Established and implemented quarterly contractor roundtable series to inform program improvements and maintain connection within field operations
- Designed specification requirements for updated referral system being included in the utilities new DSM tracking system
- AEE Certified Energy Manager

MT Weatherization

Operations, Process, and Leadership

Director of Operations

(June 2013 – June 2015)

- Managed integration of J&F Energy Solutions and MT Weatherization following the acquisition. Integrated all systems, processes, staffing, equipment, and facilities
- Operational responsibility over:
 - o 3,000+ energy audits and quality control inspections per year.
 - o 1,000+ weatherization installs per year.

- o 2,000+ appliance deliveries per year.
 - o Fully responsible for all company operations.
- Designed and implemented improved processes around workflow, employee education, and client management
- Opened an expansion branch in Western Pennsylvania upon winning new contract award
 - o Hired and trained local staff, implemented MT processes and procedures in the new branch, established client management and client growth processes

J&F Energy Solutions

Company Startup, Ownership, Expansion, and Building Science Expertise

Owner/Founder

(March 2007 – June 2013)

- BPI Certified Building Analyst
- Personally performed 1,000+ energy audits and quality control inspections.
 - o Performed baseload and comprehensive diagnostic energy audits for several income eligible utility programs throughout Pennsylvania.
 - o Performed quality control inspections on contractor weatherization projects for income eligible utility programs throughout Pennsylvania.
 - o Performed comprehensive diagnostics energy audits for market rate customers tied to utility incentive programs. Price estimated and sold projects to customers.
- Company performed over 3,000 energy audits and quality control inspections per year across Pennsylvania.
- Designed and implemented data management systems for audit data transfer to utility and job tracking systems to assist Utility Low-Income Usage Reduction Programs (LIURPs) managing budgets and job production.
- Developed policy and procedure manual for PPL Electric Utilities LIURP as member of 5-person SME panel.
- Developed and implemented a plan for the Central PA Region of Enterprise Rental Car to achieve corporate mandated energy reduction goals. Analyzed utility bills across 30 locations to identify the highest users. Completed energy audits on the 8 highest energy consuming buildings. Implemented large scale weatherization/spray foam projects on 5 of the highest users and smaller scale projects, including equipment controls, on the other 3 high use buildings.
- Secured, implemented, and expanded LIURP contracts with PPL Electric Utilities, FirstEnergy, and Columbia Gas of Pennsylvania.
- Hired, trained, and managed a team of 13 energy auditor/quality control inspectors and 4 weatherization crews (subcontractor).
 - o During a time when weatherization and building science expertise was not readily available, I hired and trained a large group of new industry members coming from a variety of different backgrounds and at different points in their careers. From entry level recent high school graduates to veterans with 20+ years of military experience, training protocols were designed to gain expertise, while learning how best to serve customers.

Speaking Engagements

Expert Panelist, *"How to Get Software and Tech Talent in the Energy-Utility Sector"*, Per Scholas Webinar Series 2024

Expert Panelist, *"Interview with a Contractor"*, Keystone Energy Efficiency Alliance, Policy in Action Conference 2024

Presenter, *"Homes, HEAR, and IRA Tax Credits: What Contractors Need to Know to be Ready"*, Building Performance Association, Quarterly Contractor Meeting 2024

Expert Panelist, *"Efficiency Landscape of Pennsylvania"*, Keystone Energy Efficiency Alliance, Annual Policy Conference 2022

Expert Panelist, *"Coming Together for the Customer, 4 Utilities Achieving Gas and Electric Goals"*, Association of Energy Service Professionals Annual Conference 2021

Presenter, *"Using Smart Thermostats to Engage residential Customers and Drive Comprehensive Retrofit Projects"*, Association of Energy Service Professionals Annual Conference 2020

Expert Panelist, *"Engaging Contractors: The Right Time to Drive Program Success"*, Midwest Energy Efficiency Alliance Annual Conference 2020

Keynote Speaker, *"Impacts of Climate Change: How your work helps reverse the trend"*, UGI Utilities Annual LIURP Contractors Meeting 2019

Expert Panelist, *"Gas Utility Program Successes and Lessons Learned in Pennsylvania"*, Keystone Energy Efficiency Alliance Annual Policy Conference 2019

Annual Presenter, Pennsylvania Public Utility Commission Be Utility Wise Seminars, 2011 – 2015

Testimony and Proceeding Participation

Forum	On Behalf Of	Docket/Matter	Date	Issues Addressed
Massachusetts Department of Public Utilities	Massachusetts Office of the Attorney General	D.P.U. 24-140 through D.P.U. 24-149 - 2025-2027 Three-Year Energy Efficiency Plan	November-24	Low-income program design. Quality assurance and quality control processes. Administrative costs.

Publications

Love, Theodore. Nunley, Joe. "Using Smart Thermostats to Engage Residential Customers and Drive Comprehensive Retrofit Projects" In *Proceedings of the ACEEE 2020 Summer Study on Energy Efficiency in Buildings*, Washington, D.C.: American Council for an Energy Efficient Economy.

Love, Theodore. Nunley, Joe. "The Future for Residential Gas Efficiency is Combined". *Strategies*. Association of Energy Service Professionals. January 11, 2019.

Nunley, Joe. Douglas, Paul. Stapleton, Barbara. "Designing A Proven Workforce Development Model that Impacts Everyone" In *Proceedings of the ACEEE 2024 Summer Study on Energy Efficiency in Buildings*, Washington, D.C.: American Council for an Energy Efficiency Economy.

Education

Lycoming College – Williamsport, PA
B.A., *History*, 2006. Minor: *Psychology*

Columbia Gas of Pennsylvania

Three-Year Energy Efficiency Plan – Phase II

January 1, 2026 – December 31, 2028

March 20, 2025

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1 Introduction and Background

1.1 Plan Overview

This plan provides a detailed description of the design and implementation of the energy efficiency and conservation portfolio (“EE&C Portfolio” or “Portfolio”) that Columbia Gas of Pennsylvania, Inc. (“Columbia Gas” or “the Company”) is proposing to offer as Phase II of its Three-Year Energy Efficiency (“Plan”). The Plan builds on the success of the current pilot Plan offering and other voluntary gas energy efficiency plans offered by natural gas distribution companies serving Pennsylvania and specifically targets residential and small commercial customers. This Plan will transition from the successful pilot into a consistent energy-efficiency offering for Columbia Gas.

The Plan has a three-year duration, beginning January 1, 2026, and ending December 31, 2028. Over the three years of the Plan, Columbia Gas plans to spend \$7.9 million on the administration and delivery of two residential energy efficiency programs and one commercial energy efficiency program. The programs are projected to save 2.7 million Dth of natural gas over the lifetime of the measures installed. From a total resource perspective, the portfolio present value of benefits is \$28.6 million, with \$11.5 million in present value of costs, leading to a present value of net benefits of \$17.1 million and a TRC BCR of 2.49. Furthermore, the energy efficiency programs are expected to save 7,629 MWh of electricity, 508 million gallons of water, create between 81 and 162 jobs, and avoid the emission of CO₂ equivalent to over 6,286 cars being removed from the road over the lifetime of installed measures.

1.2 Plan Development

Phase II of the Plan was developed to help Columbia Gas’ residential and small commercial customers to address barriers to using natural gas more efficiently. It has three programs:

- Residential Prescriptive (RP) Program

- Online Audit Kit (OAK) Program
- Small Commercial (SC) Program

The RP Program is based on rebate programs run in Pennsylvania by other natural gas distribution companies. The OAK Program is based on a successful program run by Columbia Gas of Virginia for over the past decade. Both programs will continue to run on the successful implementation of the current pilot phase of programs offered by Columbia Gas.

As a new addition for Phase II of the Plan, the SC Program is based on rebate programs run in Pennsylvania by other natural gas distribution companies to help small commercial customers make high efficiency upgrades to their businesses and reduce their natural gas consumption.

Various market characteristics were gathered for Columbia Gas' territory, including avoided costs for natural gas and electricity, demographic, building stock, and equipment market characteristics. Next, measures were characterized and screened for cost effectiveness using the TRC test. Incentive levels were established for these measures and projects, generally set to be in-line with the other programs in Pennsylvania. The cost-effective measures and projects were then used to calculate savings and maximum participation levels. Programs were staged to account for the ramp-up required for new programs. Finally, non-incentive budgets were developed to address fixed and variable costs associated with each program and the portfolio.

1.3 Portfolio Costs

The following table provides an overview of the spending by year and program for the Plan. The maximum projected budget in a year is \$2.8 million in FY 2028, approximately 0.5% of Columbia Gas' FY 2020 revenues.¹ Although Act 129's requirements are not mandatory for voluntary natural gas distribution company energy efficiency programs, this level is well under the 2% cap that Act 129

¹ \$3.8 million is 0.7% of total 2020 revenues of \$555 million from Columbia's Annual Report of Columbia Gas of Pennsylvania, Inc. Year Ended December 21, 2020 at p. 26.

imposes on electric efficiency programs in Pennsylvania.² It is anticipated that all costs will be recovered from the eligible rate classes through an annual rate reconciliation process based on participation in the programs, excluding Customer Assistance Program (“CAP”) customers. The rate classes eligible for the programs will be all residential rate classes and small commercial customers with the rate schedules of SGSS, SCD and SGDS. Table 2 below, provides a breakdown of the projected total costs to be allocated between residential and commercial customers.

Table 1. Projected Spending for the Plan by Program

Projected Costs (Nominal)	2026	2027	2028	2026 - 2028
Residential Prescriptive Program	\$1,190,625	\$1,282,950	\$1,285,250	\$3,758,825
Online Audit Kit Program	\$509,700	\$548,300	\$636,900	\$1,694,900
Small Commercial Program	\$431,538	\$487,433	\$594,883	\$1,513,854
Portfolio Wide Costs	\$335,000	\$289,000	\$293,000	\$917,000
Total	\$2,466,863	\$2,607,683	\$2,810,033	\$7,884,579

Table 2 Projected Spending for the Plan by Customer Class

Projected Costs (Nominal)	2026	2027	2028	2026 - 2028
Residential	\$1,963,496	\$2,058,284	\$2,152,327	\$6,174,108
Small Commercial	\$503,366	\$549,399	\$657,707	\$1,710,472
Total	\$2,466,863	\$2,607,683	\$2,810,033	\$7,884,579

The portfolio-wide cost lines from the previous table are costs that apply to all programs in the EE portfolio. They are costs incurred at the portfolio level for program development, design, tracking, reporting, and administrative overhead. Development costs for the portfolio occur in the first year as programs are designed and reporting infrastructure is put in place. These costs become a smaller percentage of the portfolio as the rest of the programs ramp up. In the final year, the portfolio wide costs represent 10% of the portfolio total cost, and, over the three-year period, they represent 12% of the portfolio’s costs. The following table provides a portfolio-level look at costs by category.

² See 66 Pa.C.S. § 2806.1(g) (limiting the total cost of an EDC’s EE&C Plan to 2% of the EDC’s total annual revenue as of December 31, 2006).

Table 3. Projected Efficiency Portfolio Budgets by Category

Category	2026	2027	2028	2026 - 2028
Customer Incentives	\$1,256,013	\$1,462,083	\$1,585,983	\$4,304,079
Administration	\$940,650	\$868,025	\$908,950	\$2,717,625
Marketing	\$173,950	\$135,075	\$140,850	\$449,875
Inspections	\$71,250	\$82,500	\$89,250	\$243,000
Evaluation	\$25,000	\$60,000	\$85,000	\$170,000
Total	\$2,466,863	\$2,607,683	\$2,810,033	\$7,884,579

1.4 Portfolio Benefits

1.4.1 Natural Gas Savings

The following tables provide projected natural gas savings by program and sector for the Plan.

Table 4. Projected First Year Gas Savings by Program (Dth)

Program	2026	2027	2028	2026 - 2028
Residential Prescriptive Program	27,904	29,988	31,616	89,507
Online Audit Kit Program	10,914	12,607	14,299	37,820
Small Commercial Program	7,889	11,586	13,123	32,598
Total	46,707	54,180	59,038	159,925

Table 5. Projected Lifetime Gas Savings by Program (Dth)

Program	2026	2027	2028	2026 - 2028
Residential Prescriptive Program	535,834	576,820	606,084	1,718,739
Online Audit Kit Program	124,541	143,835	163,130	431,506
Small Commercial Program	151,033	188,733	204,113	543,880
Total	811,409	909,389	973,327	2,694,126

1.4.2 Other Resource Savings

The following table shows electric savings for measures installed under the energy efficiency programs in the EE&C Portfolio. The electric savings are secondary savings from measures that primarily save natural gas, such as air-conditioning savings from thermostats. This section contains ancillary water savings from gas efficiency measures that also save water, such as low-flow faucet aerators and showerheads.

Table 6. Projected Electric and Water Savings

	2026	2027	2028	2026 - 2028
First Year				
Energy (MWh)	152	176	197	525
Demand (kW)	44.3	49.5	54.9	148.8
Water (Million Gallons)	14.6	16.9	19.1	50.7
Lifetime				
Energy (MWh)	2,242	2,549	2,838	7,629
Water (Million Gallons)	146.8	169.3	191.8	508.0

1.4.3 Emission Reductions

This section contains projections for CO₂ emission reductions due to the energy efficiency programs. The total lifetime savings of 164.6 thousand tons of CO₂ is equivalent to removing over 6,286 cars off the road. The following table breaks out the emission reductions due to gas savings and electric savings. While the emissions reductions are projected below, the main TRC test for the portfolio does not include any monetized value for these emissions reductions.

Table 7. Projected Lifetime CO₂ Emission Reductions by Energy Source (Short Tons)

Savings Source	2026	2027	2028	2026 - 2028
Natural Gas	47,467	53,199	56,940	157,606
Electricity	2,048	2,329	2,592	6,969
Total	49,515	55,528	59,532	164,575

1.4.4 Job Creation

Investing in cost-effective energy efficiency creates jobs in two ways, one direct and the other indirect, as discussed in a 2012 white paper from the ACEEE.³ Direct job creation results from hiring related to implementing the programs. Indirect job creation results from the substitution of capital spent on natural gas with capital spent in the local economy. Additional jobs are created by the indirect or income effect from cost-effective energy efficiency investment. Further, the net economic benefits from efficiency investment reduce household and business gas bills and raise household disposable incomes and business profitability.

³ "Energy Efficiency Job Creation: Real World Experiences" Bell, Casey J. American Council for an Energy-Efficiency Economy. October 2012.

Customers will tend to spend most of this additional money and save the rest. Businesses will tend to re-invest in their business to grow, add more employees, and/or create better benefits for their employees. This additional spending creates a “multiplier” effect through the cycle of re-spending of the initial cost savings, which stimulates aggregate demand for goods and services. Satisfying increased demand for goods and services requires more labor. While some of the jobs created leak into the broader U.S. and global economy, a good portion (possibly higher than 80%) of jobs created due to energy efficiency stay within the Commonwealth. The approach of looking at net job creation through both direct means and with economic multiplier effects is endorsed in the 2012 white paper from ACEEE.⁴

The number of jobs created from investments in energy efficiency directly relates to the total resource value of the energy that these measures save. Studies of employment impacts of Demand Side Management (“DSM”) use energy savings as a surrogate for total resource value. A meta-study of U.S. data found that estimates for the number of jobs created had a wide range, but that most studies estimate that between 30 and 60 net jobs are created by saving one TBtu.⁵ In New York, New Jersey, and Pennsylvania, the ACEEE projected that 164,320 jobs, or 59 for every TBtu saved, could be attributed to EE in 1997 through 2010.⁶

As shown in the following table, Columbia Gas estimates that its gas energy efficiency programs portfolio will generate between 81 and 162 net additional jobs over the lifetime of the efficiency measures installed over the next five-years. This range is based on assuming that each TBtu of gas savings creates between 30 and 60 full-time equivalent jobs in Pennsylvania.

⁴ Energy Efficiency Job Creation: Real World Experiences” Bell, Casey J. American Council for an Energy-Efficiency Economy. October 2012.

⁵ Laitner, Skip, and Vanessa McKinney. June 2008. *Positive Returns: State Energy Efficiency Analyses Can Inform U.S. Energy Policy Assessments*. Washington, D.C.: American Council for an Energy Efficiency Economy.

⁶ Nadel, Steven, Skip Laitner, Marshall Goldberg, Neal Elliott, John DeCicco, Howard Geller, and Robert Mowris. 1997. *Energy Efficiency and Economic Development in New York, New Jersey, and Pennsylvania*. Washington, D.C.: American Council for an Energy Efficiency Economy.

Table 8. Estimated Job Creation due to Energy Efficiency Programs

JOB CREATION IMPACTS OF GAS EFFICIENCY PORTFOLIO			
	30 Jobs/TBtu	45 Jobs/TBtu	60 Jobs/TBtu
TOTAL PORTFOLIO			
2026	24	37	49
2027	27	41	55
2028	29	44	58
TOTAL	81	121	162

1.5 Cost-Effectiveness Analysis

The following table provides Total Resource Cost (TRC) test cost-effectiveness projections for the Plan.

Table 9. TRC Cost-effectiveness Summary of Portfolio (2025\$)

Program	Total Resource PV Benefits	Total Resource PV Costs	Total Resource PV Net Benefits	Total Resource B/C Ratio
Residential Prescriptive Program	\$15,082,158	\$6,514,710	\$8,567,448	2.32
Online Audit Kit Program	\$8,852,798	\$1,532,931	\$7,319,867	5.78
Small Commercial Program	\$4,670,353	\$2,600,636	\$2,069,717	1.80
Portfolio Wide Costs	\$0	\$834,284	(\$834,284)	-
EE Programs	\$28,605,309	\$11,482,561	\$17,122,749	2.49

While the portfolio is cost effective using the primary TRC Test, if the values for demand-response induced pricing effects (“DRIPE”)⁷ and internalized market prices for carbon dioxide (“CO₂”) are included, the portfolio would show substantially more benefits.

1.5.1 Cost-Effectiveness Analysis Methodology

The cost-effectiveness results reported in the Plan follow standard industry practices for utilizing the TRC Test for cost effectiveness. The TRC Test methodology used is similar to that used by other natural gas distribution companies serving Pennsylvania that offer energy efficiency programs, and by the Act 129 Utilities. To calculate benefits, projected natural gas, electricity, and water

⁷ DRIPE accounts for the suppression effects on wholesale prices from reduced usage due to DSM.

savings are multiplied by avoided costs, and this stream of future values is discounted to the present. The cost side of the test consists of the present value of all incremental costs incurred by participants, including net operation and maintenance costs, and the non-incentive costs incurred by the portfolio administrator. If the benefits outweigh the costs (the benefit-cost ratio is above one), then the total cost of energy services for an average customer within the territory will fall and the portfolio is considered cost effective

The analysis used a real discount rate (RDR) of 3%. The RDR was calculated using an assumption of a nominal discount rate ("NDR") of 5% and inflation rate of 2.0%, which comes from the Act 129 Phase IV TRC Test Order.⁸

1.5.2 Avoided Costs

The avoided cost of natural gas for Columbia Gas of Pennsylvania used in this plan are based on the Phase I avoided costs with updates to NYMEX futures and the latest US Energy Information Administration's ("US EIA") Annual Energy Outlook ("AEO") forecast. In general, the avoided costs were developed in a similar manner to other Pennsylvania natural gas distribution companies offering energy efficiency programs and includes the costs of baseload and storage capacity, along with an estimate of avoidable local distribution costs. The avoided costs for baseload capacity were computed as the cost of Columbia Gas Transmission (TCO) FTS, Henry Hub commodity was priced using NYMEX futures from January 17, 2025, through 2029. 2023 AEO⁹ projections were used from 2030 onward. The avoided costs for heating load were computed from the Columbia Gas Transmission SST rate, plus refill from the Columbia FSS rate, adjusted for load factor over the heating season. Commodity costs include the commodity charge and gas retention from the TCO tariffs. The avoided costs also include an allowance for avoidable load-related distribution investments, borrowed from UGI's estimates in its 2018 EE&C filing, at Docket No. R-2018-3006814.

⁸ Act 129 Phase IV 2021 Total Resource Cost (TRC) Test (Case No. M-2019-3006868). Final Order dated December 19, 2019. P. 20

⁹ The 2023 AEO forecast is the most recent forecast available from the US EIA, as there was no 2024 AEO forecast due to a major overhaul of the US EIA's projection model for the upcoming 2025 forecast.

The Plan also uses avoided costs for electric energy and peak demand based on weighted average annual values from the electric utilities in Columbia Gas' territory, including Duquesne Light Company, Metropolitan Edison Company, Pennsylvania Electric Company, Pennsylvania Power Company, and West Penn. Values for the various electric utilities came from the respective Act 129 Phase IV filings for each utility.

Avoided costs for water came from the Act 129 Phase IV TRC Test Order.

1.6 Implementation

1.6.1 Program Staging

The Company anticipates that it will require six months post Plan approval to finalize implementation details, hire vendors, and begin the marketing and outreach for the newly implemented SC Program. The RP and OAK Programs will be a continuation of the existing programs offered by Columbia Gas. Provided that Plan approval is received by October 1, 2025, all programs are projected to begin operations during the first quarter of 2026.

1.6.2 Administration

The Portfolio will be managed by Columbia Gas, who will engage the services of various contractors to fulfill all the roles required to implement the Plan. The table below describes the main roles in the management of the Plan.

Table 10. Overview of Administration Roles

Role	Description
Plan Administrator	Primarily responsible for program and portfolio planning, management and reporting. Supervises and manages all other roles.
Implementation and Design Consultants	Provides assistance in the design and implementation on multiple aspects of the portfolio, including, but not limited to, program design, reporting, marketing, and training.
Implementation Contractor	Directly responsible for main aspects of program delivery, including but not limited to, customer engagement and retention, technical assistance, measure installation, rebate processing, program tracking, inspection, and reporting.
Evaluator	Performs independent program and portfolio evaluations that are used to verify savings and guide future plans.

1.6.3 Marketing

Columbia Gas will use its current website for the programs with the addition of the SC Program, for which multiple streams of advertising will lead back to, such as print, online ads, social media, bill inserts, and trade ally outreach.

Columbia Gas will also perform outreach to local businesses and trade organizations (builders, contractors, electricians, plumbers, HVAC service providers, equipment suppliers, etc.) to familiarize them with program opportunities, energy efficiency practices and implementation requirements and to utilize them, where appropriate, as one of the program's service delivery channels.

- Targeting equipment manufacturers, distributors, installation contractors and retailers/vendors to make sure they offer high-efficiency equipment and can make customers aware of available incentives.
- Partnering with community-based organizations to develop outreach and program delivery strategies.
- Targeting local chambers of commerce and business organizations to spread awareness about the newly launched SC Program.

Additional details for each program are in the individual program plans, and Columbia Gas will develop a more detailed marketing strategy for each of the programs and for the entire portfolio as part of the program setup.

1.6.4 Reporting

Columbia Gas will submit an annual report on the Plan each April, three months after the close of the program year. This report will provide information on activity for the previous year and progress towards three-year goals, including, but not limited to:

- First year and lifetime savings;
- Participation;
- Spending;
- Cost effectiveness;
- Highlights of portfolio and program activity; and
- Updates to program delivery and design.

In-order to tie savings and costs together as effectively as possible, results will be reported based on commitments made. Any measures that have been verified as installed within a program year along with any costs committed to these measures, including administration costs, will be counted for that year.

1.6.5 Program Flexibility

To make sure that the EE&C Portfolio is able to address changing market conditions and improve service delivery as quickly as possible, Columbia Gas requires flexibility in the allocation of budgets and implementation of program improvements. This plan document provides the principles and three-year goals that Columbia Gas is seeking, but certain adjustments, such as providing incentives for new measures or moving budgets between years and programs, may be required to meet these goals. Columbia Gas will include any such adjustments in its annual report but does not anticipate seeking initial approval for such updates. Columbia Gas will file an updated Plan in anticipation of material changes that may have a serious effect on goals, such as:

- The addition or removal of a program;

- A need for total funding levels above those approved for the plan term;
- Greater than 25% of the total budget is anticipated to be moved between the residential and small commercial sectors and
- Significant changes to cost-effectiveness projections, such as an update to avoided costs or a large reduction in portfolio spending projections.

1.7 Evaluation, Measurement, and Verification

1.7.1 Technical Reference Manual

To maintain consistency with existing gas efficiency programs in Pennsylvania, Columbia Gas will utilize a Technical Reference Manual ("TRM") based on the most recent version of the Columbia Gas's TRM. Newly added small commercial measures will be based on the accepted TRM for UGI Gas, Inc. The Columbia Gas TRM will only contain those measures relevant to the programs proposed in this plan and will include updates to some measure assumptions to calibrate them to Columbia Gas' service territory (such as equivalent full load heating hours and heating degree days). In the future, any results from program evaluations that affect deemed savings calculations will also be added to the TRM. The proposed updated TRM is included as Exhibit JAN-3 Columbia Gas Technical Reference Manual to this plan.

1.7.2 Tracking System

Columbia Gas will require that its implementors collect all relevant customer, application, measure, and contractor information and that this data is provided in a timely fashion. Columbia Gas will regularly review this data, and will aggregate cost, savings, and participation data to a centralized database controlled by Columbia Gas that will be the source for program management and reporting.

1.7.3 Inspections

Inspections may be performed on a sub-set of applications before any incentive is paid. Inspectors will determine whether the measure is operational and matches the application, and they will solicit customer feedback on the programs. Inspection rates for prescriptive programs will be designed to gather a statistically

significant sample of program activity. See individual program plans for additional details.

1.7.4 Evaluations

Columbia Gas will monitor the ongoing progress of the Plan to provide the highest possible service to customers, while maintaining controls to maximize the potential for savings and costs to be properly verified and counted. Columbia Gas will closely track program data, perform inspections of completed projects, and perform periodic evaluations for all the programs.

Columbia Gas will, at a minimum, evaluate each of its programs once adequate participation levels have been reached and a full 12 months of post-participation billing data has been collected. As part of the initial program development, Columbia Gas will work with the selected evaluator to establish the methodology and goals of the evaluation. Initial objectives include:

- Verifying energy savings and associated costs;
- Assessing market attitudes towards the program, including contractors, customers, and efficient equipment suppliers; and
- Measuring the effectiveness of current program design, marketing, and service delivery.

The evaluation section of the individual program descriptions includes additional details on evaluation schedules and goals unique to that program.

2 Program Plans

2.1 Residential Prescriptive

Objective	The Residential Prescriptive (RP) program is designed to overcome market barriers to energy efficient space and water heating equipment and building shell upgrades in the residential sector through rebates and customer awareness. The objective of the program is to avoid lost opportunities by encouraging consumers to install the most efficient gas heating technologies available when replacing older, less efficient equipment and make long lasting improvements to their building shell through insulation and air sealing. The program also aims to strengthen Columbia Gas' relationship with HVAC contractors, suppliers, and other trade allies.				
Eligible Rate Class	RDS/RSS, SGSS1, SCD1, SGDS1, SGSS2, SCD2, SGDS2				
Cost Effectiveness	<i>Three-Year Cost-Effectiveness Results (2025\$)</i>				
	CE Test	PV Benefits	PV Costs	PV Net	BCR
	TRC Test	\$15,082,158	\$6,514,710	\$8,567,448	2.32
	Gas Admin Test	\$14,646,893	\$3,407,849	\$11,239,044	4.30
Savings Projections	<i>Three-Year Savings Projections</i>				
	First Year Savings	2026	2027	2028	2026 – 2028
	Natural Gas (Dth)	27,904	29,988	31,616	89,507
	Electric Energy (MWh)	132.8	142.7	157.2	432.7
	Peak Demand (kW)	42.0	45.3	50.0	137.3

	Water (Million Gallons)	0.0	0.0	0.0	0.0
	Lifetime Savings	2026	2027	2028	2026 – 2028
	Natural Gas (Dth)	535,834	576,820	606,084	1,718,739
	Electric Energy (MWh)	2,048.4	2,208.0	2,434.1	6,690.5
	Water (Million Gallons)	0.0	0.0	0.0	0.0
Budget Projections	Three-Year Budgets (Nominal)				
	Costs by Category	2026	2027	2028	2026 - 2028
	Customer Incentives	\$825,625	\$894,950	\$944,250	\$2,664,825
	Administration	\$225,000	\$207,000	\$215,000	\$647,000
	Marketing	\$79,000	\$55,000	\$56,000	\$190,000
	Inspections	\$61,000	\$66,000	\$70,000	\$197,000
	Evaluation	\$0	\$60,000	\$0	\$60,000
	Total	\$1,190,625	\$1,282,950	\$1,285,250	\$3,758,825
Participation Projections	Three-Year Participation Projections				
	Projected Units	2026	2027	2028	2026 - 2028
	Furnace - ENERGY STAR	900	950	975	2,825
	Boiler - 94+ AFUE	45	50	50	145
	Combi Boiler - 94+ AFUE	70	80	85	235
	Wi-Fi Thermostat - ENERGY STAR	1,400	1,500	1,650	4,550
	Tankless Water Heater - ENERGY STAR	220	235	240	695
	Gas Heat Pump (Furnace Baseline)	1	1	1	3
	Gas Heat Pump (Boiler Baseline)	1	1	1	3
	Insulation and Air Sealing	175	190	210	575

	Boiler Reset Controls	20	30	40	90
	Fireplace Inserts	5	8	10	23
	SPVUs	15	25	30	70
	Total	2,852	3,070	3,292	9,214
Program Design	The RP Program follows the same design as the current program of the same name. The same measures from the current program are also included with the same incentive levels. In addition, incentives for efficient natural gas fireplace inserts, boiler reset controls, and efficient single package vertical units (“SPVUs”) are being offered. SPVUs are being offered to provide multi-family building owners and occupants with an efficient option for space heating where there are many barriers to installing efficient natural gas furnaces. The RP Program offers rebates for qualifying insulation and air sealing project, residential-sized space and water heating equipment and controls. For most measures, customers will have a contractor install the measure and receive a rebate to offset some of the incremental cost of the higher efficiency equipment. Smaller measures, such as Wi-Fi enabled thermostats, will only require a valid proof of purchase before a rebate is issued. Customers will be encouraged to process rebates through an online portal but may also submit a paper application through the mail. Columbia Gas may also provide the option to purchase qualified smart thermostats via an online marketplace. If program funds begin to run low, incentive levels may be lowered, or equipment removed from the program if additional budget adjustments cannot be made. Columbia Gas will aim to provide as little interruption to customers as possible due to such adjustments.				

	Columbia Gas will continue to examine other equipment for potential inclusion in the program, as well as the relative market adoption of equipment already receiving incentives.
Target Market and End Uses	The RP targets residential consumers who use natural gas to heat their homes and/or generate hot water. In general, the program aims to incentivize only the highest levels of efficient equipment on the market. The minimum level of efficiency for measures offered through the RP program will be ENERGY STAR®, when available, and in some cases may exceed ENERGY STAR®. On the space heating side, the program provides incentives for ENERGY STAR® labeled smart thermostats, furnaces, high efficiency boilers, combination boilers, and high efficiency natural gas-fired heat pumps. ENERGY STAR® smart thermostats offer the potential for deeper savings than traditional programmable thermostats due to the wide range of features and feedback they offer. ENERGY STAR® requirements for furnaces drive customers toward the highest efficiency tier of condensing units (95+ AFUE). The program would also require boilers to go towards the highest efficiency tier with an AFUE of at least 94. Offering incentives for combination space and water heating boilers addresses two types of end-use with one piece of equipment. These “combi boilers” also address issues with orphaned water heaters having existing atmospheric venting systems that are no longer adequate, when switching to condensing heating equipment. Offering incentives for the newly emerging technology of natural gas-powered heat pumps provides customers the ability to heat their homes with the highest efficiency available in natural gas space heating. The program addresses water heating savings by offering incentives for ENERGY STAR® tankless water heaters. Gas fireplace inserts have

	become increasingly popular in Columbia Gas's service territory. Because of this, Columbia Gas is offering an incentive for customers to install a more efficient system. Incentives will be given to qualifying units achieving 70% efficiency or greater. The baseline efficiency for these fireplace inserts is 60%. Columbia Gas will also offer incentives for boiler reset controls. These controls will be eligible on residential boilers that currently do not have a reset control that is controlling the feed water temperature based on the outdoor temperature. To better serve multi-family customers in Columbia Gas's territory an incentive will be given for SPVUs. These units are the most popular space heating method in multi-family buildings. SPVUs do not have an ENERGY STAR® certification category, therefore, incentives will be given to qualifying units achieving 94% AFUE or greater. The baseline efficiency for SPVUs is 80%. Finally, the program addresses long-term savings by offering incentives for customers to upgrade the performance of their building shell through insulation and air sealing.
Financial Incentives	Incentives were designed to be in line with other offerings in the region and/or cover approximately two-thirds of the incremental cost of the measure. The table below lists the proposed incentive schedule. <i>Proposed Residential Prescriptive Program Rebates (Nominal)</i>

	Equipment	Minimum Efficiency	Proposed Incentive	Maximum Incentive
	Smart Thermostat	ENERGY STAR®	\$50	\$100
	Furnace	ENERGY STAR®	\$400	\$500
	Boiler	94+ AFUE	\$1,000	\$1,500
	Combi Boiler	94+ AFUE	\$1,200	\$1,800
	Tankless Water Heater	ENERGY STAR®	\$400	\$500
	Gas Heat Pump (Furnace Baseline)	Gas Heat Pump Forced Air	\$2,000	\$5,000
	Gas Heat Pump (Boiler Baseline)	Gas Heat Pump Air to Water	\$2,000	\$5,000
	Insulation and Air Sealing	N/A	25% Cost (\$2,500 Cap)	\$2,500
	Boiler Reset Controls	N/A	\$300	\$500
	Fireplace Inserts	70% Fe	\$150	\$200
	SPVU	94+ AFUE	\$400	\$500
	All equipment besides the Wi-Fi thermostat must be powered by natural gas. Insulation and Air Sealing customers must have natural gas as their heat source.			
Marketing Approach	The RP program may be marketed through inclusion on Columbia's website and through social media, as well as through bill inserts and other media messaging. The main way that many customers will hear about the RP Program is through paid search efforts, bill inserts and targeted customer emails.			

	Outreach to HVAC contractors, weatherization contractors, and plumbers will also play a role. Incentives will help these contractors sell jobs and provide their customers with higher levels of service. To further work with trade allies Columbia Gas <i>may</i> consider efforts such as cobranding and potentially assigning incentives to contractors will provide trade allies with even more tools to move customers to higher efficiency levels. Last, to better serve moderate income customers, Columbia Gas plans to braid these incentives with the existing Columbia Gas Audits and Rebates Program that is operated as part of the Company's Universal Service Programs. This incentive braiding will enable contractors in that program to offer more substantial retrofit opportunities by extending the budget per household.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> All applications will require proof of purchase and a valid Columbia Gas account number. Rebates received as an instant rebate via a qualified participating contractor or equipment distributor will be accompanied by an invoice showing the point-of-sale discount passed on to the customer. The rebate processor will verify that the equipment is eligible for the rebate based on the model number or the Air-Conditioning Heating and Refrigeration Institute (AHRI) number or through the Energy Star ® certified product list before issuing any rebate. The program's rebate processor will maintain a real-time database of rebate activity, which will be periodically reviewed by Columbia Gas and stored separately for long-term purposes. There will be inspections of approximately five percent (5%) of non-thermostat equipment rebates and approximately one percent (1%) of Wi-Fi thermostat rebates to obtain a statistically significant sample

	of activity. The inspection will consist of verifying that the rebated equipment is installed and operational and conclude with a short informational interview with the participant. Virtual inspections will be explored to reduce program costs and increase inspection rates. <u>Evaluations</u> A third-party vendor will evaluate the program's process and impacts after sufficient participation has occurred in the third year of the Plan.
Program Administration	<u>Rebate Processing and Inspection</u> The rebate processor will accept customer applications, track and verify application information, notify the customer of any issues, maintain a call center, and report results to Columbia Gas. The rebate processor may also be responsible for other programs to streamline portfolio management. The rebate processor will also be responsible for inspections. <u>Marketing and Outreach</u> Columbia Gas and their vendors will handle marketing and outreach for the RP program. <u>Evaluator</u> A third-party evaluator will be retained to perform evaluations.

2.2 Online Audit Kit

Objective	The Online Audit Kit (OAK) Program is designed to provide residential customers with information on how to improve the efficiency of their homes along with free, targeted energy savings kits. The program also provides a way for customers to engage with Columbia Gas and learn about the RP Program.				
Eligible Rate Class	RSD/RSS				
Cost Effectiveness	Three-Year Cost-Effectiveness Results (2025\$)				
	CE Test	PV Benefits	PV Costs	PV Net	BCR
	TRC Test	\$8,852,798	\$1,532,931	\$7,319,867	5.78
	Gas Admin Test	\$3,004,475	\$1,532,931	\$1,471,544	1.96
Savings Projections	Three-Year Savings Projections				
	First Year Savings	2026	2027	2028	2026 - 2028
	Natural Gas (Dth)	10,914	12,607	14,299	37,820
	Electric Energy (MWh)	0.0	0.0	0.0	0.0
	Peak Demand (kW)	0.0	0.0	0.0	0.0
	Water (Million Gallons)	14.4	16.7	18.9	50.1
	Lifetime Savings	2026	2027	2028	2026 - 2028
	Natural Gas (Dth)	124,541	143,835	163,130	431,506
	Electric Energy (MWh)	0.0	0.0	0.0	0.0
	Water (Million Gallons)	144.5	166.9	189.4	500.8

Budget Projections	Three-Year Budgets (Nominal)				
	Costs by Category	2026	2027	2028	2026 – 2028
	Customer Incentives	\$206,700	\$238,800	\$270,900	\$716,400
	Administration	\$234,000	\$261,000	\$288,000	\$783,000
	Marketing	\$44,000	\$48,500	\$53,000	\$145,000
	Inspections	\$0	\$0	\$0	\$0
	Evaluation	\$25,000	\$0	\$25,000	\$50,000
	Total	\$509,700	\$548,300	\$636,900	\$1,694,900
Participation Projections	Three-Year Participation Projections				
	Projected Kits	2026	2027	2028	2026 - 2028
	Water Heating Kit	4,500	5,200	5,900	15,600
	Space Heating Kit	1,300	1,500	1,700	4,500
	Total	5,800	6,700	7,600	20,100
Program Design	The OAK Program provides a way for customers to undergo an online audit of their home, which will result in a customized set of recommendations. The customer will then be eligible to receive up to two targeted energy saving kits, shipped to their home at no cost. The first kit is for customers who use natural gas for water heating, and the second kit is for customers who utilize natural gas to heat their homes. Participating customers will also be referred to the RP program incentives if appropriate.				
Target Market and End Uses	There will be two kits available for customers. The water heating kit will include measures such as high-efficiency showerheads and low-flow faucet aerators. The space heating kit will include low-cost				

	measures such as outlet and light switch gaskets, caulk, and foam sealant along with instructions on effective installation.
Financial Incentives	Kits will be provided at no cost to the customer.
Marketing Approach	The OAK program will be marketed through bill inserts, social media, and on Columbia Gas' website. Other outreach efforts may include email, radio, and print advertisements. The program will also share information about Columbia's other Energy Efficiency Programs.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> Columbia Gas will perform a survey of participants every year to determine installation rates for energy saving kits and assess customers satisfaction with program recommendations. <u>Evaluations</u> The program will undergo a process and impact evaluation in the third year once sufficient time has passed for the program to achieve meaningful participation.
Program Administration	<u>Online Audit and Kit Providers</u> Columbia Gas will hire vendors to provide an online audit solution and package and send energy saving kits to customers. <u>Marketing and Outreach</u> Columbia Gas and their vendors will handle marketing and outreach for the program.

	<u>Evaluator</u> A third-party evaluator will be retained to perform annual participant surveys and regular program evaluations.

2.3 Small Commercial Program

Objective	The Small Commercial (SC) program is designed to overcome market barriers to energy efficient space and water heating equipment and building shell upgrades in the small commercial sector through rebates and customer awareness. The program's objective is to encourage business owners to install the most efficient natural gas heating and process technologies available when replacing older, less efficient equipment and to make their building more efficient through the installation of insulation and air sealing measures to their building shell. The program also aims to strengthen Columbia Gas' relationship with HVAC contractors, suppliers, and other trade allies.				
Eligible Rate Class	SGSS1, SCD1, SGDS1, SGSS2, SCD2, SGDS2				
Cost Effectiveness	<i>Three-Year Cost-Effectiveness Results (2025\$)</i>				
	CE Test	PV Benefits	PV Costs	PV Net	BCR
	TRC Test	\$4,670,353	\$2,600,636	\$2,069,717	1.80
	Gas Admin Test	\$4,546,528	\$1,366,987	\$3,179,541	3.33
Savings Projections	<i>Three-Year Savings Projections</i>				
	First Year Savings	2026	2027	2028	2026 - 2028

	Natural Gas (Dth)	7,889	11,586	13,123	32,598
	Electric Energy (MWh)	18.7	33.5	39.7	91.9
	Peak Demand (kW)	2.3	4.2	5.0	11.5
	Water (Million Gallons)	0.2	0.2	0.2	0.6
	Lifetime Savings	2026	2027	2028	2026 - 2028
	Natural Gas (Dth)	151,033	188,733	204,113	543,880
	Electric Energy (MWh)	193.5	341.3	403.6	938.4
	Water (Million Gallons)	2.4	2.4	2.4	7.1
Budget Projections	Three-Year Budgets (Nominal)				
	Costs by Category	2026	2027	2028	2026 - 2028
	Customer Incentives	\$223,688	\$328,333	\$370,833	\$922,854
	Administration	\$146,650	\$111,025	\$112,950	\$370,625
	Marketing	\$50,950	\$31,575	\$31,850	\$114,375
	Inspections	\$10,250	\$16,500	\$19,250	\$46,000
	Evaluation	\$0	\$0	\$60,000	\$60,000
	Total	\$431,538	\$487,433	\$594,883	\$1,513,854
	Participation Projections	Three-Year Participation Projections			
Projected Units		2026	2027	2028	2026 - 2028
Commercial Boilers – ENERGY STAR		10	10	10	30
Commercial Water Heaters – ENERGY STAR		15	20	20	55
Steam Traps		25	40	50	115
Commercial Fryers – ENERGY STAR		5	5	5	15
Commercial Griddles – ENERGY STAR		5	5	5	15

	Commercial Dishwasher – ENERGY STAR	5	5	5	15
	SPVUs	15	25	30	70
	Advanced Rooftop Controls	100	195	235	530
	Insulation and Air Sealing	10	10	10	30
	Total	190	315	370	875
Program Design	The SC Program offers rebates for qualifying insulation and air sealing project, commercial-sized space and water heating equipment and controls, process equipment such as steam traps, and commercial kitchen equipment. Customers will have a contractor install the measure and receive a rebate to offset some of the incremental cost of the higher efficiency equipment. Customers will be encouraged to process rebates through an online portal but may also submit a paper application through the mail. If program funds begin to run low, incentive levels may be lowered, or equipment removed from the program if additional budget adjustments cannot be made. Columbia Gas will aim to provide as little interruption to customers as possible due to such adjustments. Columbia Gas will continue to examine other equipment for potential inclusion in the program, as well as the relative market adoption of equipment already receiving incentives.				
Target Market and End Uses	The SC Program will serve the small business and small commercial market such as houses of worship, office buildings, restaurants, retail stores, laundry facilities, schools, and government buildings. Customers in this sector that use natural gas for space heating, water heating, and process heating are expected to be the largest end use target for the program.				

Financial Incentives	Incentives were designed to be in line with other offerings in the region and/or cover approximately two-thirds of the incremental cost of the measure. The table below lists the proposed incentive schedule.			
	<i>Proposed Residential Prescriptive Program Rebates (Nominal)</i>			
	Equipment	Minimum Efficiency	Proposed Incentive	Maximum Incentive
	Commercial Boilers	ENERGY STAR®	\$2,000+(\$2/MBH)	\$2,000+(\$3/MBH)
	Commercial Water Heater	ENERGY STAR®	\$4/MBH	\$5/MBH
	Steam Traps	N/A	\$50	\$75
	Commercial Fryer	ENERGY STAR®	\$750	\$800
	Commercial Griddle	ENERGY STAR®	\$400	\$500
	Commercial Dishwasher	ENERGY STAR®	\$700	\$800
	SPVU	94+AFUE	\$400	\$500
	Advanced Roof Controls	N/A	\$1,000	\$1,100
	Insulation and Air Sealing	N/A	25% Cost (\$2,500 Cap)	\$2,500
	All equipment besides the Wi-Fi thermostat must be powered by natural gas. Insulation and Air Sealing customers must have natural gas as their heat source. Small Commercial customers may also take advantage of the same energy efficiency measures as offered through the RP.			

Marketing Approach	The SC Program marketing approach focuses on targeted outreach to trade allies and supply houses, as well as regular communication to end-use customers and various chambers of commerce. Columbia Gas will promote the program through its existing energy efficiency website and through other marketing activities.
Evaluation, Measurement, and Verification	<u>Quality Assurance</u> All applications will require proof of purchase and a valid Columbia Gas account number. Rebates may be processed where an application is submitted by the account owner with the required documentation (paid in full invoice with equipment/measure details) or the customer could receive an instant rebate on the qualified contractor or equipment distributor's invoice. The rebate processor will verify that the equipment is eligible for the rebate based on the model number or the Air-Conditioning Heating and Refrigeration Institute (AHRI) number or the product listing on the Energy Star® certified products list before issuing any rebate. The program's rebate processor will maintain a real-time database of rebate activity, which will be periodically reviewed by Columbia Gas and stored separately for long-term purposes. There will be inspections of approximately five percent (5%) of rebates to obtain a statistically significant sample of activity. The inspection will consist of verifying that the rebated equipment is installed and operational and conclude with a short informational interview with the participant. Virtual inspections will be explored to reduce program costs and increase inspection rates. <u>Evaluations</u>

	A third-party vendor will evaluate the program's process and impacts after sufficient participation has occurred in the third year of the Plan.
Program Administration	<u>Rebate Processing and Inspection</u> The rebate processor will accept customer applications, track and verify application information, notify the customer of any issues, maintain a call center, and report results to Columbia Gas. The rebate processor may also be responsible for other programs to streamline portfolio management. The rebate processor will also be responsible for inspections. <u>Marketing and Outreach</u> Columbia Gas and their vendors will handle marketing and outreach for the RP program. <u>Evaluator</u> A third-party evaluator will be retained to perform evaluations.

3 Appendices

3.1 Avoided Cost Tables

Gas Avoided Costs (2025\$/Dth)

Year	Base	Space Heating	Domestic Hot Water
2026	5.19	11.55	6.78
2027	4.93	11.33	6.53
2028	4.72	11.20	6.34
2029	4.50	11.05	6.14
2030	5.15	11.71	6.79
2031	5.27	11.87	6.92
2032	5.32	11.99	6.99
2033	5.42	12.15	7.10
2034	5.43	12.29	7.14
2035	5.49	12.52	7.24
2036	5.51	12.63	7.29
2037	5.55	12.74	7.35
2038	5.59	12.86	7.41
2039	5.61	12.96	7.45
2040	5.68	13.11	7.53
2041	5.70	13.22	7.58
2042	5.70	13.31	7.60
2043	5.73	13.42	7.65
2044	5.67	13.47	7.62
2045	5.66	13.55	7.63
2046	5.67	13.65	7.67
2047	5.68	13.76	7.70
2048	5.74	13.91	7.78
2049	5.73	14.01	7.80
2050	5.75	14.13	7.84
2051	5.80	14.28	7.92
2052	5.85	14.44	8.00
2053	5.90	14.60	8.08

Other Resource Avoided Costs (2025\$)

Year	All-Year Energy (\$/kWh)	Generation Capacity (\$/kW-yr)	T&D (\$/kW-yr)	Water (\$/gal)
2026	0.0356	57.979	57.231	0.0143
2027	0.0369	57.981	57.232	0.0143
2028	0.0385	57.979	57.232	0.0143
2029	0.0397	57.978	57.232	0.0143
2030	0.0404	57.979	57.231	0.0143
2031	0.0413	57.977	57.229	0.0143
2032	0.0429	57.979	57.232	0.0143
2033	0.0438	57.979	57.228	0.0143
2034	0.0446	57.976	57.233	0.0143
2035	0.0440	57.980	57.229	0.0143
2036	0.0436	57.975	57.229	0.0143
2037	0.0439	57.979	57.233	0.0143
2038	0.0441	57.977	57.232	0.0143
2039	0.0440	57.977	57.232	0.0143
2040	0.0442	57.976	57.229	0.0143
2041	0.0444	57.977	57.230	0.0143
2042	0.0444	57.977	57.230	0.0143
2043	0.0444	57.977	57.230	0.0143
2044	0.0444	57.977	57.230	0.0143
2045	0.0444	57.977	57.230	0.0143
2046	0.0444	57.977	57.230	0.0143
2047	0.0444	57.977	57.230	0.0143
2048	0.0444	57.977	57.230	0.0143
2049	0.0444	57.977	57.230	0.0143
2050	0.0444	57.977	57.230	0.0143
2051	0.0444	57.977	57.230	0.0143
2052	0.0444	57.977	57.230	0.0143
2053	0.0444	57.977	57.231	0.0143

3.2 Detailed Measure Assumptions

Measure Name	Costs		Savings				
	Incentive	Incr. Cost	Lifetime (Yrs)	Dth	kWh	kW	Water (Gal)
Residential Prescriptive Program							
Furnace - ENERGY STAR	\$400.00	\$758.40	20	13.99	0	0	0
Boiler - 94+ AFUE	\$1,000.00	\$1,785.00	25	12.83	0	0	0
Combi Boiler - 94+ AFUE	\$1,200.00	\$2,526.18	25	22.72	0	0	0
Wifi Thermostat - ENERGY STAR	\$100.00	\$150.00	11	4.52	73	0.01	0
Tankless Water Heater - ENERGY STAR	\$400.00	\$592.85	20	9.18	0	0	0
Gas Heat Pump (Furnace)	\$2,000.00	\$17,195.75	15	40.46	0	0	0
Gas Heat Pump (Boiler)	\$2,000.00	\$14,007.50	15	36.09	0	0	0
Insulation & Air Sealing	\$925.00	\$3,700.00	30	12.50	176.74	0.1361	0
Boiler Reset Controls	\$300.00	\$636.72	16	8.97	0	0	0
Fireplace Inserts	\$150.00	\$342.29	20	2.10	0	0	0
SPVUs	\$400.00	\$962.02	20	5.67	0	0	0
Online Audit Kit Program							
Web Faucet Aerator - Kitchen	\$2.00	\$2.00	10	0.51	0	0	941
Web Faucet Aerator - Bathroom	\$1.00	\$1.00	10	0.11	0	0	201
Web High Efficiency Showerhead	\$5.00	\$5.00	10	0.51	0	0	934
Web Switch/Outlet Cover	\$2.50	\$2.50	15	1.64	0	0	-
Web Caulk	\$3.00	\$3.00	15	0.37	0	0	-
Web Foam Sealant	\$6.00	\$6.00	15	0.37	0	0	-
Water Heating Kit	\$25.00	\$25.00	1	-	0	0	-
Space Heating Kit	\$12.50	\$12.50	1	-	0	0	-

Small Commercial Program

Commercial Boilers	\$3,200.00	\$7,242.47	25	137.42	0	0	0
Commercial Water Heaters	\$979.17	\$1,642.15	15	23.28	0	0	0
Steam Traps	\$50.00	\$106.41	6	6.88	0	0	0
Commercial Fryers	\$750.00	\$922.52	12	53.31	0	0	0
Commercial Griddles	\$400.00	\$934.76	12	17.16	0	0	0
Commercial Dishwashers	\$700.00	\$1,753.28	12	31.29	630.306	0.08059	39631.7
SPVUs	\$400.00	\$962.02	20	5.67	0	0	0
Advanced Rooftop Controls	\$1,000.00	\$2,032.85	10	36.00	155.65	0.01934	0
Insulation and Airsealing	\$6,050.00	\$24,200.00	37	180.00	0	0	0

3.3 Detailed Program and Portfolio Cost-effectiveness

Energy Efficiency Programs' Cost Effectiveness over Three-Year Portfolio (2025\$)

	Total Resource			Gas Energy System		
Program ID	Present Value		PV of Net Benefits [4]	Present Value		PV of Net Benefits [12]
	Benefit [2]	Cost [3]		Benefit [10]	Cost [11]	
Portfolio Total	\$28,605,309	\$11,482,561	\$17,122,749	\$22,197,897	\$7,142,051	\$15,055,846
Non-Measure Costs		\$3,249,664			\$3,249,664	
Total Measure Costs	\$28,605,309	\$8,232,897	\$20,372,413	\$22,197,897	\$3,892,387	\$18,305,510
Program						
Residential Prescriptive Program						
Program Total	\$15,082,158	\$6,514,710	\$8,567,448	\$14,646,893	\$3,407,849	\$11,239,044
Non-Measure Costs		\$994,115			\$994,115	
Total Measure Costs	\$15,082,158	\$5,520,595	\$9,561,563	\$14,646,893	\$2,413,734	\$12,233,159
Online Audit Kit Program						
Program Total	\$8,852,798	\$1,532,931	\$7,319,867	\$3,004,475	\$1,532,931	\$1,471,544
Non-Measure Costs		\$885,462			\$885,462	
Total Measure Costs	\$8,852,798	\$647,469	\$8,205,329	\$3,004,475	\$647,469	\$2,357,006
Portfolio Wide Costs						
Program Total	-	\$834,284	\$(834,284)	-	\$834,284	\$(834,284)
Non-Measure Costs		\$834,284			\$834,284	
Total Measure Costs	-	-	-	-	-	-
Small Commercial Program						
Program Total	\$4,670,353	\$2,600,636	\$2,069,717	\$4,546,528	\$1,366,987	\$3,179,541
Non-Measure Costs		\$535,804			\$535,804	
Total Measure Costs	\$4,670,353	\$2,064,832	\$2,605,521	\$4,546,528	\$831,184	\$3,715,345

Technical Reference Manual

Measure Savings Algorithms

Columbia Gas of Pennsylvania

February 19, 2024

Prepared by:



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Prepared by: Green Energy Economics Group, Inc.

1 Cross-Sector TRM Issues

1.1 Establishing Baselines

The savings methods and assumptions can differ substantially based on the program delivery mechanism for each measure type. Within each of the measure protocols in the TRM, there is a definition for the measure's baseline efficiency, a critical input into the savings calculations. Most measures will fall into one of two categories, each with a baseline that is most commonly used:

- One for market-driven choices – often called “lost opportunity” and either replacing equipment that has failed (replace on burnout) or new installations (new construction)
- One for discretionary installations – either early replacement or retrofit

For all new construction (NC) and replace on burnout (ROB) scenarios, the baseline is typically a jurisdictional code or a national standard; however, there may be cases where a market baseline is appropriate. In these scenarios, the Commission has a preference for codes and standards as it is too expensive and time consuming to conduct annual market baseline and characterization research. Additionally, the TRM provides estimates for gross energy savings only, whereas net savings “...include the effects of free-ridership, spillover, and induced market effects.”

For discretionary installation scenarios, the baseline is typically the existing equipment efficiency, but in the case of early replacement (EREP), at some point the savings calculations must incorporate changes to the baseline for new installations (e.g., code or market changes) to account for eventual natural replacement of the equipment. This approach encourages residential and business consumers to replace working inefficient equipment and appliances with new high-efficiency products rather than taking no action to upgrade or only replacing them with new standard-efficiency products.

All baselines are designed to reflect current market practices that are updated periodically to reflect upgrades in federal equipment standards, building code, or information from evaluation results. Specifically for commercial and industrial measures, Pennsylvania has adopted the 2015 International Energy Conservation Code (IECC) per 34 Pa. Code Section 403.21, effective October 1, 2018. Per Section 401.2 of IECC 2015, commercial buildings must comply with either “[t]he requirements of ANSI/ASHRAE/IESNA Standard 90.1[-2013]” or comply with the requirements outlined in IECC 2015 Chapter 4. In accordance with IECC 2015, commercial protocols relying on code standards as the baseline condition may refer to either IECC 2015 or ASHRAE 90.1-2013 per the program design.

The baseline estimates used in the TRM are based on applicable federal standards, or are documented in baseline studies or other market information. This TRM reflects the most up-to-date codes, practices, and market transformation effects. The measures herein include, where appropriate, schedules for the implementation of Federal standards to coincide with the beginning of a program year. These implementation schedules apply to measures where the Federal standard is considered the baseline, as described herein or otherwise required by law. In cases where the ENERGY STAR criterion is considered the eligibility requirement and the existing ENERGY STAR Product Specification Version expires in a given year, the new ENERGY STAR Product Specification Version will become the eligibility requirement at the start of the next consecutive program year.

The combined effect of measure retention and persistence is the ability of installed measures to maintain the initial level of energy savings or generation over the measure life. If the measure is subject to a reduction in savings or generation over time, the reduction in retention or persistence is accounted for using factors in the calculation of resource savings.

2 Residential Time of Replacement Market

2.1 Space Heating End Use

2.1.1 Efficient Space Heating System

Unique Measure Code(s): TBD

Draft date: 2/19/24

Effective date: TBD

End date: TBD

Measure Description

This measure applies to residential-sized gas furnaces, boilers, and gas heat pumps purchased at the time of natural replacement. A qualifying furnace or boiler must meet minimum efficiency requirements (AFUE).

Definition of Baseline Condition

The efficiency levels of the gas-fired furnaces or boilers that would have been purchased absent this or another DSM program are shown in the following table. The baseline for a gas heat pump is the type of equipment currently in place and being replaced.

Equipment Type	Baseline AFUE
Gas Furnace	80%
Gas Boiler	84%

Definition of Efficient Condition

The installed gas furnace or boiler must have an AFUE greater than that shown in the table below. Efficient model minimum AFUE requirements are detailed below.

Equipment Type	Minimum AFUE
Gas Furnace	95%
Gas Boiler	94%
Gas Heat Pump	>100%

Gas Savings Algorithms

MMBtu savings are realized due to the increase in AFUE of the new equipment. MMBtu savings vary by equipment type due to differences in model specific baseline AFUE and high efficiency AFUE percentages. Savings are calculated from the baseline new unit to the installed efficient unit.

$$\text{Annual Gas Savings (MMBtu)} = \frac{\text{Capacity}_{out}}{1,000} \times \left(\frac{1}{AFUE_{Base}} - \frac{1}{AFUE_{Eff}} \right) \times EFLH_{Heat}$$

Where:

Capacity_{Out} = Output capacity of equipment to be installed (kBtu/hr)
1,000 = Conversion from kBtu to MMBtu
AFUE_{Base} = Efficiency of new baseline equipment (Annual Fuel Utilization Efficiency)
AFUE_{Eff} = Efficiency of new equipment
EFLH_{Heat} = Equivalent Full Load Heating Hours (Refer to EFLH table by climate zone in

References Section)

Electric Savings Algorithms

Energy Savings

$$\Delta kWh = 0 \text{ kWh}$$

Demand Savings

$$\Delta kW = 0 \text{ kW}$$

Where:

ΔkWh = Gross customer annual kWh savings for the measure.
 ΔkW = Gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
Gas Furnace	0%	0%
Gas Furnace with ECM Fan	0%	0%
Gas Boiler	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
Gas Furnaces	20
Gas Boilers	25
Gas Heat Pump	15

Sources: Lifetime estimates used by Efficiency Vermont, PGW and UGI for furnaces and boilers. Gas heat pump lifetime from Illinois TRM, Version 11.0, Volume 2, p 575.

Water Savings

There are no water savings for this measure.

2.1.2 Wi-Fi Thermostat – ENERGY STAR®

Unique Measure Code(s): TBD

Draft date: 2/19/24

Effective date: TBD

End date: TBD

Measure Description

This is an ENERGY STAR® WiFi thermostat controlling a residential-sized gas furnace or boiler.

Definition of Baseline Condition

The baseline is a manual thermostat where each temperature setting change requires human intervention or a conventional programmable.

Definition of Efficient Condition

The efficient thermostat is one that is WiFi enabled, ENERGY STAR® certified and can be programmed to automatically increase or lower the temperature setting at different times of the day and week.

Gas Savings Algorithms

$$\text{Annual Gas Savings (MMBtu)} = SH_{pre} \times ESF$$

Where:

SH_{pre}	=	Space Heat MMBtu gas usage with manual thermostat = 70.6 ¹
ESF	=	Percentage savings from WiFi thermostat compared to non-WiFi connected thermostat. See table below by installation method.

¹ Space-heat usage assumption from examination of Columbia Gas PA residential usage by month.

Heating Energy Savings Factors (ESF)

Program Type	Baseline	Air Source Heat Pump	Furnace/Boiler Heating (Electric or Fossil)
Upstream buy-down (Customer Self-Installation)	Unknown Mix Default	6.4% ^a	6.4% ^a
Customer Self-Installation with Education	Unknown Mix Default	7.9% ^b	7.9% ^b
Professional Installation	Manual	11.5% ^c	11.5% ^c
	Conventional programmable	7.9% ^d	7.9% ^d

^a Average of heating estimates from two studies.

^b Heating savings are based on average of savings from unknown mix default with customer self-installation and average of professional installation savings from manual and programmable thermostats. In this case, $7.9\% = ((11.5\% \times 0.42 + 7.9\% \times 0.58) + 6.4\%) / 2$

^c Average of four heating savings estimates from four studies.

^d The ESF value for a is applied here as an estimate until information becomes available showing different savings incented through a direct install program.

Source for table values: Act 129 Phase IV TRM.

Electric Savings Algorithms

If the type of air conditioning is known, then use the appropriate algorithm below. If the type or existence of air-conditioning is not known, then assume that 45% have central air-conditioning and estimate the cooling savings as 45% of a house with central air conditioning.²

Reduced furnace fan or boiler circulator pump usage is also likely to occur and provide electricity savings during both the heating and cooling seasons, but these auxiliary savings are not accounted for in the following algorithms.

Energy Savings

$$\Delta \text{kWh} = \Delta \text{kWh}_{\text{Aux}} + \Delta \text{kWh}_{\text{Cool}}$$

$$\Delta \text{kWh}_{\text{Aux}} = \text{Furnace Fan kWh savings}$$

$$\begin{aligned} \Delta \text{kWh}_{\text{Cool}} &= 0 \text{ kWh if house has no air conditioning} \\ &= \Delta \text{kWh}_{\text{CAC}} \text{ if house has central air conditioning} \\ &= 0 \text{ if house has room air conditioning} \\ &= 45\% \times \Delta \text{kWh}_{\text{CAC}} \text{ if no information about air conditioner} \end{aligned}$$

² Percentage of houses with central air-conditioning from 2009 RECS data.

Deemed Savings ΔkWh

Program Type	Baseline	Fossil Fuel Furnace (Fan Only) ΔkWh_{Aux}	CAC Cooling ΔkWh_{CAC}
Upstream buy-down (Customer Self-Installation)	Unknown Mix Default	48	77
Customer Self-Installation with Education	Unknown Mix Default	60	120
Professional Installation	Manual	87	182
	Conventional programmable	60	150

Source: Act 129 Phase IV TRM.

Demand Savings

ΔkW
 = 0 kW if house has no air conditioning
 = ΔkW_{CAC} if house has central air conditioning
 = 0 if house has room air conditioning
 = $45\% \times \Delta kW_{CAC}$ if no information about air conditioner
 = 0.0130 kW default

Deemed Savings ΔkW

Program Type	Baseline	ASHP Cooling	CAC Cooling ΔkW_{CAC}
Upstream buy-down (Customer Self-Installation)	Unknown Mix Default	0.0269	0.0289
Customer Self-Installation with Education	Unknown Mix Default	0.0418	0.0450
Professional Installation	Manual	0.0633	0.0680
	Conventional programmable	0.0521	0.0560

Source: Act 129 Phase IV TRM.

Where:

ΔkWh = gross customer annual kWh savings for the measure.
 ΔkW = gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
WiFi Thermostat	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
WiFi Thermostat	11

Source: August 2019 Act 129 TRM, Volume 2, p.47.

Water Savings

There are no water savings for this measure.

2.2 Water Heating End Use

2.2.1 Tankless Water Heater

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This measure is an on-demand gas water heater.

Definition of Baseline Condition

The efficiency levels of the gas-fired stand-alone storage water heater that would have been purchased absent this or another DSM program are shown in the following table.

Equipment Type	Usage Draw Pattern	Baseline UEF ³
Gas Stand-alone Storage Water Heater	Very Small	0.27
Gas Stand-alone Storage Water Heater	Low	0.52
Gas Stand-alone Storage Water Heater	Medium	0.58
Gas Stand-alone Storage Water Heater	High	0.64

Baseline usage draw pattern is established by the capacity of the installed tankless water heater, using the table below:

³ Based on the federal standard for residential gas-fired water heater as of June 2017 and assumed typical 40 gallon storage.
<https://www.law.cornell.edu/cfr/text/10/430.32>

Usage Draw Pattern	Max GPM	Daily Volume in Gallons (V)
Very Small	$0 \leq \text{GPM} < 1.7$	10
Low	$1.7 \leq \text{GPM} < 2.8$	38
Medium	$2.8 \leq \text{GPM} < 4.0$	55
High	$4.0 \leq \text{GPM}$	84

If the tankless water heater capacity is not available, assume medium usage draw pattern.

Definition of Efficient Condition

The installed tankless water heater must have an UEF greater than that shown in the table below. Efficient model minimum UEF requirements are detailed below.

Equipment Type	Minimum UEF
Gas Tankless Water Heater	0.87

Gas Savings Algorithms

The following formula for gas savings is based on the DOE test procedure for water heaters⁴.

$$\text{Annual Gas Savings (MMBtu)} = \frac{\left(\frac{1}{UEF_{Base}} - \frac{1}{UEF_{Eff}} \right) \times V \times \rho \times c_p \times 67 \times 365}{1,000,000}$$

Where:

UEF_{Base}	=	Uniform Energy Factor of baseline water heater based on usage draw pattern
UEF_{Eff}	=	Uniform Energy Factor of efficient water heater
V	=	Daily volume of hot water usage in gallons. See table in baseline section. If usage draw pattern is unknown, assume medium (55 gallons/day).
ρ	=	Water density at 125°F (8.24 lb/gal)
c_p	=	Specific heat of water (1.00 Btu/lb °F)
67	=	°F temperature rise between inlet and outlet of water heater
365	=	Days per year
1,000,000	=	Btu per MMBtu

Electric Savings Algorithms

There are no electric savings from this measure.

Energy Savings

$$\Delta \text{kWh} = 0 \text{ kWh}$$

Demand Savings

$$\Delta \text{kW} = 0 \text{ kW}$$

⁴ 10 CFR Appendix E to Subpart B of Part 430, Uniform Test Method for Measuring the Energy Consumption of Water Heaters

Where:

ΔkWh = gross customer annual kWh savings for the measure.
 ΔkW = gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
Tankless Water Heater	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
Tankless Water Heater	20

Source: Energy Star Residential Water Heaters: Final Criteria Analysis, April 1, 2008, p. 10.

Water Savings

There are no water savings for this measure.

2.3 Combined Space and Domestic Hot Water Usage

2.3.1 Combination Boiler - Space Heating and DHW

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This measure applies to residential-sized combination boilers purchased at the time of natural replacement. These are integrated boilers that provide hot water for space heating and on-demand domestic hot water and have minimal or no hot water storage. A qualifying combination boiler (combi boiler) must meet minimum efficiency requirements (AFUE).

Definition of Baseline Condition

The efficiency levels of the gas-fired boiler and stand-alone storage water heater that would have been purchased absent this or another DSM program are shown in the following table.

Equipment Type	Baseline ⁵
Gas Boiler	84% AFUE

Equipment Type	Usage Draw Pattern	Baseline UEF ⁶
Gas Stand-alone Storage Water Heater	Very Small	0.27
Gas Stand-alone Storage Water Heater	Low	0.52
Gas Stand-alone Storage Water Heater	Medium	0.58
Gas Stand-alone Storage Water Heater	High	0.64

Baseline usage draw pattern is established by the capacity of the water heater, using the table below:

Usage Draw Pattern	Max GPM	Daily Volume in Gallons (V)
Very Small	$0 \leq \text{GPM} < 1.7$	10
Low	$1.7 \leq \text{GPM} < 2.8$	38
Medium	$2.8 \leq \text{GPM} < 4.0$	55
High	$4.0 \leq \text{GPM}$	84

If the water heater capacity is not available, assume medium usage draw pattern.

Definition of Efficient Condition

The installed gas furnace or boiler must have an AFUE greater than that shown in the table below. Efficient model minimum AFUE requirements are detailed below.

Equipment Type	Minimum AFUE
Gas Combi Boiler	94% AFUE 0.94 UEF

Gas Savings Algorithms

MMBtu savings are realized due to the increase in AFUE of the new equipment. MMBtu savings vary by equipment type due to differences in model specific baseline AFUE and high efficiency AFUE percentages. Savings are calculated from the baseline new unit to the installed efficient unit.

$$\text{Annual Gas Savings (MMBtu)} = \text{Annual Gas Savings}_{SH} + \text{Annual Gas Savings}_{DHW}$$

$$\text{Annual Gas Savings}_{SH} = \frac{\text{Capacity}_{Out}}{1,000} \times \left(\frac{1}{AFUE_{Base}} - \frac{1}{AFUE_{Eff}} \right) \times EFLH_{Heat}$$

⁵ Existing residential boiler federal standard as of 10/1/2022.

⁶ Based on the federal standard for residential gas-fired water heater as of June 2017 and assumed typical 40 gallon storage.
<https://www.law.cornell.edu/cfr/text/10/430.32>

Where:

$Annual\ Gas\ Savings_{SH}$	=	Space heating annual gas savings (MMBtu)
$Annual\ Gas\ Savings_{DHW}$	=	Domestic Hot Water annual gas savings (MMBtu)
$Capacity_{Out}$	=	Output capacity of equipment to be installed (kBtu/hr)
1,000	=	Conversion from kBtu to MMBtu
$AFUE_{Base}$	=	Efficiency of new baseline equipment (Annual Fuel Utilization Efficiency)
$AFUE_{Eff}$	=	Efficiency of new equipment
$EFLH_{Heat}$	=	Equivalent Full Load Heating Hours (Refer to EFLH table by climate zone in References Section)

The following formula for DHW gas savings is based on the DOE test procedure for water heaters.

$$Annual\ Gas\ Savings_{DHW} = \frac{\left(\frac{1}{UEF_{Base}} - \frac{1}{UEF_{Eff}} \right) \times V \times \rho \times c_p \times 67 \times 365}{1,000,000}$$

Where:

UEF_{Base}	=	Uniform Energy Factor of baseline water heater. See UEF based on usage draw pattern in Baseline section above. If draw pattern cannot be established assume medium draw pattern.
UEF_{Eff}	=	Uniform Energy Factor of efficient combi boiler. Since the combi boiler has no or little storage, standby losses are assumed to be negligible and the UEF is assumed to be the same as the AFUE.
V	=	Daily volume of hot water usage in gallons. See table in baseline section. If usage draw pattern is unknown, assume medium (55 gallons/day).
ρ	=	Water density at 125°F (8.24 lb/gal)
c_p	=	Specific heat of water (1.00 Btu/lb °F)
67	=	°F temperature rise between inlet and outlet of water heater
365	=	Days per year
1,000,000	=	Btu per MMBtu

Electric Savings Algorithms

Energy Savings

$$\Delta kWh = 0\ kWh$$

Demand Savings

$$\Delta kW = 0\ kW$$

Where:

ΔkWh	=	Gross customer annual kWh savings for the measure.
ΔkW	=	Gross customer summer load kW savings for the measure.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
Gas Combi Boiler	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Equipment Type	Measure Lifetime
Gas Combi Boiler	20

Source: Same as lifetime estimate used for tankless water heater.

Water Savings

There are no water savings for this measure.

2.4 All End Uses

2.4.1 Custom Measure

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This measure applies to all residential time of replacement custom measures, not otherwise specified in this TRM.

Definition of Baseline Condition

The baseline represents the typical equipment that is installed without a DSM program. The efficiency level is based on the current Federal standards, or state and local building codes that are applicable.

Definition of Efficient Condition

The efficient measure is any equipment that uses less energy than the baseline equipment.

Gas Savings Algorithms

The generalized equation for a custom measure compares the baseline usage to the efficient usage.

$$\text{Annual Gas Savings (MMBtu)} = \text{BaselineUse} - \text{EfficientUse}$$

Where:

BaselineUse = The gas usage of baseline equipment or building.

EfficientUse = The gas usage of efficient equipment or building.

Electric Savings Algorithms

Energy Savings

$$\Delta kWh = BaselinekWh - EfficientkWh$$

Demand Savings

$$\Delta kW = BaselinekW - EfficientkW$$

Where:

ΔkWh = Gross customer annual kWh savings for the measure.

ΔkW = Gross customer summer load kW savings for the measure.

BaselinekWh = The electric kWh usage of baseline equipment or building.

EfficientkWh = The electric kWh usage of efficient equipment or building.

BaselinekW = The electric kW usage of baseline equipment or building.

EfficientkW = The electric kW usage of efficient equipment or building.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Equipment Type	Free Ridership	Spillover
Custom Measure	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Where available, custom measure lifetimes should be based on similar measures defined elsewhere in this TRM.

Water Savings

The water savings are the difference between the baseline and efficient equipment annual water usage in gallons.

3 Residential Early Replacement Market

3.1 Space Heating End Use

3.1.1 Kit Infiltration Reduction

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This involves decreasing the amount of air exchange between the inside of the house or unit and the outdoors using simple air sealing items included in kits mailed to customers.

Definition of Baseline Condition

The baseline is the house in its pre-treatment condition, with opportunities for infiltration reductions.

Definition of Efficient Condition

Any decrease in infiltration will reduce energy consumption compared to the pre-treated house.

Gas Savings Algorithms

$$\text{Annual Gas Savings (MMBtu)} = \text{Default Savings}$$

Where:

Default Savings = Deemed savings from kit air sealing measures. See table of default savings by measure.

Electric Savings Algorithms

Though there may be some electric cooling savings, however, no savings are currently assumed.

Default savings values for Kit Air Sealing Measures

Air Sealing Measure	MMBtu Savings	Source
Switch/Outlet Covers	1.64	Columbia Gas VA (CVA) savings assumption adjusted by HDD in Columbia Gas PA (CPA) territory relative to CVA HDD.
Caulk	0.37	CVA savings assumption adjusted by HDD in CPA territory relative to CVA HDD.
Foam Sealant	0.37	CVA savings assumption adjusted by HDD in CPA territory relative to CVA HDD.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Measure	Free Ridership	Spillover
Infiltration Reduction	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Measure	Measure Lifetime
Kit Infiltration Reduction	15

Source: Current assumption used by Columbia Gas VA.

Water Savings

There are no water savings for this measure.

3.1.2 Infiltration Reduction

Unique Measure Code(s): TBD

Draft date: 2/5/24

Effective date: TBD

End date: TBD

Measure Description

This involves decreasing the amount of air exchange between the inside of the house or unit and the outdoors without buffering from any adjacent unit(s) by sealing the sources of leaks, while maintaining minimum air exchange for air quality.

Definition of Baseline Condition

The baseline is the house in its pre-treatment condition, with opportunities for infiltration reductions.

Definition of Efficient Condition

Any decrease in infiltration will reduce energy consumption compared to the pre-treated house.

Gas Savings Algorithms

$$\text{Annual Gas Savings (MMBtu)} = \frac{HDD_t \times 24 \times (CFM50_{pre} - CFM50_{post})}{(21.5 \times AFUE \times 1,000,000)}$$

Where:

$HDD_t =$	Heating degree days at temperature t, where t=63°F if no programmable thermostat has been installed and t=62°F if a programmable thermostat has been installed. See the Reference Tables section at the end of this document for projected HDD.
24 =	hours/day
$CFM50_{pre} =$	CFM50 of building shell leakage as measured by a blower door test before treatment.
$CFM50_{post} =$	CFM50 of building shell leakage as measured by a blower door test after treatment.
21.5 =	factor to convert CFM50 value to Btu/hrF heat loss rate, calculated from hourly infiltration modeling ⁷
AFUE =	rated AFUE of heating system. If no rating is available then use the method described in the Efficient Space Heating System section for calculating the AFUE. The AFUE of replacement equipment should be used if the heating system replacement precedes the air sealing work.

Electric Savings Algorithms

If the type of air conditioning is known, then use the appropriate algorithm below. If the type or existence of air-conditioning is not known, then assume that 45% have air-conditioning and estimate the cooling savings as 45% of a house with central air conditioning.⁸

Reduced furnace fan or boiler circulator pump usage is also likely to occur and provide electricity savings during both the heating and cooling seasons.

Energy Savings

$$\Delta kWh = \Delta kWh_{Aux} + \Delta kWh_{Cool}$$

$$\Delta kWh_{Aux} = \text{Annual Gas Savings (MMBtu)} \times \text{Auxiliary}$$

$$\begin{aligned} \Delta kWh_{Cool} &= 0 \text{ kWh if house has no air conditioning} \\ &= \Delta kWh_{CAC} \text{ if house has central air conditioning} \\ &= \Delta kWh_{RAC} \text{ if house has room air conditioning} \\ &= 45\% \times \Delta kWh_{CAC} \text{ if no information about air conditioner} \end{aligned}$$

$$\begin{aligned} \Delta kWh_{CAC} &= \frac{CDD \times 24 \times DUA \times (CFM50_{pre} - CFM50_{post})}{\left(21.5 \times SEER_{CAC} \times 1000 \frac{W}{kW}\right)} \\ \Delta kWh_{RAC} &= \frac{CDD \times 24 \times DUA \times F_{Room AC} \times (CFM50_{pre} - CFM50_{post})}{\left(21.5 \times EER_{RAC} \times 1000 \frac{W}{kW}\right)} \end{aligned}$$

⁷ An hourly infiltration was calculated using a modified version of the LBL (a.k.a. Sherman-Grimsrud) infiltration model with a wind effect modification (EPRI RP 2034-40, Palmiter and Bond 1991) using Philadelphia TMY2 hourly weather data. This analysis result was then adjusted to account for an assumed party wall leakage fraction of 12% and an estimated 10% thermal regain from infiltration/exfiltration. The resulting value of 21.5 is consistent with statistical analyses of empirical data using CFM50 values and actual gas use and savings from CWP evaluations.

⁸ Percentage of houses with air-conditioning from UGI data.

Demand Savings

ΔkW = 0 kW if house has no air conditioning
 = ΔkW_{CAC} if house has central air conditioning
 = ΔkW_{RAC} if house has room air conditioning

$$\Delta kW_{CAC} = \frac{\Delta kWh_{CAC}}{EFLH_{cool}} \times CF_{CAC}$$

$$\Delta kW_{RAC} = \frac{\Delta kWh_{RAC}}{EFLH_{cool RAC}} \times CF_{RAC}$$

Where:

ΔkWh = gross customer annual kWh savings for the measure.

ΔkW = gross customer summer load kW savings for the measure.

Auxiliary = Heating system auxiliary usage per MMBTU consumption (5.02 From Vermont Technical Reference Manual)

CDD = Cooling Degree Days (Degrees F * Days). See the Reference Tables section at the end of this document for projected CDD.

DUA = Discretionary Use Adjustment to account for the fact that people do not always operate their air conditioning system when the outside temperature is greater than 65F.

SEER_{CAC} = Seasonal Energy Efficiency Ratio of existing home central air conditioner (Btu/W•hr) (See table below for default values if actual values are not available)

$\overline{EER}_{RAC}$ = Average Energy Efficiency Ratio of existing room air conditioner (Btu/W•hr) (See table below for default values if actual values are not available)

CF_{CAC} = Demand Coincidence Factor for central AC systems (See table below)

CF_{RAC} = Demand Coincidence Factor for Room AC systems (See table below)

EFLH_{cool} = Equivalent Full Load Cooling hours for Central AC and ASHP (Refer to EFLH table by climate zone in References Section)

EFLH_{cool RAC} = Equivalent Full Load Cooling hours for Room AC (Refer to EFLH table by climate zone in References Section)

F_{Room AC} = Adjustment factor to relate insulated area to area served by Room AC units

The default values for each term are shown in the table below.

Default values for algorithm terms, Ceiling/Attic and Wall Insulation

Term	Type	Value	Source
DUA	Fixed	0.75	OH TRM ⁹
SEER _{CAC}	Variable	Default values: Early Replacement = 10 Replace on Burnout = 13	PUC Technical Reference Manual
		Nameplate	Contractor Data Gathering
$\overline{EER}_{RAC}$	Variable	Default = 9.8	DOE Federal Test Procedure 10 CFR 430, Appendix F (Used in ES Calculator for baseline)
		Nameplate	Contractor Data Gathering
CF _{CAC}	Fixed	0.70	PUC Technical Reference Manual
CF _{RAC}	Fixed	0.58	PUC Technical Reference Manual
F _{Room,AC}	Fixed	0.38	Calculated ¹⁰

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Measure	Free Ridership	Spillover
Infiltration Reduction	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Measure	Measure Lifetime
Infiltration Reduction	20

Source: NYSDERDA Home Performance with Energy Star.

Water Savings

There are no water savings for this measure.

⁹ "State of Ohio Energy Efficiency Technical Reference Manual," prepared for the Public Utilities Commission of Ohio by Vermont Energy Investment Corporation. August 6, 2010.

¹⁰ From PECO baseline study, average home size = 2323 ft², average number of room AC units per home = 2.1. Average Room AC capacity = 10,000 BtuH per ENERGY STAR Room AC Calculator, which serves 425 ft² (average between 400 and 450 ft² for 10,000 BtuH unit per ENERGY STAR Room AC sizing chart). $F_{Room,AC} = (425 \text{ ft}^2 * 2.1)/(2323 \text{ ft}^2) = 0.38$

3.1.3 Roof and Cavity Insulation

Unique Measure Code(s): TBD

Draft date: 2/5/24

Effective date: TBD

End date: TBD

Measure Description

This involves increasing the insulation levels in either the attic or walls which directly define the boundary between the house or unit and the outdoors.

Definition of Baseline Condition

The baseline is amount of insulation in the house in its pre-treatment condition.

Definition of Efficient Condition

Any increase in insulation will reduce energy consumption compared to the pre-treated house.

Gas Savings Algorithms

$$\text{Annual Gas Savings (MMBtu)} = \frac{\text{HDD}_t \times 24 \times \text{AREA} \times \left(\frac{1}{R_{pre}} - \frac{1}{R_{post}} \right)}{(\text{AFUE} \times 1,000,000)}$$

Where:

HDD _t	=	Heating degree days at temperature t, where t=63°F if no programmable thermostat has been installed and t=62°F if a programmable thermostat has been installed. See the Reference Tables section at the end of this document for projected HDD.
24	=	Hours per day
AREA	=	Net insulated area in square feet. Estimated at 85% of gross area for cavities.
R _{pre}	=	R value of roof/cavity pre-treatment. R _{pre} = 5 unless there is existing insulation.
R _{post}	=	R value of roof/ cavity after insulation is installed.
AFUE	=	Rated AFUE of heating system. If no rating is available then use the method described in the Efficient Space Heating System section for calculating the AFUE. The AFUE of replacement equipment should be used if the heating system replacement precedes the air sealing work.

Electric Savings Algorithms

If the type of air conditioning is known, then use the appropriate algorithm below. If the type or existence of air-conditioning is not known, then assume that 45% have air-conditioning and estimate the cooling savings as 45% of a house with central air conditioning.¹¹

¹¹ Percentage of houses with air-conditioning from UGI data.

Reduced furnace fan or boiler circulator pump usage is also likely to occur and provide electricity savings during both the heating and cooling seasons.

Energy Savings

$$\Delta kWh = \Delta kWh_{Aux} + \Delta kWh_{Cool}$$

$$\Delta kWh_{Aux} = \text{Annual Gas Savings (MMBtu)} \times \text{Auxiliary}$$

$$\begin{aligned} \Delta kWh_{Cool} &= 0 \text{ kWh if house has no air conditioning} \\ &= \Delta kWh_{CAC} \text{ if house has central air conditioning} \\ &= \Delta kWh_{RAC} \text{ if house has room air conditioning} \\ &= 45\% \times \Delta kWh_{CAC} \text{ if no information about air conditioner} \end{aligned}$$

$$\Delta kWh_{CAC} = \frac{CDD \times 24 \frac{\text{hr}}{\text{day}} \times DUA}{SEER_{CAC} \times 1000 \frac{\text{W}}{\text{kW}}} \times \left[AREA \times \left(\frac{1}{R_{pre}} - \frac{1}{R_{post}} \right) \right]$$

$$\Delta kWh_{RAC} = \frac{CDD \times 24 \frac{\text{hr}}{\text{day}} \times DUA \times F_{\text{Room AC}}}{EER_{RAC} \times 1000 \frac{\text{W}}{\text{kW}}} \times \left[AREA \times \left(\frac{1}{R_{pre}} - \frac{1}{R_{post}} \right) \right]$$

Demand Savings

$$\begin{aligned} \Delta kW &= 0 \text{ kW if house has no air conditioning} \\ &= \Delta kW_{CAC} \text{ if house has central air conditioning} \\ &= \Delta kW_{RAC} \text{ if house has room air conditioning} \\ &= 45\% \times \Delta kW_{CAC} \text{ if no information about air conditioner} \end{aligned}$$

$$\Delta kW_{CAC} = \frac{\Delta kWh_{CAC}}{EFLH_{cool}} \times CF_{CAC}$$

$$\Delta kW_{RAC} = \frac{\Delta kWh_{RAC}}{EFLH_{cool RAC}} \times CF_{RAC}$$

Where:

ΔkWh = gross customer annual kWh savings for the measure.

ΔkW = gross customer summer load kW savings for the measure.

Auxiliary = Heating system auxiliary usage per MMBTU consumption (5.02 From Vermont Technical Reference Manual)

CDD = Cooling Degree Days (Degrees F * Days) See the Reference Tables section at the end of this document for projected CDD.

DUA = Discretionary Use Adjustment to account for the fact that people do not always operate their air conditioning system when the outside temperature is greater than 65F.

SEER_{CAC} = Seasonal Energy Efficiency Ratio of existing home central air conditioner (Btu/W·hr) (See table below for default values if actual values are not available)

$\overline{EER}_{RAC}$	= Average Energy Efficiency Ratio of existing room air conditioner (Btu/W•hr) (See table below for default values if actual values are not available)
CF_{CAC}	= Demand Coincidence Factor for central AC systems (See table below)
CF_{RAC}	= Demand Coincidence Factor for Room AC systems (See table below)
$EFLH_{cool}$	= Equivalent Full Load Cooling hours for Central AC and ASHP (Refer to EFLH table by climate zone in References Section)
$EFLH_{cool RAC}$	= Equivalent Full Load Cooling hours for Room AC (Refer to EFLH table by climate zone in References Section)
$F_{Room AC}$	= Adjustment factor to relate insulated area to area served by Room AC units

The default values for each term are shown in the table below.

Default values for algorithm terms, Ceiling/Attic and Wall Insulation

Term	Type	Value	Source
DUA	Fixed	0.75	OH TRM ¹²
$SEER_{CAC}$	Variable	Default values: Early Replacement = 10 Replace on Burnout = 13	PUC Technical Reference Manual
		Nameplate	Contractor Data Gathering
$\overline{EER}_{RAC}$	Variable	Default = 9.8	DOE Federal Test Procedure 10 CFR 430, Appendix F (Used in ES Calculator for baseline)
		Nameplate	Contractor Data Gathering
CF_{CAC}	Fixed	0.70	PUC Technical Reference Manual
CF_{RAC}	Fixed	0.58	PUC Technical Reference Manual
$F_{Room,AC}$	Fixed	0.38	Calculated ¹³

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Measure	Free Ridership	Spillover

¹² “State of Ohio Energy Efficiency Technical Reference Manual,” prepared for the Public Utilities Commission of Ohio by Vermont Energy Investment Corporation. August 6, 2010.

¹³ From PECO baseline study, average home size = 2323 ft², average number of room AC units per home = 2.1. Average Room AC capacity = 10,000 BtuH per ENERGY STAR Room AC Calculator, which serves 425 ft² (average between 400 and 450 ft² for 10,000 BtuH unit per ENERGY STAR Room AC sizing chart). $F_{Room,AC} = (425 \text{ ft}^2 * 2.1)/(2323 \text{ ft}^2) = 0.38$

Insulation	0%	0%

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

Measure	Measure Lifetime
Roof Insulation	40
Cavity Insulation	40

Source: NYSERDA Home Performance with Energy Star.

Water Savings

There are no water savings for this measure.

3.2 Domestic Hot Water End Use

3.2.1 Low Flow Showerhead

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This measure relates to the installation of a low flow showerhead in a home. This is an early replacement direct install or kit measure.

Definition of Baseline Condition

The baseline is the flow rate of the showerhead being replaced. If this is not available a baseline value of 2.5 GPM will be used.

Definition of Efficient Condition

The flow rate of the efficient showerhead should be greater than the flow rate of the baseline condition. If this value is not available it is assumed to be 1.5 GPM¹⁴.

Water Savings Algorithms

The water savings for low flow showerheads are due to the reduced amount of water being used per shower.

$$\Delta Gallons = \frac{(GPM_{base} - GPM_{eff}) \times N_{persons} \times T_{person-day} \times N_{showers-day} \times 365 \times ISR}{N_{showerheads-home}}$$

Where:

$$\Delta Gallons = \text{Gallons of water saved}$$

¹⁴ Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)

GPM_{base}	=	Maximum gallons per minute of baseline showerhead. Default = 2.5 GPM if measured rate is not available ¹⁵
GPM_{eff}	=	Maximum gallons per minute of the efficient showerhead
$N_{persons}$	=	Average number of people per household. Actual or defaults: SF=2.5, MF=1.7, Unknown=2.5 ¹⁶
$T_{person-day}$	=	Average minutes per person per day used for showering. 7.8 min/day ¹⁷
$N_{showers-day}$	=	Average number of showers per person per day. 0.6 showers/person/day ¹⁸
365	=	Days per year
ISR	=	In service rate. Kit Default = 35%. Direct install Default = 100%. ¹⁹
$N_{showerheads-home}$	=	Average number of showers per home. Actual or defaults: SF=1.6, MF=1.1, Unknown=1.5 ²⁰

Natural Gas Savings Algorithms

Gas energy savings result from reducing the amount of incoming cold water required to be heated due to the efficient showerhead.

$$\Delta MMBtu = \frac{[\Delta Gallons \times 8.3 \times c_p \times (T_{out} - T_{in})] / 1,000,000}{RE_{DHW}}$$

Where:

$\Delta MMBtu$	=	MMBtu of saved natural gas
8.3	=	Constant to convert gallons to pounds (lbs.)
c_p	=	Average specific heat of water at temperature range (1.00 Btu/lb·°F)
T_{out}	=	Assumed temperature of water coming out of showerhead (degrees Fahrenheit) 101 °F
T_{in}	=	Assumed temperature of water entering house (degrees Fahrenheit) 52 °F
RE_{DHW}	=	Recovery efficiency of the domestic hot water heater = 75% ²¹

Electric Savings Algorithms

It is assumed that all low flow showerheads are installed in homes that heat water using natural gas. There are no additional electric savings claimed.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

¹⁵ The Energy Policy Act of 1992 established the maximum flow rate for showerheads at 2.5 gallons per minute (GPM)

¹⁶ Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)

¹⁷ Ibid.

¹⁸ Ibid.

¹⁹ Ibid.

²⁰ Ibid.

²¹ Review of AHRI Directory suggests range of recovery efficiency ratings for new Gas DHW units of 70-87%. The average of existing units is estimated at 75% by the Northeast Energy Efficiency Partnerships' Mid-Atlantic Technical Reference Manual Version 1.1 (October 2010).

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

The measure life of a low flow showerhead is assumed to be 9 years²².

3.2.2 Low Flow Faucet Aerators

Unique Measure Code(s): TBD

Draft date: 3/6/22

Effective date: TBD

End date: TBD

Measure Description

This measure relates to the installation of a low flow faucet aerator in either a kitchen or bathroom.

Definition of Baseline Condition

The baseline is the flow rate of the existing faucet. If this is not available, it is generally assumed that a faucet will already have a standard faucet aerator using 2.2 GPM.

Definition of Efficient Condition

The efficient condition is a faucet aerator that has a flow rate lower than the baseline condition. If this value is not available than the flow rate is assumed to be 1.5 GPM²³.

Water Savings Algorithms

The water savings for low flow faucet aerators are due to the reduced amount of water being used per minute that flows down the drain (instead of being collected in the sink).

$$\Delta Gallons = \frac{(GPM_{base} - GPM_{eff}) \times N_{persons} \times T_{person-day} \times DF \times 365 \times ISR}{N_{faucets-home}}$$

Where:

$\Delta Gallons$	=	Gallons of water saved
GPM_{base}	=	Gallons per minute of baseline aerator = 2.2 GMP ²⁴
GPM_{eff}	=	Gallons per minute of the efficient aerator
$N_{persons}$	=	Average number of people per household. Actual or Defaults: SF=2.5, MF=1.7, Unknown=2.5 ²⁵
$T_{person-day}$	=	Average minutes per person per day of faucet hot water usage. Kitchen=4.5, Bathroom=1.6, Unknown=6.1 ²⁶
365	=	Days per year
DF	=	Drain rate, the percentage of water flowing down the drain. Kitchen=75%, Bathroom=90%, Unknown=79.5% ²⁷

²² Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (June 2011)

²³ Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)

²⁴ Ibid

²⁵ Ibid

²⁶ Ibid

²⁷ Ibid

ISR = In service rate. Kit delivery default = 28%, Direct install default = 100%²⁸

$N_{faucets-home}$ = Average Number of Faucets per home. Actual or for defaults see table below.

Average Number of Faucets per Home²⁹

Faucet Type	Single Family	Multifamily	Unknown
Kitchen	1.1	1.0	1.0
Bathroom	2.2	1.2	2.0
Unknown	3.3	2.2	3.0

Natural Gas Savings Algorithms

Gas energy savings result from avoiding having to heat the saved water due to the efficient aerator.

$$\Delta MMBtu = \frac{[\Delta Gallons \times 8.3 \times c_p \times (T_{out} - T_{in})] / 1,000,000}{RE_{DHW}}$$

Where:

$\Delta MMBtu$ = MMBtu of saved natural gas

8.3 = Constant to convert gallons to pounds (lbs.)

c_p = Average specific heat of water at temperature range (1.00 Btu/lb·°F)

T_{out} = Average mixed water temperature flowing from the faucet (degrees Fahrenheit) Kitchen=93 °F, Bathroom=86 °F, Unknown=87.8 °F³⁰

T_{in} = Assumed temperature of water entering house (degrees Fahrenheit) 52 °F³¹

RE_{DHW} = Recovery efficiency of the domestic hot water heater = 75%³²

Electric Savings Algorithms

It is assumed that all faucet aerators as part of the gas utility's program are installed in homes that heat water using natural gas. There are no additional electric savings claimed.

Freeridership/Spillover

Until studies have been performed to determine the free ridership and spillover, the values are assumed to be zero.

Persistence

The persistence factor is assumed to be one.

Measure Lifetimes

The measure life of a faucet aerator is assumed to be 10 years³³.

²⁸ Ibid

²⁹ Ibid

³⁰ Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)

³¹ Ibid

³² See assumption for low flow shower head.

³³ Pennsylvania Public Utility Commission Act 129 Technical Reference Manual (August 2019)

4 Reference Tables

4.1 Residential

4.1.1 Heating and Cooling EFLH

Heating and Cooling Equivalent Full Load Heating Hours

Reference Location	Zone	Heating EFLH for non-HP (Fossil Fuel Furnace or Boiler)
Allentown	C	906
Binghamton, NY	A	1,152
Bradford	G	1,347
Erie	I	1,054
Harrisburg	E	997
Philadelphia	D	761
Pittsburgh	H	942
Scranton	B	1,000
Williamsport	F	935
Weighted Avg CPA		1013

Source: Act 129 August 2019 TRM, Appendix A

Notes: ZIP codes associated with each PA climate zone may be found in the Act 129 August 2019 TRM, Appendix A, tab “Zip code lookup table.”

4.1.2 HDD & CDD

Heating Degree Days and Cooling Degree Days

Territory	HDD63	HDD62	CDD
Allentown	6,683	6,413	773
Binghamton, NY	5,350	5,110	405
Bradford	4,703	4,481	204
Erie	3,951	3,747	579
Harrisburg	4,512	4,294	1,121
Philadelphia	5,217	4,980	1,184
Pittsburgh	6,686	6,418	726
Scranton	5,054	4,830	608
Williamsport	5,477	5,241	759

Weighted Avg CPA	5,229	4,998	705

Sources: DegreeDays.net 2017-2019 for HDD, Act 129 August 2019 TRM, Appendix A for CDD.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
BRIAN SCUTTA ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

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I. Introduction

Q. Please state your name and business address.

A. Brian Scutta, 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

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

A. I am employed by Columbia Gas of Pennsylvania, Inc., (“Columbia” or “the Company”) as the Interim Vice President of Gas Operations.

Q. What are your responsibilities as Interim Vice President of Gas Operations?

A. My responsibilities include overseeing:

- Delivery of safe and reliable natural gas distribution service to our customers;
- Leak detection, leak investigation, leak response and leak repair activities;
- Customer metering activities;
- Plant operations;
- All required leakage surveys and system inspections, testing and inspection of cathodic protection systems for steel facilities, and performing underground facilities locating for third-party excavators;
- The day-to-day operations of Columbia’s physical natural gas piping system; and

- Field customer service to Columbia customers including odor complaints, meter turn-ons and turn offs, and all other customer interfacing field interactions.

Q. Please briefly describe your educational and professional experience.

A. I have been with Columbia and its parent company for 38 years, starting in the service department before transitioning into roles supporting construction projects, including replacement projects, new mains, and new business. Since 1997, I have held various leadership positions in gas operations and system operations, including Supervisor, Support Specialist, Operations Manager, Director of Gas Operations, and now Interim Vice President of Gas Operations.

Q. Have you testified before this or any other Commission?

A. No, I have not.

Q. What is the purpose of your direct testimony?

A. I will testify regarding Columbia's Distribution Integrity Management Program ("DIMP") and provide an overview of Columbia's distribution system. I will also discuss Columbia's historic operating performance, the initiatives taken to improve its overall safety and compliance efforts and the metrics that are used to track performance and progress, and the planned system enhancements to Columbia's operations, such as the rollout of Work and Asset Management ("WAM") program for the scheduling, dispatch, and execution of work and the management of underlying assets.

II. Overview of Columbia's Pipeline Distribution System

Q. Please describe Columbia's distribution system.

A. Currently, Columbia serves approximately 446,000 residential, industrial and commercial customers. The Company owns and operates a natural gas distribution system in 26 counties serving 450 communities spread across Pennsylvania. As of January 1, 2025, Columbia provides this service through approximately 7,803 miles of distribution and transmission mains and approximately 445,550 services that it owns, operates, and maintains.¹ These facilities (again, as of January 1, 2025) are composed of approximately 734 miles of bare steel, 22 miles of cathodically protected bare steel, 29 miles of wrought iron mains (in total, 785 miles of "first generation steel and wrought iron priority pipe" main), and 30,746 bare steel services.² The balance of the system is comprised of cathodically protected coated steel (some of which is pre-1971 coated steel, priority pipe), or plastic (some of which is pre-1982 plastic, priority pipe) mains and services, and 21 miles classified as other.³ As of December

¹ I note that in compliance with Section 1510 of the Pennsylvania Public Utility Code, in Western Pennsylvania the Company does not own the service lines all the way to the building, but terminates its ownership at the curb valve, typically found at or near the property line. If there is no curb valve on the service line, Columbia's ownership terminates at the property line itself. The customer then installs and maintains the remainder of the service line to the building.

² The terms "bare steel," "unprotected coated steel," "unprotected steel," and "wrought iron" as explained further below, are used interchangeably and all refer to steel pipe without cathodic protection that is susceptible to corrosion.

³ It should be noted that in 2011 Columbia deployed a Geographical Information System ("GIS") Mapping System to provide both mapping and data retrieval capabilities on its system and facilities. The 22 miles of "other" main appear to be anomalies in the data conversion and through a scrubbing process have been reduced from over 43 miles in 2012.

1 2022, Columbia had eliminated all known cast iron piping within its distribution
2 system.

3 Columbia's distribution infrastructure constitutes the final step in the delivery
4 of natural gas to customers from the producing regions of the Southern United States,
5 Western Canada, and in-state Pennsylvania-produced Marcellus and shallow well
6 supplies. Columbia distributes natural gas by taking it from delivery points (or "city
7 gates") along interstate pipelines, then transporting it through relatively small-
8 diameter distribution mains and services that network underground through cities,
9 towns, and neighborhoods to meet the demands of end-use customers. After taking
10 delivery of natural gas at the city gate, Columbia then steps down the transmission
11 pressure to local distribution pressure, further filters the gas to remove moisture and
12 particulates that may damage Columbia's system, and in some cases increases the
13 amount of odorant known as mercaptan (the "rotten egg smell") to the natural gas
14 before it is put into the distribution system. The gas then goes into the distribution
15 system where the pressure is often further reduced to delivery. Once the gas is
16 delivered to the outlet of the meter setting, or the property line in Western
17 Pennsylvania, it becomes the responsibility of the customer. In sum, Columbia's
18 distribution system moves relatively small volumes of natural gas at lower pressures
19 over shorter distances to a far greater number of individual users than its interstate
20 pipeline counterparts.

1 **Q. Please describe the years, types, and operating characteristics of the**
2 **various pipe materials that have historically been installed in Columbia's**
3 **system.**

4 A. The system is comprised of many different types of pipe. From the 1850s to the early
5 1900s, Columbia's predecessor companies installed cast iron pipe throughout the
6 early distribution systems. Cast iron, wrought iron and wood were among the first
7 materials available, and cast iron had the advantage in that it was relatively strong
8 and was easy to install. However, it was vulnerable to breakage from ground
9 movement. When the pipe was buried to typical depths of between two and five feet,
10 and the soil beneath the pipe or to its side was disturbed and pressure exerted on the
11 pipe, it could crack. Further, each pipe section was not easily joined, so joints were
12 prone to leaks. Finally, it was determined that cast iron was unsuitable for long-
13 distance transportation of gas because it was unable to withstand high pressures.

14 **Q. How did the industry react to the problems present with the use of cast**
15 **iron?**

16 A. By the early 1900s, the industry had adopted the use of steel and wrought iron piping
17 for mains. These were deemed to be stronger than cast iron and able to withstand
18 greater pressure. During this time, bare steel and wrought iron began replacing cast
19 iron pipe as the material of choice when building a natural gas distribution system.
20 During the pre- and post-World War II construction boom, gas utilities like
21 Columbia, along with developers and customers, installed a significant amount of

1 bare steel mains and services. Bare steel is steel pipe that has no exterior coating and
2 has no cathodic protection installed on the pipe. The use of bare steel and wrought
3 iron was common until the 1950s and 1960s when the industry began to realize that,
4 despite its initial strength, bare steel was subject to corrosion. In order to increase
5 long-term safety and reliability, coating and cathodic protection should be applied to
6 all new piping systems to slow the inevitable deterioration process. Both exterior
7 coatings and cathodic protection were designed to inhibit corrosion. Columbia
8 installed its last bare steel pipe in the 1960s. By 1970, the federal government
9 prohibited the installation of bare steel and wrought iron for natural gas distribution
10 system infrastructure.

11 **Q. What did the industry do to combat the problem of bare steel corrosion?**

12 A. The fact is that all metals corrode as a result of the natural process of chemical
13 interactions with their physical environment, most commonly caused by moist soil
14 (which creates an electrolyte) around the pipe. In these circumstances, direct electric
15 current flows from the metal surface into the electrolyte and, as the metal ions leave
16 the surface of the pipe, corrosion takes place. This current flows in the electrolyte to
17 the site where oxygen or water is being reduced. This site is referred to as the cathode
18 or cathodic site. To combat corrosion, natural gas distribution companies (“NGDCs”)
19 began using coated steel. Unprotected coated steel (“UPCS” or “coated steel”) refers
20 to steel pipe with an exterior coating (intended to electrically isolate the steel from
21 the surrounding electrolytes in the soil).

1 **Q. Did the use of UPCS solve the problem?**

2 A. No, despite the best efforts of industry, and even though it was, for a time, an accepted
3 industry standard, UPCS corroded as well. But for the period from the 1940s through
4 the 1960s, as the industry assessed its options, it was one of just a few alternative
5 piping materials available to meet the public demand for service. By 1970, Columbia
6 had laid its last UPCS segment. Coated steel pipe continues to be used, but it is
7 cathodically protected with an electric current.

8 **Q. What is the outlook for UPCS pipe?**

9 A. Since Columbia installed the last miles of UPCS in 1970, that pipe is reaching the end
10 of its useful life just by the passage of time and the inevitable resulting corrosion. In
11 addition, however, even though that pipe was coated to protect against corrosion,
12 some of that pipe is now being found to have been ineffectively coated. Ineffectively
13 coated steel pipe refers to coated steel pipe that may have inadequate, field-applied
14 coatings. Columbia continues to perform all routine monitoring and inspecting
15 activities to ensure that this type of coated steel pipe will continue to operate safely,
16 however, Columbia has a long-term concern that field-applied coatings used
17 primarily on steel pipe prior to 1955 - and intermittently between 1955 to 1970 - have
18 or will become ineffective over time. As this occurs, these coated steel lines
19 demonstrate the leakage characteristics of our bare steel pipe. In the interest of safety
20 and reliability, Columbia has been replacing many sections of coated steel main
21 installed prior to 1971 as it is encountered in association with a bare steel replacement

1 project. Columbia first inspects the pipeline coating for damage (e.g., scrapes,
2 gouges), deterioration, or disbonding (e.g., cracking, blistering, chipping, flaking, or
3 loose) and completes a field analysis to assess the cathodic protection current
4 requirements of the pipe. To the extent that these analyses identify segments of
5 protected steel pipe that are ineffectively coated, Columbia replaces that pipe as part
6 of its replacement program.

7 **Q. What materials replaced bare steel and coated steel?**

8 A. Coated steel pipe continues to be used, but it is cathodically protected with an electric
9 current. The pipe breakthrough for the natural gas industry came in the mid-1960s
10 with the introduction of plastic (polyethylene) pipe for gas distribution applications.

11 **Q. What is “cathodic protection?”**

12 A. Cathodic protection is a procedure by which underground metal pipe is protected
13 against corrosion and deterioration (i.e., rusting and pitting) by applying an electrical
14 current to the pipe. Cathodic protection reduces corrosion by making that surface
15 the cathode and another metal the anode of an electrochemical cell. A primary
16 function of a coating on a cathodically protected pipe is to reduce the surface area of
17 exposed metal on the pipeline, thereby reducing the current necessary to cathodically
18 protect the metal. At present, the principal methods for mitigating corrosion on
19 underground steel pipelines are external coatings and cathodic protection.

20 **Q. Has Columbia further improved the functionality of its piping since the**
21 **introduction of cathodically protected steel?**

1 A. Yes, it has. Cathodically protected steel has all the advantages of steel in terms of
2 strength and, because of its impressed electrical current, is highly corrosion resistant.
3 However, it is more costly to purchase and install and requires more ongoing
4 maintenance than the next generation pipe – plastic.

5 **Q. What are the benefits of plastic pipe?**

6 A. Plastic pipe has proven to be very good for distribution-level pressures. It has
7 strength and flexibility, and, as a result, is generally not susceptible to the stress of
8 ground movement. Plastic is also less costly to purchase and easier to join and install
9 than steel pipe. In addition, plastic does not corrode and, therefore, does not require
10 cathodic protection.

11 **Q. Does plastic pipe have any drawbacks?**

12 A. The two significant drawbacks to plastic include:

- 13 • Relative vulnerability to excavation damage as compared to steel. As a
14 result, excavators who do not dig by hand (despite being required to do so
15 by One-Call laws) in the vicinity of plastic facilities are more likely to
16 damage them. Steel piping has greater tensile strength and thus is
17 somewhat more likely to be able to resist external impact.
- 18 • “First Generation” plastic pipe also known as “Pre-1982 Plastic”, typically
19 installed between mid to late 1960s and 1981 in most distribution systems
20 are more brittle than today’s material (due to the different composition of
21 the base plastic material) and has demonstrated itself to be prone to stress

1 propagation cracking under some circumstances. In a special investigation
2 report completed by the National Transportation Safety Board on April 23,
3 1998, it was concluded that between the 1960s through the early 1980s, the
4 procedure used in the United States by manufacturers to rate the strength
5 of this plastic pipe may have overrated the strength and resistance to
6 brittle-like cracking. The investigation performed further clarified that
7 such first-generation plastic pipe was susceptible to premature brittle-like
8 failures when subjected to stress intensification and as a result represented
9 a potential safety hazard. Given the safety concerns that arise when this
10 pipe is subjected to stress intensification, the most efficient course of action
11 has been for Columbia to replace Pre-1982 pipe when it is encountered in
12 association with a pipeline replacement project. This eliminates the need
13 to induce stress on the first-generation plastic pipe during the standard
14 squeeze-off operation performed to control or stop gas flow when preparing
15 to reuse and reconnect existing first-generation plastic pipe to newly
16 installed plastic pipe, and it eliminates the risk of the pipe cracking due to
17 earth movement or other forces. As this Pre-1982 pipe continues to age,
18 the risk of it developing Type 1 leaks continues to grow and will need to be
19 replaced even when it is not associated with a bare steel or cast-iron
20 replacement program. In certain limited cases, Columbia's first-generation

1 plastic pipe has generated Type-1 leaks due to longitudinal cracking along
2 the pipe.

3 **Q. What is Columbia doing to address these concerns?**

4 A. Regarding excavation damage, Columbia continues to focus on improving facility
5 damage rates. In 2007, damages per thousand locates were at 5.39. By 2024, the
6 damages per thousand locate tickets was 2.09. Locate ticket volumes were up 10%
7 when compared to 2021, which indicates that excavators are increasing their One-
8 Call efforts. Nevertheless, total number of damages increased from 239 in 2021 to
9 327 in 2024. Excavator negligence remains the highest cause of damages to our
10 facilities, at 52% of total damages in 2024.

11 In response to excavator damages, Columbia adopted a “Damage Prevention
12 Risk Model” to guide its outreach to the riskiest excavators. Columbia is continuing
13 the practice of using “marker balls” when installing its new plastic facilities. These
14 marker balls are placed in the ground above the pipe after it has been installed and
15 enable Columbia to locate it later using electronic technology.

16 Columbia continues to deploy global positioning system (“GPS”) mapping and
17 locating technology that provide sub-decimeter accuracy in identifying the location
18 of new or replacement facilities. This technology will enable the Company to
19 accurately locate its new facilities in the field.

20 In order to address the issues discussed above with Pre-1971 coated steel pipe
21 and Pre-1982 plastic pipe, Columbia has replaced sections that are uncovered in the

1 course of executing the Company's infrastructure replacement program. Through
2 continued efforts to identify and reduce risk, Columbia evaluates risks from all pipe
3 materials, including first generation plastic pipe and Pre-71 coated steel, along with
4 bare steel, cast iron (all known cast iron was eliminated across the system in 2022)
5 and wrought iron. Those sections identified as higher risk within the system are
6 prioritized for replacement and are included as priority pipe in the Company's
7 current Long Term Infrastructure Improvement Plan.

8 **Q. How does Columbia classify leaks it detects on its system?**

9 A. Columbia classifies each gas leak according to its severity: Grade-1, Grade-2, or
10 Grade-3. A Grade-1 leak is hazardous and requires immediate remediation and
11 repair. A Grade-2 gas leak is non-hazardous at the time of detection, but requires a
12 scheduled repair based on the potential for becoming a hazard. A Grade-3 gas leak
13 is defined as "non-hazardous at the time of detection and can be reasonably expected
14 to remain non-hazardous."

15 These gas leak classifications are defined in the Gas Piping Technology
16 Committee ("GPTC") American National Standards Institute ("ANSI") Z380.1
17 "Guide for Gas Transmission and Distribution Piping Systems." The Guide is
18 commonly utilized by gas operators and State pipeline regulators, including the
19 Commonwealth of Pennsylvania, as an interpretation of "DOT 192 2003 CFR Title
20 49, Part 192 Transportation of Natural and Other Gas by Pipeline: Minimum Federal
21 Safety Standards."

1 **III. Federal Pipeline Safety Rules and Advisories**

2 **Q. Please describe the Federal Pipeline Safety Rules and Advisories that are**
3 **affecting and will continue to affect Columbia's Pipeline Safety Strategy**
4 **and Operational Execution.**

5 A. Some of the more significant and impactful Final Rules or Advisories issued in the
6 last several years or that are being considered for the future, are as follows:

- 7 • Integrity Management Program for Gas Distribution Pipelines (74 FR 63906)
8 - This final rule amended the Federal Pipeline Safety Regulations to require
9 operators of gas distribution pipelines to develop and implement integrity
10 management ("IM") programs. The IM programs required by this rule are
11 similar to those required for gas transmission pipelines but tailored to reflect
12 the differences in and among distribution facilities. Distribution integrity
13 management is playing a significant role in Columbia's gas operations,
14 allowing us to focus resources to reduce risks, thereby improving safety for
15 our customers, the public, and our employees.
- 16 • Pipeline Safety: Safety of Gas Transmission Pipelines: MAOP
17 Reconfirmation, Expansion of Assessment Requirements, and Other Related
18 Amendments (84 FR 52180; RIN 1) – Pursuant to National Transportation
19 Safety Board ("NTSB") recommendations and the Pipeline Safety, Regulatory
20 Certainty, and Job Creation Act of 2011, PHMSA has promulgated regulations
21 governing the safety of gas transmission pipelines. The purpose of this final

1 rule is to increase the level of safety associated with the transportation of gas.
2 This rule requires operators of certain onshore steel gas transmission pipeline
3 segments to reconfirm the maximum allowable operating pressure (“MAOP”)
4 of those segments and gather any necessary material property records they
5 might need to do so, where the records needed to substantiate the MAOP are
6 not traceable, verifiable, and complete. PHMSA is also requiring operators to
7 perform integrity assessments on transmission pipelines outside of high
8 consequence areas (“HCAs”) with an MAOP greater than or equal to 30% of
9 the specified minimum yield strength (SMYS) and are located in Class 3
10 locations, Class 4 locations, and in the newly defined moderate consequence
11 areas (“MCAs”). An operator must perform initial assessments in accordance
12 with this section based on a risk-based prioritization schedule and complete
13 initial assessment for all applicable pipeline segments no later than July 3,
14 2034. These assessments will provide important information to operators
15 about the conditions of their pipelines, including the existence of internal and
16 external corrosion and other anomalies, and will provide an elevated level of
17 safety for the populations in MCAs while continuing to allow operators to
18 prioritize the safety of HCAs.

- 19 • Pipeline Safety: Requirement of Valve Installation and Minimum Rupture
20 Detection Standards (87 FR 20940). PHMSA has promulgated regulations
21 to the Federal Pipeline Safety Regulations applicable to most newly

constructed and entirely replaced onshore gas transmission pipelines with diameters of 6 inches or greater. In the revised regulations, PHMSA requires operators of these lines to install rupture-mitigation valves (i.e., remote-control or automatic shut-off valves) or alternative equivalent technologies and establishes minimum performance standards for those valves' operation to prevent or mitigate the public safety and environmental consequences of pipeline ruptures. This final rule establishes requirements for rupture-mitigation valve spacing, maintenance and inspection, and risk analysis. The final rule also requires operators of gas pipelines to contact 9–1–1 emergency call centers immediately upon notification of a potential rupture and conduct post-rupture investigations and reviews.

- Pipeline Safety: Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments (87 FR 52224; RIN 2). PHMSA has promulgated regulations to the Federal Pipeline Safety Regulations to improve the safety of onshore gas transmission pipelines. The amendments in this final rule clarify certain integrity management provisions, codify a management of change process, update and bolster gas transmission pipeline corrosion control requirements, require operators to inspect pipelines following extreme weather events, strengthen integrity management assessment requirements, adjust the repair criteria for high-

1 consequence areas, create new repair criteria for non-high consequence
2 areas, and revise or create specific definitions related to the above
3 amendments.

4 **Q. Will PHMSA's focus on Transmission Lines have any significant impact**
5 **on Columbia operations?**

6 A. Yes, "Transmission Line" is defined in CFR 49, Part 192 as "a pipeline or connected
7 series of pipelines, other than a gathering line, that: (1) transports gas from a
8 gathering line or storage facility to a gas distribution center, storage facility, or large
9 volume customer that is not down-stream of a distribution center; (2) has an MAOP
10 of 20 percent or more of SMYS [System Minimum Yield Strength]; (3) transports gas
11 within a storage field; or (4) is voluntarily designated by the operator as a
12 transmission line.." Columbia has 40.7 miles of transmission class pipelines (7.13
13 miles within HCAs) per the 2022 PHMSA Annual Report for Natural Gas
14 Transmission and Gathering Systems for Columbia that meet this definition.
15 Further, following the San Bruno, California explosion which occurred on a Pacific
16 Gas and Electric Transmission Line in 2010, PHMSA has focused attention on the
17 quality and comprehensiveness of system records for these lines, particularly around
18 the pressure testing data, pipe material and design information, and wall thickness
19 of existing transmission line systems. Because there was no federal mandate
20 requesting such reports, Columbia, like many other NGDCs and transmission
21 companies, is lacking certain data, particularly on segments installed prior to current

code standards and the issuance of Federal Pipeline Safety Regulations instituted on August 1, 1971. PHMSA focused heavily on regulations for Transmission Operations between 2019 and 2022, as highlighted earlier in this testimony. Additional regulations coming out of the PIPES Act of 2020 are expected to impact transmission operations, in the coming years.

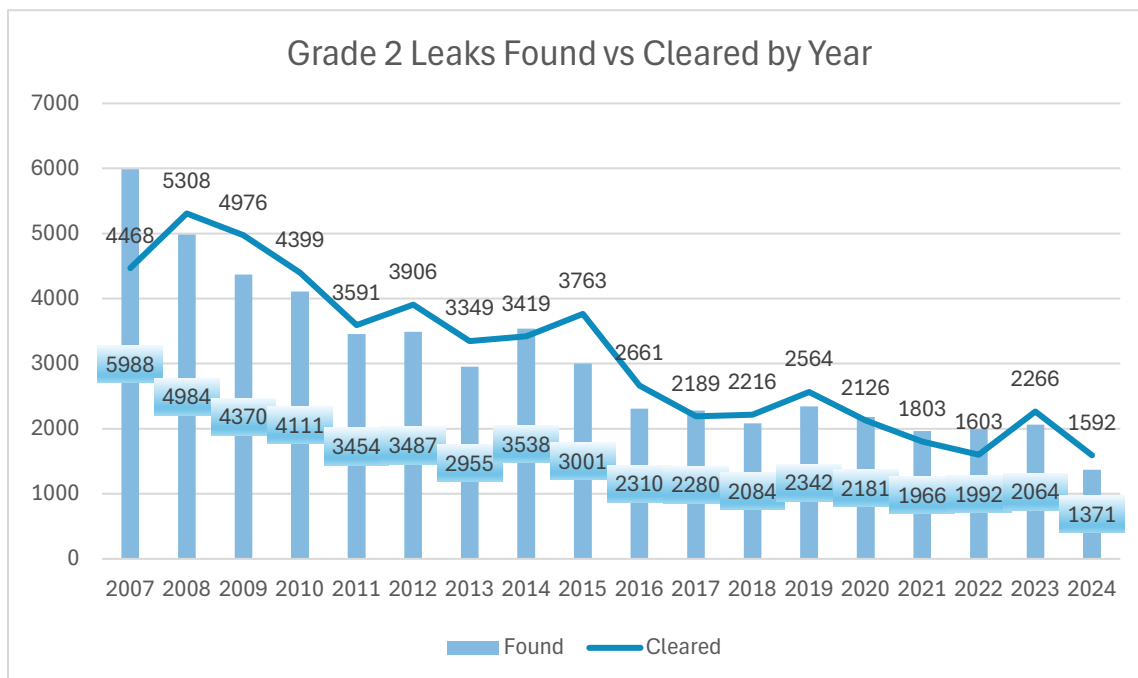
Q. Are there any additional details demonstrating the improvement of Columbia's system operations?

A. Some of the results from DIMP-driven practice enhancements or procedural changes, which improve Columbia's system, include:

Leakage Reduction: Since the inception of our accelerated infrastructure replacement program, Grade 2 leaks have been significantly reduced, thereby increasing the safety of our customers. Figure 1 below shows a comparison of Grade 2 leaks found during the year, as compared to Grade 2 leaks repaired during the year. In the last sixteen years alone, Columbia's pipeline replacement efforts were responsible for cutting the number of leaks found from 4,984 in 2008 to only 1,371 in 2024. That is more than a 72% reduction in leaks. That reduction in leaks improves safety, reduces methane emissions, and even improves service to customers since there are fewer service interruptions due to water-offs⁴ and leakage repairs. Going forward, the reduction of Grade 2 leaks will continue to be a focus.

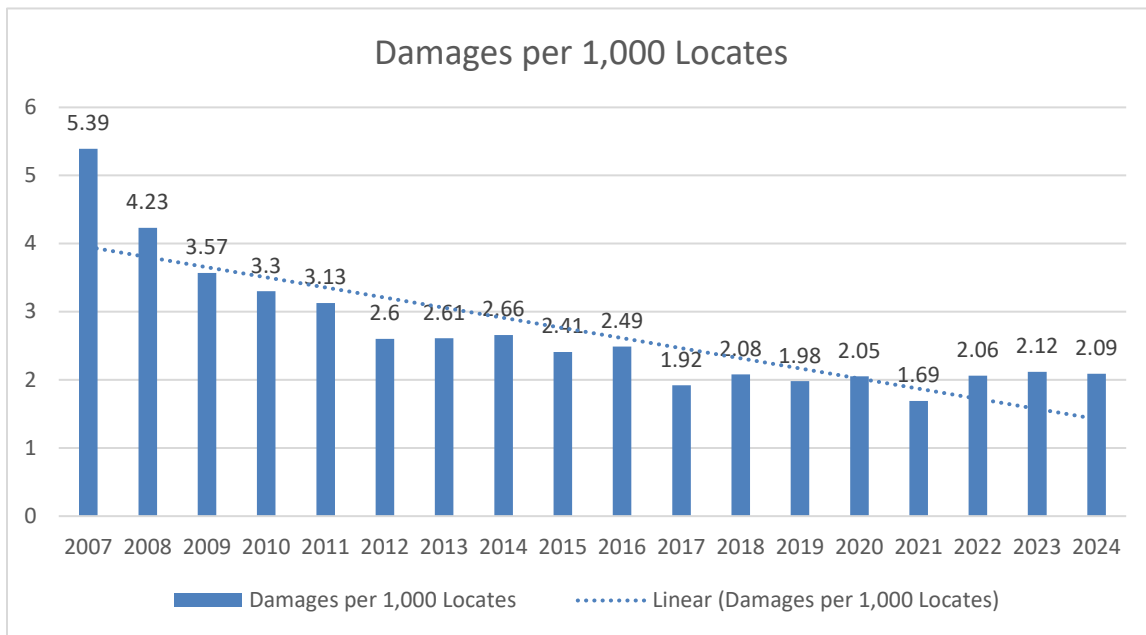
⁴ A water-off occurs when water enters the pipeline system (service line or main line) through a leak opening, or some other means. The water can accumulate in a specific area of that distribution system until it creates a blockage. This results in loss of pressure to one or more customers.

Figure 1
Columbia Gas of Pennsylvania, Inc.



Damage Prevention: The Company continues to focus on damage prevention. Since 2007, the Company reduced damages per 1,000 locates, as noted in Figure 2 below. In particular, the Company has focused on improving third party damages per 1,000 locates, as excavation damage is the leading cause of federally reportable pipeline incidents. These efforts have contributed to the 61% reduction in the damage rate on the Columbia system between 2007 and 2024, from a damage per thousand (locate requests) rate of 5.39 in 2007 to a damage per thousand rate of 2.09 through December 31, 2024, as shown in Figure 2 below.

Figure 2
Columbia Gas of Pennsylvania



Training Center: Columbia established a state-of-the-art training center, which opened in mid-2016, to support comprehensive employee training. This facility provides the necessary resources for classroom instruction, hands-on learning, and operator qualification testing/evaluation. It serves multiple purposes, including onboarding new employees, upskilling workers for advanced roles, conducting skill enhancement training, and preparing emergency responders.

Significant thought, research, and industry best practices were incorporated into the center's design. Trainers visited leading training facilities and natural gas distribution companies nationwide to study effective methodologies. Columbia also

1 organized focus groups to gather insights and feedback from frontline employees on
2 their training experience including the accessibility of gas standards while
3 completing real-world application of tasks.

4 The Technical Training Programs are supported with classroom instruction, in-field
5 support, and coaching, ensuring that employees acquire the necessary skills and
6 competencies to demonstrate their abilities to become operator qualified. The
7 curriculum integrates end-to-end training on Columbia's field technology and work
8 management systems, while also covering the essential program content. This
9 approach ensures employees gain a thorough understanding of their roles through
10 practical application at the training center, from hands-on fieldwork to accurate
11 documentation, which reinforces our commitment to safety, efficiency, and
12 compliance.

13 **IV. Columbia's Operating Performance**

14 **Q. In addition to Columbia's intense focus on pipeline safety, what are some**
15 **of the practice enhancements or procedural changes regarding**
16 **operating performance that are specific to customer delivery**
17 **performance?**

18 A. Over the course of the last nine years, Columbia initiated and/or continues to expand
19 on a number of customer service delivery improvements. These improvements
20 include 45-minute or less emergency response times and providing customers the

1 option of a two-hour appointment window, which have resulted in a safer and better
2 experience for our customers. For example:

- 3 • Columbia implemented 45-minute or less Emergency Response Rate targets.

4 Emergency response rates are integral to public safety. The sooner the first
5 Columbia responder arrives at a possible emergency, the quicker the situation
6 can be stabilized, made safe, and ultimately remediated. Since 2006,
7 Columbia has implemented a very structured approach to improving its
8 emergency response times, including the addition of field operations
9 positions, additional off-hours shifts, the use of GPS technology to enable
10 dispatching the closest/quickest responder to emergencies, and instructing all
11 employees to focus on responding to reported emergencies as safely and as
12 quickly as possible. In addition, Columbia continues to make enhancements
13 in an effort to keep emergency response rates down. Starting in 2011,
14 Columbia implemented an automated crew call out and resource
15 management system to call the service technician who can respond the
16 quickest to an issue that requires a response after hours. Columbia also
17 negotiated additional language to our labor contracts which requires a service
18 technician to be on Emergency Responder Rotation so that Columbia Gas has
19 an initial responder available 24 hours a day, 365 days a year. Additionally,
20 the Company negotiated residency requirements to better support emergency
21 response efforts. The results of these focused efforts have resulted in improved

performance in emergency response times. A comparison of the data showing the 45-minute or less response rates from 2015 to 2024 is shown in Figure 3, as follows:

Figure 3
Columbia Gas of Pennsylvania, Inc.

% of Priorities 45 mins or Less										
	2015	2016*	2017	2018	2019	2020	2021	2022	2023	2024
Day	96.79%	99.17%	99.16%	98.70%	98.99%	99.51%	99.50%	99.60%	99.50%	99.33%
Evening	90.95%	95.24%	94.87%	95.61%	97.28%	97.09%	96.10%	96.30%	97.10%	96.74%
Holiday	91.59%	92.11%	85.25%	86.32%	88.79%	95.35%	92.40%	91.20%	97.70%	91.60%
Overnight	85.87%	94.86%	95.19%	92.43%	90.42%	95.62%	95.60%	96.40%	97.50%	95.42%
Weekend	82.76%	91.83%	92.66%	91.72%	93.66%	95.31%	95.10%	93.20%	94.70%	93.93%
Total	92.68%	96.88%	96.82%	96.40%	97.28%	98.12%	97.80%	97.70%	98.20%	97.60%

- Columbia achieved an increase in the number of Columbia's on-time customer appointments, as measured by the overall annual percentage of on-time appointments met⁵. As more and more customers need to take time off from work to provide access to their homes for routine meter turn-on, turn-off, and other service-related activities, it is incumbent upon the Company to be as efficient as possible with the customers' time. Therefore, in 2007, Columbia began to focus specific attention on improving its percentage of on-time appointments. It did so by tasking the Integration Center (Columbia's Centralized Scheduling and Dispatch Center) with improving field employees' daily schedules to align more closely with the needs of customer

⁵ The percent of customer-generated appointments that are met within the appointment window or according to state regulation, where applicable.

1 appointments, and to shift non-emergency work, when possible, to meet
2 appointments that, for a variety of reasons, might otherwise be missed. As a
3 result of these efforts, Columbia has been able to improve its on-time
4 appointment rates from 97.83% in 2014, to a rate of 99.82% in 2024.

5 **Q. Please describe the Company's reduction in Occupational Safety and**
6 **Health Administration ("OSHA") recordable injuries.**

7 A. Columbia continues to enhance its culture of safety for customers, communities, and
8 employees. Employee safety has significantly improved as Columbia has experienced
9 a significant reduction in OSHA Recordable Injuries. For comparison, at the end of
10 2006, Columbia had 48 OSHA recordable injuries. This past year in 2024, there were
11 15 OSHA recordable injuries which is a reduction in frequency of 69%. Columbia has
12 previously received industry awards from both the American Gas Association and the
13 Energy Association of Pennsylvania in recognition of its safety performance. Our goal
14 is for every employee to go home safe and healthy every day.

15 Columbia's safety efforts include:

16 Each week, a safety communication is distributed to all Columbia leadership. The
17 safety message includes a summary of our safety performance including lagging and
18 leading indicators. Data driven and seasonal safety discussion materials are included
19 for each Leader to discuss with their team of workers.

1 Columbia delivers safety training to all employees. This employee safety training
2 encompasses role-specific training ranging from employee safe driver training, work
3 zone intrusion awareness to office ergonomics.

4 Columbia utilizes employee-led local and state-wide safety teams, which include
5 front line workers, leaders, contractors, and managers. These teams provide feedback
6 to the organization to drive continuous improvement and communicate
7 recommendations on, and implement, safety improvement opportunities
8 throughout the organization. Minutes from these meetings are shared with other
9 teams and posted virtually for access by others.

10 Columbia performs a robust post-incident review and root cause analysis involving
11 the team of the affected business unit of every worker injury and preventable vehicle
12 collision that involves a Columbia employee. Work zone intrusions and near miss
13 post incident review discussions are also conducted.

14 Columbia continues to implement the Energy Wheel, an energy-based hazard
15 recognition program where Columbia focuses on sources of energy that when
16 released can cause serious injury or fatality (SIF) events. This program facilitates the
17 prevention of fatalities and serious injuries that are life threatening or life changing
18 for the employee. The Columbia Energy Wheel safety program includes the high
19 energy concepts of, “STKY – Stuff that Kills You” and “HECA” High Energy Control
20 Assessments where Columbia identifies hazards and implements direct controls
21 focused specifically on the hazard so that if energy is released, no one is hurt or

1 injured. HECA is a method of measuring safety based on the proportion of high-
2 energy hazards with a corresponding direct control. HECA focuses on SIF prevention
3 and the measurement of safety as the presence of safeguards.

4 Supplementing our Energy-Based Hazard Recognition program, Columbia has also
5 created and implemented a Serious Injury or Fatality (SIF)/Severe PVC Incident
6 Program. A SIF event classification is based upon the amount and source of high
7 energy present and the severity of the event. Should a SIF events occur, they are
8 shared throughout Columbia Gas, for learning opportunities.

9 A core component of the Columbia safety program is the job site safety observation
10 initiative in which leaders and other support teams perform job site safety
11 observations in the field to coach employees on safe working behaviors, field work
12 activities, and to provide both positive and constructive feedback to employees in the
13 field. Each Leader in the organization is required to spend time in the field
14 conducting job site observations on our work sites and projects. This program also
15 includes our executives who are required to visit and to spend time with our
16 employees in the field. Our job site observation data is measured, monitored, and
17 communicated weekly and monthly as leading safety indicator across the
18 organization.

19 Columbia employees evaluate risk and identify the work hazards at each job site prior
20 to starting work and complete a pre-job safety briefing which is reviewed and
21 discussed with each employee on the job site or project. Our pre-job briefing process

1 also reinforces that all workers on our sites and projects have stop work authority. In
2 2024, Columbia added hazards related to the Energy Wheel.

3 Columbia has implemented the use of the Blackline Safety devices and vehicle
4 telematics. The purpose of vehicle telematics is to improve the safety of Columbia
5 employees, while providing a tool for improving driving behaviors and fleet
6 optimization. Telematics focuses on improving safety through providing the driver
7 the ability to correct their driving behaviors, coaching, and protecting drivers from
8 false claims with video exoneration.

9 The Blackline Safety device is an intrinsically safe wearable unit that provides the
10 employee with a handful of safety features aimed at enhancing their level of worker
11 safety when used in the field. It functions as personal gas detection monitor (H2S,
12 Oxygen, Carbon Monoxide, LEL), worker fall and 'no movement" detection, two-way
13 voice, and text messaging, push to talk communication with other Blackline units,
14 silent and audible SOS alerts, and employee location.

15 **Q. Regarding Columbia's operating performance, does the Company meet**
16 **or exceed state and federal requirements for leak surveying?**

17 A. Yes, in 2007, Columbia began an accelerated leakage survey program to inspect all
18 bare steel mains annually, instead of the three-year interval which is required in the
19 leakage survey requirements of CFR 49, Part 192. While annual surveys have been
20 performed for bare steel since 2007, Columbia has significantly reduced its inventory
21 of bare steel and seen a significant reduction in found leaks and plans to return to the

1 three-year leak survey interval for bare steel due to the decreased inventory and
2 reduced risks. Columbia intends to utilize the current resources to assist in the
3 implementation of Picarro leak detection to help drive risk down across our system.

4 **Q. Please provide a brief overview of the WAM component of NiSource's**
5 **planned 5-year IT Transformation?**

6 A. The term "WAM" refers to the development and system-wide deployment of new
7 integrated work and asset management IT systems to replace existing programs that
8 are at or near the end of their useful lives, not fully integrated, and at risk of failure.
9 NiSource's existing information technology systems that the WAM program will
10 replace are at the end of their useful lives, and, in some cases, are no longer
11 supported. In order to continue to provide reasonable and adequate service to
12 customers, NiSource must replace its aging infrastructure and invest in new software
13 systems. NiSource has focused on maintaining and repairing its core systems over
14 the last 20 years, as opposed to making significant investments in new
15 technology. As a result, the current systems that are at or nearing the end of their
16 useful lives are at risk of failure. In addition to requiring significant upgrades, the
17 current systems are costly to support and present risks in operating the business,
18 including cyber vulnerability risks.

19
20
21

Q. How will the WAM program benefit Columbia's operations?

A. The WAM program consists of three major components: (1) the "Work Management Initiative," which will substantially improve Columbia Gas' work and asset planning and management processes; (2) the "Mobile Workforce Initiative," which will support integrated planning of work in the field, scheduling, and work route planning; and (3) the "Mobile Mapping Initiative," which will provide mapping technology and functionality and allow front-line employees to view and capture more robust details about Columbia Gas' infrastructure when and where the work happens. The WAM program will reduce risk with maintaining our current aging IT systems. These enhancements are planning to go live on July 1, 2025.

Q. Do you have any additional comments regarding the WAM program?

How will these measures benefit Columbia's operations?

A. Yes. The WAM program will replace NiSource's outdated systems with systems that are the new industry standard and that can readily be integrated and supported over the estimated 15-year life of the assets. As a result of implementing the WAM program, NiSource anticipates improved operational efficiencies by reducing the amount of time spent in the field per work request, travel time and organization of travel time, and scheduling and dispatching time. Implementation of the WAM program will allow NiSource to begin using proven, fully integrated systems that are designed to be flexible and allow for growth for many years.

1 **Q. Do you have any comments regarding NiSource's efforts to drive**
2 **continuous improvement?**

3 A. Yes. As noted by Company witness Kempic in Statement No. 1, in 2023, NiSource
4 bolstered its continuous improvement and cost-saving efforts, by establishing a
5 dedicated team, consisting of field employees, that was tasked with looking at our
6 largest cost drivers as an organization and working with subject matter experts and
7 leadership to find opportunities to increase efficiencies, lean out processes, and
8 reduce cost.

9 Through these efforts, Columbia was able to ensure proper charging on leak repair
10 and leak survey work (Picarro); reduce inefficiencies related to locates by reducing
11 locate ticket volume through appropriate reduction of 811 buffers around our
12 facilities and using a risk driven approach to un-locatable facilities. In addition, the
13 Company implemented a job scouting process to reduce rework on jobs day to day
14 and pushed capacity of our workforce by focusing on productivity metrics daily.

15 **Q. Does this complete your Prepared Direct Testimony?**

16 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
GEORGE JONDA
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

1 **I. Introduction**

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

3 A. George Jonda, 290 West Nationwide Boulevard, Columbus, Ohio 43215.

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

5 A. I am employed by NiSource Corporate Services Company (“NCSC”) as NCSC
6 Regulatory Manager in the Financial Planning and Analysis (“FP&A”) department.
7 NCSC is a wholly owned subsidiary of NiSource Inc. (“NiSource”).

8 **Q. What are your responsibilities?**

9 A. As NCSC Regulatory Manager, my principal responsibilities include sponsoring,
10 supporting, and assisting in the NCSC budgeting and reporting process. This
11 includes NCSC allocations within the budget, monthly reporting and variance
12 analysis of NCSC costs, update of the current year forecast through the Present
13 Estimate process, maintaining NCSC headcount analysis, as well as other ad hoc
14 support for the corporate functions. This support centers around operations and
15 maintenance (“O&M”) expenses for the corporate functions and overhead costs
16 across all NiSource companies, including NCSC and Columbia Gas of Pennsylvania,
17 Inc. (“Columbia” or “the Company”).

18 **Q. What is your educational and professional background?**

19 A. I received a Bachelor of Science degree in Construction Management from The Ohio
20 State University in Columbus, Ohio in December 2008 and a Master of Business
21 Administration from Capital University in Columbus, Ohio in December 2014. I am

1 a Certified Managerial Accountant. My professional experience prior to NiSource
2 includes roles as a Project Cost Analyst with American Electric Power Inc. supporting
3 generation projects, a Project Manager supporting higher education construction
4 projects, and a Corporate Controller for an engineering services firm. In October
5 2020, I began working with NiSource as an external consultant supporting various
6 NCSC initiatives and took a full-time position as a Lead Financial Analyst in
7 December of 2021. In that role, I supported several functional areas of the business
8 to help them meet their financial targets through detailed budgeting and cost
9 tracking. In December 2024, I assumed my current position of NCSC Regulatory
10 Manager.

11 **Q. Have you ever testified before a regulatory Commission?**

12 A. I have not testified before a regulatory Commission.

13 **Statement of Purpose**

14 **Q. Please describe the purpose of your testimony in this proceeding.**

15 A. The purpose of my testimony is to provide background on the budgeting process for
16 corporate functions, overhead expenses, and how that relates to the budget for
17 Columbia. My testimony supports projected O&M expenses for NCSC charges to
18 Columbia for the Future Test Year (“FTY”) ending November 30, 2025, and the Fully
19 Projected Future Test Year (“FPFTY”) ending December 31, 2026, in Exhibit 104,
20 Schedule 1, pages 5 and 6, with ratemaking adjustments to the test years supported
21 by Columbia witness Joseph Vassalotti in Columbia Statement No. 4. Company

witness Jason Leal will be supporting the budgeting process for Columbia's Gas Utility Segment departments in Columbia Statement No. 18.

Q. Please describe the primary components of the NCSC budget.

A. The NCSC Budget is comprised of Corporate O&M and Overheads. Corporate O&M includes functions such as Information Technology, Finance, Accounting, Legal, Tax, Supply Chain, Treasury, Risk Management, Call Center Operations, Human Resources, Safety Services, and Utility Operation Support. Overhead expenses include short and long-term incentive compensation, retirement benefits (e.g., 401K, pension), insurance benefits (e.g., disability), and health benefits (e.g., vision, medical), and the use of shared assets.

Q. Can you describe the annual budget development process for Corporate O&M and Overheads?

A. The NiSource O&M expense budgeting methodology is a "top down" approach, as informed by lower levels of management, which facilitates decision points to ensure the highest and best use of available dollars. "Top down" is necessary to ensure that NiSource maintains its financial commitments (e.g. credit rating) to ensure capital availability necessary to maintain the infrastructure to deliver safe, reliable energy. Information at various levels and functions are necessary to capture the detailed department level requirements of the business to provide each functional leader (e.g., IT, Legal, Engineering) with an operating budget. Ultimately, the overall NiSource O&M targets are established by the Executive Vice President and Chief Financial

Officer and SVP of Financial Planning & Analysis and presented to the Executive Leadership Team for approval. Department budgets are refined and updated as necessary after targets are set.

Q. Please elaborate.

A. Using the O&M targets set by the Executive Leadership Team as a guidepost, it is the responsibility of the Financial Planning team, along with functional leaders, to work together to ensure functional O&M budgets are developed in accordance with overall financial goals and objectives.

Budgeted expenses are grounded in a trailing 12-month historical spend with merit increases and inflation adjusted for each year thereafter, delineated by cost categories such as labor, materials, and outside services. Overhead costs are calculated based on labor (e.g., incentive compensation) or provided by actuarial firms (e.g., pension and benefits).

Q. What are the principal assumptions used in the development of the labor cost element for specific department budgets?

A. Labor expense is determined based on projected headcount and wage increase assumptions for the FTY and FPFTY for total NCSC. The budgeting process for labor costs begins with the organizational chart that is current when the budget process is initiated. Anticipated changes such as new hires, promotions, transfers, and terminations are incorporated with input from department leaders to ensure accuracy. The labor planning module applies an annual merit increase. This

1 adjustment accounts for salary changes driven by performance, inflation, or market
2 conditions, and aligns with the company's overall compensation strategy or any
3 specific budget guidelines for the year. Additionally, the planning system applies a
4 capitalization rate grounded in a trailing 12 months of historical spend, which adjusts
5 net labor expense to reflect capitalized labor. The projected labor expense by
6 department is then compared to the prior year's values for reasonableness and
7 accuracy before finalizing the plan.

8 **Q. What are the principal assumptions used in the development of the non-**
9 **labor cost elements for specific department budgets?**

10 A. Non-labor, non-overhead expenses ("Direct Expenses") are rooted in historical
11 trends to reflect normal ongoing levels of expense and are then adjusted up or down
12 for known activities or events reasonably expected to occur or not recur.

13 **Q. Do Corporate O&M and Overheads include allocations from NCSC, and**
14 **if so, how are the cost allocations to Columbia determined?**

15 A. Yes, NCSC is a subset of the budget for Corporate O&M and Overheads. Allocations
16 from NCSC to the operating companies are based on historical distributions and
17 adjusted as necessary to best represent expenses planned for future periods. Witness
18 Vassalotti has provided detail around allocations in his Direct Testimony.

19 **Q. Is the budget development process consistent with Columbia's prior**
20 **rate cases?**

21 A. Yes, the process is consistent.

1 **Q. Is the budget reviewed throughout the year?**

2 A. Yes. Each month an analysis that compares budget to actual results is completed and
3 reviewed. This analysis provides key drivers for variances for both monthly and year-
4 to-date results. In addition to monthly variance analysis, updates are conducted with
5 function leaders that provide forecast updates for the current year and any impact to
6 future years (known as the “Present Estimate”). Documentation of the drivers of the
7 variance are maintained and evaluated in future planning cycles to ensure proper
8 consideration of new and developing forecast items.

9 **Q. Does this complete your Direct Testimony?**

10 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

DIRECT TESTIMONY OF
DEBORAH A. DAVIS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

Introduction

Q. Please state your name and business address.

A. My name is Deborah A. Davis, and my business address is 121 Champion Way, Suite 100, Canonsburg, Pennsylvania 15317.

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

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as Manager, Universal Services.

Q. What are your responsibilities as Manager, Universal Services?

A. I am responsible for efficient and compliant administration of all programs for low-income customers including the Customer Assistance Program ("CAP"), the Low-Income Usage Reduction Program ("LIURP"), the Customer Assistance, Referral and Evaluation Services program ("CARES") and Columbia's Hardship Fund, as well as other programs that assist low-income customers.

Q. What is your educational and professional background?

A. I hold a Bachelor of Arts degree in Social Work from the University of Pittsburgh. Prior to joining Columbia in 1992, I was employed at a community-based agency assisting low-income clients with accessing utility service and providing other basic life necessities. I was hired by Columbia as a Community Relations representative and subsequently became Manager of the Customer Programs Department. My titles have changed over the years, but I have remained in a similar function throughout my 30-plus year career at Columbia.

1 **Q. Have you testified before the Pennsylvania Public Utility Commission**
2 **(“Commission”) or any other commission?**

3 A. Yes. I have testified before the Commission on behalf of Columbia in its 2011, 2012,
4 2014, 2016, 2018, 2020, 2021, 2022, and 2024 base rate cases at Docket Nos. R-
5 2010-2215623, R-2012-2321748, R-2014-2406274, R-2016-2529660, R-2018-
6 2647577, R-2020-3018835, R-2021-3024296 R-2022-3031211, and R-2024-
7 3046519, respectively.

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

9 A. In my testimony, I describe three proposals relating to low-income customer
10 programs and provide support for implementation of the proposals. First,
11 Columbia proposes a two-year pilot to address an existing barrier to re-enrolling
12 customers in the Company’s CAP (“CAP Pilot”). In addition, in accordance with the
13 Settlement of Columbia’s last base rate case at Docket R-2024-3046519, Columbia
14 proposes a two-year pilot program to use speech analytics technology to improve
15 outreach to CAP customers (“Speech Analytics Pilot”). Finally, Columbia proposes
16 a change to the recovery of costs associated with CARES and CAP administration.
17 Columbia proposes to recover the costs associated with all three proposals through
18 the Universal Services Rider (“Rider USP”).

19 **II. CAP Pilot**

20 **Q. Please describe the proposed CAP Pilot.**

1 A. CAP arrears, to the extent a former CAP customer has any, is the amount
2 customers are required to pay to re-enter CAP. The Company recognizes that the
3 requirement to pay outstanding CAP arrears is a barrier to re-entry into the
4 program. Therefore, Columbia is proposing a two-year CAP Pilot, which will
5 provide a one-time grant to assist with payment of outstanding arrearage balances
6 for customers who are otherwise eligible to re-enter the Company's CAP. The
7 Company proposes to fund the two-year CAP Pilot at \$100,000 annually, to be
8 recovered through Rider USP. Columbia estimates that the CAP Pilot will provide
9 assistance to a minimum of 153 customers. Additionally, the Company will also
10 evaluate the CAP Pilot's impact to payment and reverification rates.

11 **Q. Please provide additional details of the CAP Pilot.**

12 A. The Company will issue a grant of up to \$650 for payment of CAP arrears,
13 facilitating re-entry into the CAP. The Company anticipates it will be able to serve
14 more than 153 customers, since not all grant recipients will require the entire \$650
15 grant for re-entry. Customers will be approved for the grant by the current CAP
16 administrator, Dollar Energy Fund ("DEF"), while the Company's Energy
17 Assistance Team ("EAT") will be responsible for posting the grants to customer
18 accounts. Once the grant is posted, the customer will be re-enrolled into CAP
19 without further delay.

20 **Q. What are the eligibility requirements for the CAP Pilot?**

A. The customer must meet all existing CAP requirements as specified by the Company's Universal Services and Energy Conservation Plan ("USECP"), and the customer must have outstanding CAP arrears equal to or less than \$650. Additionally, customers are eligible for only one grant through the CAP Pilot.

Q. Why is the Company proposing a maximum grant of \$650?

A. The Company's hardship fund requires that a customer provide a \$150 good faith payment to be eligible to receive a grant up to \$500. The CAP Pilot maximum grant of \$650 would be equivalent to receiving the maximum hardship fund grant without the requirement of the \$150 good faith payment. Further, the Company reviewed historic arrearages for CAP customers and found that most of these customers owe less than \$650 in arrears. Amounts of CAP arrears by customer counts as of December 31, 2024 is shown below:

CAP Arrears	# of Customers
>\$1,000	25
\$800 - \$1,000	20
\$650 - \$800	17
0 - \$650	3,960

Q. How will customers that owe more than \$650 in CAP arrears be able to re-enter the CAP?

A. The Company's existing policy requires a customer pay no more than \$300 out of pocket and apply for any available programs to reduce the CAP arrears. This would continue to be the case for customers with CAP arrears greater than \$650. If any

1 combination of customer payment and assistance programs brings the CAP arrears
2 to \$650 or less, the customer would be eligible for the pilot.

3 **Q. How did the Company determine the budget for this pilot?**

4 A. A review of Company records indicates there are just over 4,000 removed CAP
5 customers identifying as having income less than 150% of the Federal Poverty
6 Income Guidelines (“FPIG”) who owe both CAP and non-CAP arrears. At the time
7 of filing, there were 150 qualified customers with applications on file and
8 outstanding arrearages. The average CAP arrears for these customers is \$370.00
9 The Company anticipates that 270 applicants, based on average arrears and total
10 budget, will be within the internal team’s capacity to manage and will provide a
11 good sample size to evaluate the impact of the CAP Pilot.

12 **Q. How will the Company determine eligible customers?**

13 A. The CAP administrator, DEF, will follow normal processes to verify eligibility.
14 Once verified, customers with CAP arrears balances less than or equal to \$650 will
15 be referred to Columbia for a CAP Pilot grant on a first come, first served basis
16 until funds are exhausted.

17 **Q. How will the Company promote the CAP Pilot program?**

18 A. The Company does not anticipate a need to actively promote the program beyond
19 its normal outreach activities. While CAP Pilot funds are available, Company
20 Customer Service Representatives (“CSRs”) will identify and refer eligible
21 customers for assistance through this pilot in addition to other open programs,

1 such as LIHEAP, CRISIS and hardship funds. If CAP Pilot funds remain available
2 three months after initial implementation, the Company will include written
3 information to customers who identify as having income less than 150% FPIG,
4 previously participated in CAP, and have recently agreed to a payment
5 arrangement. This written communication would be in addition to the referral that
6 would have been made by the CSR upon the customer entering into a payment
7 agreement.

8 **Q. How will the Company define the success of the CAP Pilot?**

9 A. The Company will track the customers that received CAP Pilot grants and assess
10 these customers' payment rates and duration of participation in comparison to
11 customers re-entered without the CAP Pilot grant. Columbia would measure the
12 success of the CAP Pilot's goals by higher participation in CAP, improved payment
13 rates, increased reverification rates and continued participation in CAP. A
14 minimum of two years after the completion of the two-year CAP Pilot will be
15 required to fully analyze the impact to the reverification rates because most
16 customers do not need to verify their income on an annual basis.

17 **Q. How will the Company report the progress of the CAP Pilot?**

18 A. The Company will provide a report by month at each of its Universal Services
19 Advisory Council ("USAC") meetings to include the following:

- 20 • Number of participants accepted
- 21 • Number of denials and corresponding reasons

- Total dollars granted
- Average, Minimum and Maximum grant amount

The Company will also provide an annual report to its USAC 14 months and 24 months after implementation with the following information for the first and second year:

- Total Number of Participants accepted
- Total Number of on-time payments
- Total Number of Customers removed and corresponding reasons
- Current CAP Arrears Balances
- Any available reverification data (zero income would verify every 6 months, all other customers a minimum of two years)

III. Speech Analytics Pilot

Q. What is the goal of the Speech Analytics Pilot?

A. The Speech Analytics Pilot has two primary goals. The first goal is to verify that existing Company policies related to CAP referrals are being followed. The second goal is to improve the rate of referrals to the CAP program at the Customer Care Center by identifying key contacts, conversations and words/phrases that would more quickly recognize a CAP-eligible customer and then utilize those to adjust processes to make appropriate referrals to the CAP as soon as possible.

Q. Why is the Company proposing this Pilot?

1 A. Per the Settlement of Columbia's base rate case at Docket R-2024-3046519, the
2 Company proposes the Speech Analytics Pilot to improve identification of
3 customers potentially eligible for assistance programs at the Company's Customer
4 Care Center.

5 **Q. What is Speech Analytics Technology?**

6 A. Speech Analytics Technology ("SAT") is a tool that uses artificial intelligence and
7 natural language processing to analyze customer conversations from live or recorded
8 audio data. This technology helps identify and understand call drivers by pinpointing
9 keywords or themes in conversations.

10 **Q. Please describe how the Company intends to use SAT.**

11 A. The Company intends to use the technology in two phases.

12 In Phase 1, the Company will utilize SAT to screen recordings of calls related to
13 payment arrangements. The tool will look for specified words, phrases, or themes, as
14 recommended by the Company's USAC, to identify customers that may not have been
15 referred to CAP but may be eligible based on the conversation. This will help achieve
16 the first goal of verifying that existing policies related to CAP are being followed.

17 In Phase II, the Company will screen recordings of a sample size of all call types with
18 the intention to expand screening all calls. The Company will again look for specified
19 words, phrases, or themes, as recommended by the Company's USAC, to identify
20 customers that may not have been referred to CAP but may be eligible based on the
21 conversation. This will help the Company identify key contacts, conversations, and

1 relevant words, phrases, and themes that could assist in refining processes and
2 scripting to encourage a potential CAP customer to follow through as soon as
3 possible. Both Phases of the Speech Analytics Pilot will be implemented
4 simultaneously.

5 **Q. What does the Company intend to do with the SAT results?**

6 A. The Company will utilize the SAT results in several ways. Depending on the results,
7 the Company may need to retrain and stress existing policies; develop new scripting
8 to encourage CSRs to hear and respond to certain additional trigger words, phrases,
9 or themes; and/or develop additional training for CSRs to seek additional
10 information based on what the customer says during a call. The overall goal is to
11 increase appropriate referrals to the CAP from the Customer Care Center.

12 **Q. What is the proposed budget for the Speech Analytics Pilot?**

13 A. The Company intends to use the SAT, if approved, to increase appropriate CAP
14 referrals in 2026. The estimated annual budget for this Pilot is \$300,000, which will
15 include Columbia's prorated portion of the annual licensing fee, programming the
16 SAT, analyzing results and any potential follow up related to training. Columbia
17 proposes to recover this annual budget through Rider USP.

18 **Q. How many calls will the SAT review?**

19 A. The Company will utilize the SAT to review a minimum of 10,000 calls, with the goal
20 of expanding to review all calls.

21 **Q. How does the Company intend to engage its USAC in the Speech**

Analytics Pilot?

A. The Company has already engaged its USAC to gain feedback on the Speech Analytics Pilot. The USAC has encouraged the Company to provide it with data by zip code in order to identify any geographical opportunities and encouraged the Company to include calls from non-English speaking customers in the sample of calls reviewed by SAT. The Company will continue to engage with members of the USAC to provide feedback regarding the appropriate words and phrases the SAT will use in the Pilot. The Company will share the final plan with the USAC to receive feedback, and the Company will share preliminary findings and ongoing results with its USAC.

IV. Recovery of CARES and CAP Costs

Q. What is the Company proposing to change regarding CARES and CAP costs?

A. The Company proposes to recover costs associated with CARES and CAP through the Rider USP. Currently Universal Service costs associated with the Company's Energy Assistance Team ("EAT"), which handles the administration of LIHEAP/CRISIS and CAP accounting are recovered in base rates. The Company is proposing for the EAT expenses to be removed from base rates following transition of EAT cost recovery to the Rider USP. This will ensure no double recovery of the costs as base rates will be reduced by the expense estimate to be transferred to the Rider USP Regulatory Asset as discussed in the Direct Testimony of Columbia witness Vassalotti.

Q. Please explain the purpose and responsibilities of Columbia's EAT.

1 A. The EAT is responsible for the administration of all energy assistance activities, from
2 outreach and processing grants to trouble shooting issues. EAT administers all
3 energy assistance programs including LIHEAP, CRISIS, Homeowner Assistance
4 Fund, Emergency Rental Assistance Program, hardship funds, Customer Assistance
5 Program, Security Deposit Assistance Fund, and miscellaneous benevolent funds
6 from social service agencies. Responsibilities of team members include:

- 7 • Answering a toll-free hotline to review accounts and coordinate grant
8 approvals with local and state agencies;
- 9 • Responding to all email requests for information or CAP inquiries;
- 10 • Approval of hardship fuel fund grants to eligible applicants;
- 11 • Processing of all grants on customer accounts;
- 12 • Communicating with the Customer Care Center of changes to program
13 eligibility criteria and guidelines to ensure compliance with all
14 established vendor agreements and policies;
- 15 • Collaborating with the Company's Communications, Marketing, and E-
16 Channels departments to update or report changes to program eligibility
17 criteria and guidelines prior to the release of all customer
18 communications;
- 19 • Collaborating with Information Technology department to implement
20 all regulatory changes resulting from approved USECPs and rate cases;

- Completing all reporting obligations outlined in established vendor agreements;
- Waiving and processing refunds of security deposits for CAP applicants;
- Outbound letters, phone calls and emails to customers to promote and encourage participation in energy assistance programs; and
- Processing of all grant refunds.

Q. Why is the Company proposing to recover the costs of the EAT through Rider USP?

A. Costs associated with the administration of Universal Service Programs are recovered through Rider USP. Currently, all CAP external administration and all costs associated with the LIURP program are recovered through Rider USP. The EAT is critical to the outreach and delivery of LIHEAP and CAP, as well as all other grant programs, and therefore, internal labor costs should be recovered through Rider USP, and not base rates. This change will allow for a better accounting of the total costs to deliver Universal Service programs to Columbia's customers.

In addition, the workload associated with managing the new outreach avenues, including the data received from the Department of Human Services ("DHS") and streamlining of CAP applications, requires additional staffing. Recovering these costs through Rider USP will permit the Company to appropriately staff for fluctuating demands only when the additional staffing is necessary.

Q. Has the role of the EAT changed over the years?

1 A. Yes, the role of the EAT has evolved over the last 25 years due to additional LIHEAP
2 responsibilities and requirements, shifting of Company responsibilities, and
3 availability of additional assistance programs. Originally, the EAT consisted of one
4 full-time Company employee and three seasonal temporary staff. The full-time
5 employee was responsible for processing all LIHEAP payments and refunds, while
6 the three seasonal temporary staff answered incoming calls from customers
7 requesting information about energy assistance programs or a LIHEAP application.
8 The Company shifted the responsibilities of customer referrals to available programs
9 to the Customer Care Center and designated the EAT as the centralized team for local
10 and state agencies to contact for account review and coordinating grant approvals
11 while still retaining the responsibility of processing LIHEAP and Crisis payments,
12 refunds, and LIHEAP application mailings.

13 As the demands of LIHEAP increased due to end of year refunds, summer
14 supplemental payments, and reporting requirements, the Company hired two
15 additional full-time employees. Additionally, the responsibility of communicating
16 changes to program criteria to the Customer Care Center and collaborating with
17 other departments prior to the release of all customer communications related to
18 energy assistance was designated to EAT.

19 In 2020, the Company hired an additional full-time employee to meet the strain on
20 EAT when it absorbed the responsibilities of handling all CAP related inquiries,
21 approving hardship fuel fund grants, collaborating with the Information Technology

1 department to implement all required regulatory updates, conducting direct
2 outreach to customers, and developing and administering processes related to the
3 implementation of additional state assistance programs resulting from the COVID
4 pandemic, such as Homeowners Assistance Fund and Emergency Rental Assistance
5 Program.

6 **Q. How many full-time employees currently staff the EAT?**

7 A. The EAT consists of one supervisor, three full time employees and one full time
8 temporary employee.

9 **Q. What are the current approximate costs that would be shifted from O&M**
10 **to Rider USP?**

11 A. The current approximate costs that would be shifted are \$220,000 annually. These
12 costs may change due to required outreach opportunities and a full season of data
13 received from the DHS.

14 **Q. Will this proposed change create a risk to over-recover costs, both**
15 **through O&M and through Rider USP?**

16 A. No. The Company currently has established processes to recover internal labor and
17 expenses associated with the LIURP program through Rider USP. The Company has
18 undergone multiple audits, all of which found no evidence of over-recovery related
19 to internal administrative costs of LIURP. If approved, the Company would use the
20 existing processes to ensure costs are only recovered through the Rider USP.

21 **Q. Will this change require any tariff changes?**

1 A. Yes. The definition of the Rider USP is located on page 146 of the Company's tariff.
2 The Company is proposing to add a sentence to the first paragraph under the
3 calculation of the rate to state "and any other replacement or Commission- mandated
4 Universal Service Program or low-income program that is implemented during the
5 period that the rider is in effect." In its entirety, the paragraph would state, "The
6 Rider USP rate shall be calculated to recover costs for the following programs: Low
7 Income Usage Reduction Program (LIURP); Customer Assistance Program (CAP);
8 and the WarmWise® Audits and Rebates program; and the Emergency Repair
9 Program (ERP) and any other replacement or Commission- mandated Universal
10 Service Program or low-income program that is implemented during the period that
11 the rider is in effect." Company witness Danhires (Columbia Statement No. 12)
12 addresses the necessary changes to the tariff in her Direct Testimony.

13 **Q. Does this conclude your prepared Direct Testimony?**

14 A. Yes, it does.

**BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

DIRECT TESTIMONY OF
JOHN D. TAYLOR
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20, 2025

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I. Introduction

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

A. My name is John D. Taylor, and I am employed by Atrium Economics, LLC (“Atrium”) as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, South Carolina 29926.

Q. On whose behalf are you submitting this Direct Testimony?

A. I am submitting testimony on behalf of Columbia Gas Pennsylvania, Inc. (“Columbia” or the “Company”).

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

A. I prepared and am sponsoring the Company’s proposal for a more cost-based rate design by increasing fixed cost recovery through fixed charges, including support for its Weather Normalization Adjustment (“WNA”) and Revenue Normalization Adjustment (“RNA”) mechanisms.

Q. Please describe your educational background and professional experience.

A. Exhibit JDT-1 contains background information summarizing my education, presentation of expert testimony, and other industry-related activities.

Q. Please summarize the content of your testimony.

A. My testimony consists of this introduction section (I) and the following four additional sections:

(II) Cost Structure of the Gas Utility Industry;

(III) Columbia’s Rate Design;

(IV) WNA mechanism proposal; and

(V) RNA mechanism proposal.

II. Cost Structure of the Gas Utility Industry

Q. Please provide some background on the cost structure of the gas utility industry.

A. The gas utility industry is a vital service for residential and business customers alike, providing safe, reliable, and low emission natural gas to fuel gas heating and gas-powered appliances as well commercial and industrial processes. In order to provide this service, natural gas utilities must plan and design the system to meet the peak requirements of customers, often referred to as the “Design Day” of the system. The design day criteria determine the maximum amount of natural gas required to serve customers during peak requirements – the single design day demand. The design and construction of the system to meet the design day criteria is entirely a fixed cost investment in infrastructure allowing for the safe and reliable operation of the system.

Q. Please expand on the concept of design day.

A. A natural gas design day refers to a hypothetical day used by utilities to plan for extreme cold weather conditions. On this day, the temperature is expected to be colder than all but one day in a specified number of years (i.e., once in 30 years). This concept helps utilities ensure they can meet the high demand for natural gas during such extreme conditions and satisfy demand on any given day that is at, or warmer than, the extreme cold weather condition threshold.

1 Some key points regarding design day are:

- 2 • Purpose: It helps utilities plan and ensure they have enough infrastructure
3 and supply to meet peak demand during extremely cold weather.
- 4 • Temperature Estimation: The design day temperature is estimated using
5 statistical methods to predict the coldest temperatures that might occur.
- 6 • Demand Forecasting: Utilities forecast the upper bound of natural gas
7 demand based on the design day temperature to ensure they can meet
8 customer needs.
- 9 • Risk Management: Balancing the cost of infrastructure with the risk of
10 demand exceeding capacity is crucial. Utilities and regulatory commissions
11 agree on the level of risk and corresponding design day conditions.
- 12 • Outcome: This planning is essential to avoid shortages and ensure reliable
13 service during the coldest parts of winter.

14 **Q. What is the difference between demand and energy?**

15 A. In the context of a natural gas utility, demand and energy refer to different aspects of
16 gas usage. Demand refers to the rate at which natural gas is consumed at any given
17 moment. Peak Demand is the highest rate of gas consumption observed over a short,
18 specific period, often during extreme weather conditions when heating needs are
19 highest and is important to the planning and design of the system, as utilities need to
20 ensure they have the capacity to meet peak demand to avoid shortages and maintain
21 reliable service.

1 Conversely, energy refers to the total amount of natural gas consumed over a
2 long period and is analogous to the consumption or cumulative usage of natural gas
3 over time. Another way to think about this is that energy is demand summed over
4 time.

5 In summary, demand is about the rate of usage at a specific time, while energy
6 is about the total amount used over a period of time. Both are crucial for utilities to
7 manage supply and infrastructure effectively; however, of paramount understanding
8 is that demand sets the limit on the amount of usage that can occur at any given
9 moment, and the fixed cost investment in the infrastructure to meet this demand
10 does not change as a result of actual gas flow on the system.

11 **Q. Do you have a simple example demonstrating the difference between**
12 **demand and energy for a gas utility?**

13 A. Yes. Consider two scenarios. The first scenario is a neighborhood of ten homes, each
14 with a gas furnace that, when running at full capacity, consumes natural gas at a rate
15 of 100 cubic feet per hour. If, on a particularly cold winter morning, all ten furnaces
16 run at full capacity for an hour, 1,000 cubic feet of gas is consumed. The second
17 scenario is that on a mild day, only one of those ten furnaces is activated as not all
18 customers will heat their homes on a mild day. The single furnace is activated and
19 operated at full capacity for ten hours. In this second scenario, once again 1,000
20 cubic feet of gas is consumed. The first scenario is much more expensive for the
21 utility to serve because it requires ten times the amount of upstream capacity to meet
22 the demand of all ten customers running their furnaces simultaneously when

1 compared to the second scenario, where only a single furnace is run over a longer
2 period of time but requires only one tenth the capacity to serve the customer
3 consuming the same amount of energy.

4 **Q. How does this relate back to the design of the system and how the system**
5 **is utilized?**

6 A. The design day analysis determines the peak demand used to design the natural gas
7 delivery system. Once the system is designed to meet this level of peak demand, the
8 system can be operated to provide natural gas to utility customers. Rarely will the
9 system deliver the volumes established in the design day analysis to customers – and
10 this is intentional given the design day criteria is a high impact, low frequency event.
11 However, the ability to provide this level of demand is the safeguard that when these
12 events do occur, however infrequent, the utility is able to supply critical gas to its
13 customers. Throughout the remainder of the time, the system will be used at less than
14 full capacity. Consider again the example above, even though in the second scenario
15 only one of the ten customers was using the furnace, because of the system design
16 day planning, all ten customers could have run their furnaces simultaneously.
17 Therefore, all ten customers are receiving the same level of reliable service and access
18 to gas on demand regardless of actual utilization – and this comes at a cost that does
19 not vary with actual consumption. Consequently, all ten customers should pay the
20 same contribution to fixed costs for the system and the only difference in their bills
21 should be related to the actual differences in natural gas consumed (i.e., if one
22 customer wants to heat their home during a mild day then their higher bill would

1 reflect the additional gas consumed to heat their home while paying the same portion
2 of the system investments).

3 **Q. What is your conclusion from the preceding discussion?**

4 A. Aside from the commodity cost of natural gas itself, the natural gas utility system is
5 a fixed cost system. These costs are incurred to design and construct a natural gas
6 delivery system capable of meeting the combined peak demand of all customers on
7 the system under extreme cold weather conditions. Through this design, the system
8 is also capable of being operated to deliver any volume of gas at or below the design
9 day condition on a day-to-day basis based on the needs of the customers. However,
10 the cost of the delivery system does not decrease when customers consume less gas
11 during warmer weather – the only decrease in cost is the reduction due to smaller
12 quantities of the commodity being consumed, which does not impact capacity costs.
13 Consequently, rates should be designed in a way that reflects the fixed-cost nature of
14 the system in that fixed-costs should be recovered through fixed charges, just as is
15 done for almost all other household costs, which I discuss later in Section III.B of this
16 testimony.

17 **III. Columbia's Rate Design**

18 **Q. What is Columbia's vision for its rate design and what guiding principles**
19 **inform that vision?**

20 A. Columbia's rates and riders seek to balance a number of policy objectives for its
21 customers while providing the Company the ability to recover its prudently incurred
22 costs and an opportunity to earn its authorized rate of return. The rate design

principles below draw heavily upon the “Attributes of a Sound Rate Structure” developed by James Bonbright in Principles of Public Utility Rates.¹ Each of these principles plays an important role in analyzing the rate design proposals of Columbia and provides a roadmap that helps guide utilities and regulators when considering how to achieve utility rates that are fair, efficient and practical. In addition, these principles are consistent with Pennsylvania practice and precedent, including the *Lloyd* decision,² where the Commonwealth Court indicated that cost of service is the “polestar” of ratemaking but that other factors, including those listed above, can be considered as well. The foundation of rates should include:

- **Fairness:** Rates should be fair to all customer classes, avoiding undue discrimination.
- **Efficiency:** Rates should promote the efficient use of resources and encourage conservation while avoiding undue restriction of economic use.
- **Simplicity:** Rates should be simple and understandable for customers.
- **Stability:** Rates should provide bill stability for customers and revenue stability for the utility.
- **Reflective of Costs:** Rates should reflect the cost of providing service to different customer classes.
- **Revenue Sufficiency:** Rates should generate enough revenue to cover the utility’s costs, including a reasonable return on investment.

¹ James Bonbright et al. Principles of Public Utility Rates, Public Utilities Reports, Inc. 2nd Edition, 1988.

² *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *appeal denied*, 591 Pa. 676, 916 A.2d 1104 (2007).

1 To achieve these considerations, the Company envisions a rate design that
2 aligns its revenue allocation and rate design with its cost of service (i.e., cost-based
3 rates). In doing so, this will better ensure that customers are paying for their cost of
4 energy services and result in Company rates that are more equitable, understandable,
5 lead to more stable utility bills, and send the appropriate price signals to customers,
6 which also promotes rational conservation.

7 From the perspective of the customer, cost-based rates provide a more reliable
8 means of determining future levels of natural gas costs. If rates are based on factors
9 other than the cost to serve, it becomes much more difficult for customers to translate
10 expected utility-wide cost changes, such as expected increases in overall revenue
11 requirements, into changes in the rates charged to particular customer classes and to
12 customers within the class. For larger customers, this situation reduces the
13 attractiveness of expansion, as well as continued operations, in the utility's service
14 territory because of the customer's limited ability to plan and budget for future
15 natural gas costs.

16 From the perspective of the utility, when rates are closely tied to costs, the
17 impact on the utility's earnings due to changes in customer usage patterns will be
18 minimized. Rates that are designed to track changes in the level of costs result in
19 revenue changes that mirror cost changes. Thus, cost-based rates provide an
20 important enhancement to a utility's earnings stability and alignment between
21 revenue collection and costs incurred. A key element within cost-based rate design
22 is a Straight-Fixed-Variable ("SFV") characteristic, which perfectly aligns fixed costs

1 - costs that do not change with energy usage - with fixed charges and variable costs -
2 costs that do change due to energy usage - with variable charges. A SFV rate design
3 reduces volatility and reduces the need for certain tracking mechanisms such as the
4 WNA (I will discuss this further later in my testimony at Section IV). However, the
5 Company recognizes that this vision is a departure from current practice and should
6 be implemented over the course of a few rate proceedings.

7 **Q. Please summarize the rate design changes Columbia proposes in this**
8 **rate proceeding.**

9 A. In general, Columbia's rate design strategy is to update rates to be more cost-based,
10 to better reflect the Company's cost of providing natural gas distribution service to its
11 customers by increasing the recovery of customer- and demand-related costs through
12 fixed charges.

13 The current residential fixed charge of \$17.25 per month recovers 59% of
14 customer-related costs, resulting in volumetric rates that exceed the cost of providing
15 gas distribution services. The Company proposes monthly customer charges at levels
16 that reflect movement toward each customer class's full customer-related cost
17 responsibility with a corresponding adjustment to volumetric rates. The Company
18 utilized the Customer Based Costs analysis from the Allocated Cost of Service
19 ("ACOS") to identify costs related to providing both monthly distribution service to
20 customers (customer-related costs) and annual levels of distribution capacity
21 (demand-related costs). The level of customer-related costs for the Residential class

1 in the Unit Cost Analysis is \$29.43 per customer per month and the combined
2 customer- and demand-related costs are \$77.16 per customer per month.³

3 For Commercial and Industrial (“C&I”) customers, the Company proposes to
4 increase both the monthly customer charge and the volumetric rate in the same
5 proportion as the proposed increase for each C&I rate schedule.

6 **Q. Why is setting customer charges in alignment with the fixed cost of**
7 **service an important outcome of ratemaking?**

8 A. These proposed customer charges help reduce customer bill volatility, alleviate a
9 significant portion of the instability in the Company’s margin recovery, are fair to
10 customers, are easily understood, convey more appropriate price signals with respect
11 to recovery of fixed distribution costs, benefit low-income customers that have higher
12 than average use, and are not regressive in application to low-income customers who
13 may have little control over their use of energy by recovering more in volumetric
14 charges.

15 Establishing higher monthly fixed charges helps to equalize the contribution
16 each customer within a class makes towards recovery of the fixed costs attributable
17 to the class. This method of cost recovery is preferable to including such costs in the
18 volumetric block prices, which has the effect of causing some customers to pay too
19 much while others pay too little.

20 The fixed customer charges provide for recovery of a portion of the Company’s
21 fixed costs, which are incurred solely because of the existence of customers connected

³ Exhibit 111, Schedule 2, pages 16 and 25

1 to the system. These costs, such as the expense of reading meters and billing, occur
2 regardless of the amount of natural gas used. The proposed customer charge
3 increases will also help to ensure recovery by the Company of a greater portion of its
4 fixed costs of providing service. Inasmuch as costs are not related to usage, they
5 should be recovered to the extent possible through a tariff mechanism that does not
6 depend upon volumetric billing.

7 In terms of understandability, customers easily understand fixed cost charges
8 and are used to these pricing structures in their everyday lives. Because these costs
9 do not vary with the customer's usage, it is perfectly understandable that the charge
10 should not vary as well. It is intuitively obvious that a customer should not pay more
11 for being a customer when the weather is hot and conversely should not pay less when
12 the weather is cold.

13 **Q. What criteria were utilized to determine that a \$31.97 customer charge**
14 **for the residential customers is appropriate?**

15 A. The residential class does not have a demand charge, so all distribution margin
16 revenues are recovered through either the monthly customer charge or the
17 volumetric charge. This is nearly universal across the utility industry, where some
18 commercial and industrial rate classes may have demand charges but rarely are they
19 present or introduced for residential customers. Introducing a demand charge for
20 residential customers is not viable given current billing processes, and concerns
21 relating to administrative billing complexity and customer understanding. Given the
22 discussion above relating to the fixed cost nature of Columbia's costs and the usage

1 pattern of low-income customers, the Company is proposing a higher customer
2 charge, balancing the principles of rate design earlier discussed (e.g., fairness,
3 stability, and consumer rationing/economic efficiency). After reviewing the current
4 customer charge for residential customers of \$17.25 and the relative unit cost for
5 customer-related and demand-related costs, it is reasonable to move to a \$31.97
6 monthly customer charge for residential customers. This allows some of these fixed
7 distribution costs to be recovered through a fixed monthly customer charge rather
8 than a volumetric charge, without introducing a demand charge for residential
9 customers. The \$31.97 customer charge was derived by recovering the proposed
10 increase to the residential class fully from the customer charge with only a modest
11 change to the volumetric charge to account for rounding.

12 **Q. Why is an increase to the customer charge important?**

13 A. This becomes particularly important when a customer considers different options
14 relating to alternative fuels and investments in conservation and energy efficiency, as
15 these decisions are fundamental functions of usage. These decisions can be distorted
16 when non-usage-related fixed costs are collected on a usage basis. Further, without
17 proper price signals, the economic markets that comprise materials, goods, and
18 services that are inputs and outputs to energy products and services are distorted. As
19 such, companies and people cannot make the proper decision to maximize their
20 preferences on allocating their limited resources of time and money. It is
21 economically inefficient when fixed distribution costs are recovered on a usage basis,
22 and customers implement energy efficiency measures reducing their contribution to

1 fixed costs with no corresponding reduction in the fixed costs of providing service.
2 In short, incorrect pricing results in an incorrect price signal for which consumers
3 may act, resulting in savings for a customer that do not align with decreased costs to
4 the system. A misalignment such as this results in economically inefficient outcomes
5 where individual consumer savings do not result in societal savings, skewing markets
6 in a manner that results in subpar outcomes.

7 **Q. How will the Company's proposal impact the average low-income**
8 **customer?**

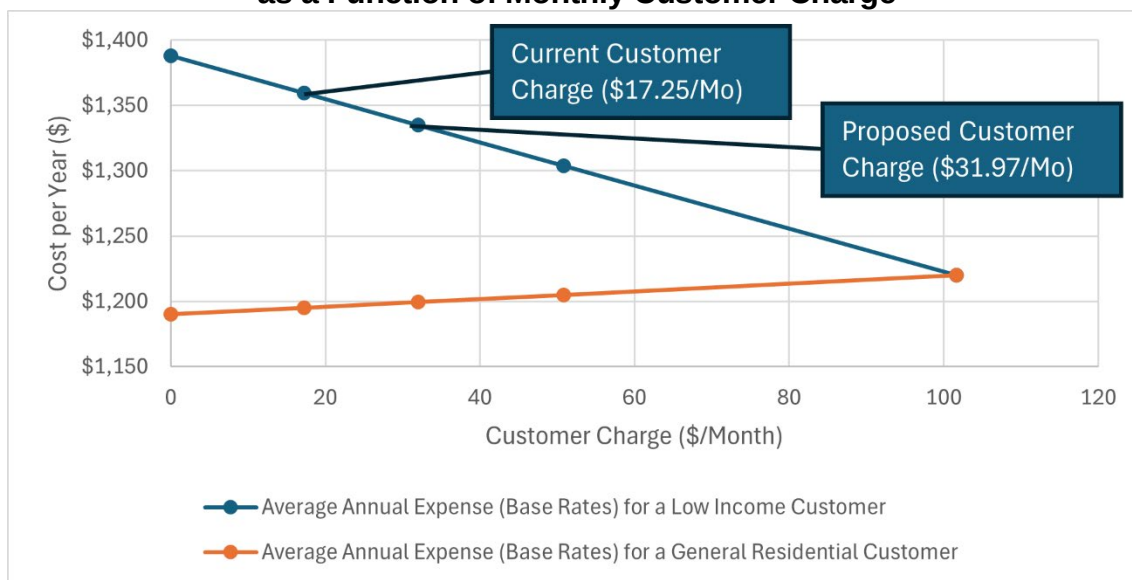
9 A. Since the average low-income customer uses more natural gas than the average
10 residential customer, increasing the customer charge will decrease the annual base-
11 rate utility expense for the average low-income customer. This is depicted below in
12 Table 1, which shows the average annual base-rate utility cost using the Company's
13 proposed revenue requirement at different combinations of customer and volumetric
14 charges designed to recover the proposed revenue requirement. As shown in the
15 table, the expected cost for an average low-income customer decreases by
16 approximately \$24 dollars per year under the Company's proposal. A move to SFV
17 would save the average low-income customer approximately \$139 per year. SFV also
18 would have all residential customers paying the same contribution to fixed costs to
19 access the same reliable natural gas utility system.

20

21

22

**Table 1: Average Base-Rate Customer Cost
as a Function of Monthly Customer Charge**



A. Residential Customer Class Characteristics

Q. Did you review the usage characteristics of the residential class to inform the Company's proposed rate design?

A. Yes. Prior to making any decisions and forming recommendations related to the design of rates for the residential class, I performed a detailed review of customer class usage characteristics. Specifically, I was provided with two years (2023 and 2024) of monthly residential customer data. Also included within this data were key characteristics of the customers that allowed me to identify subsets of the residential population for more in-depth comparative analytics related to low-income ("LI") customers (customers who have provided the Company verbal or documented proof of household income being equal to or less than 150% of the Federal Poverty Income

Guidelines) compared to the rest of the general residential (“GR”) customer population.

Q. Please summarize your key findings.

A. Of particular interest, the result of my analysis demonstrates that LI customers tend to consume more natural gas than the rest of the GR population. Both populations have a positive correlation of energy usage to income; however, the LI customers have a higher average use and increased rate of consumption relative to income when compared to the GR customers. While the purpose of my analysis is not to attribute a cause-and-effect relationship to these findings, one noteworthy characteristic that was uncovered was that the LI customers tended to have higher energy consumption per square foot. I have summarized this information in Table 2 below.

Table 2 – Residential Average Usage by Group

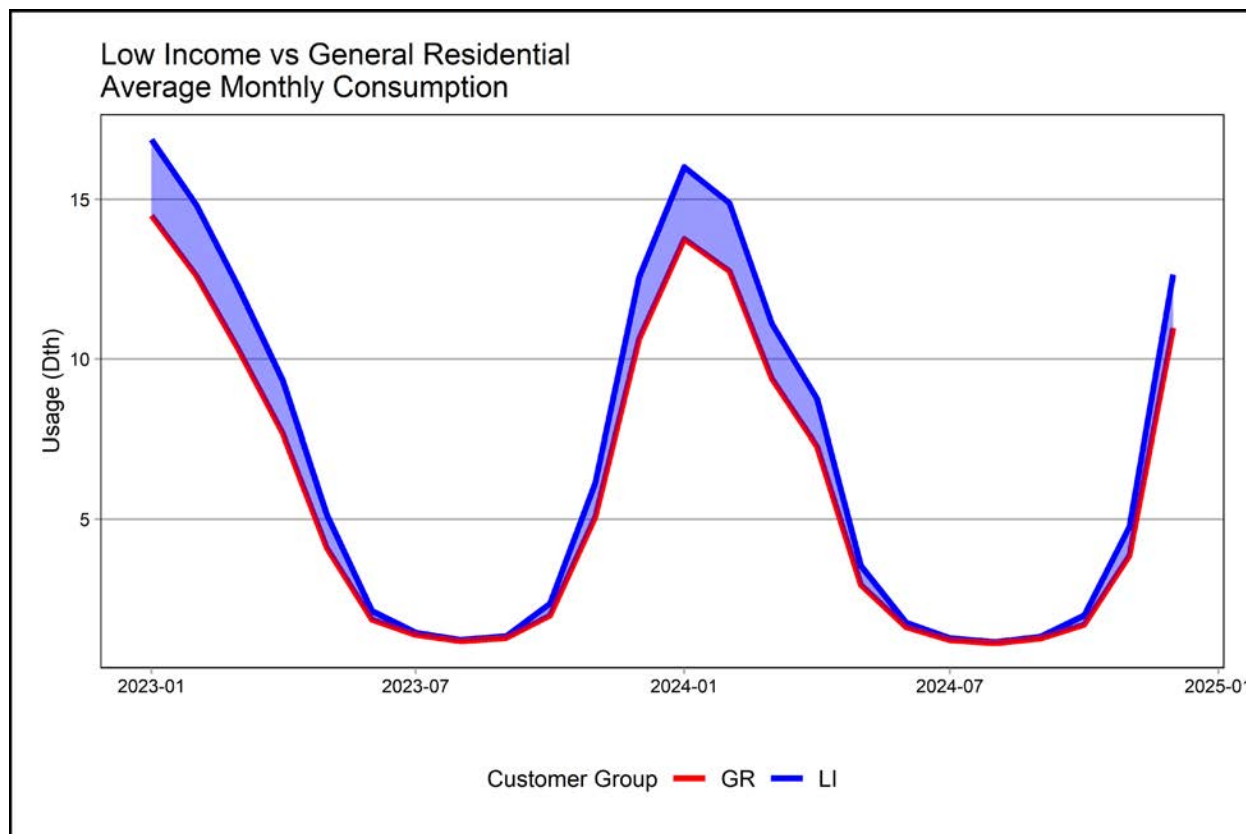
Year	Customer Group	No. of Customers	Average Monthly Usage (Dth)	Average Living Area (Sq. Ft.)	Average Monthly Energy Intensity (Dth/Sq. Ft.)
2023	Low Income	60,559	7.09	1,501	0.0047
2023	General Residential	347,976	6.05	1,692	0.0036
2024	Low Income	63,188	6.55	1,512	0.0043
2024	General Residential	347,023	5.65	1,687	0.0034

Q. Can you describe the analysis and results in more detail?

A. Yes. Some of this information becomes easier to understand through a graphical representation as well. Most of the initial work centered around joining data stored within different systems at Columbia. The Company provided individual customer billing records from the Company’s billing system, Geographic Information System (“GIS”), and property record data from the GIS database, identification of low-

1 income customers and disclosed incomes of both low-income and some general
2 residential customers, and weatherization program participation through the
3 Company's Universal Services team. This was combined with other information
4 regarding the Company's rate schedules and service territory. Once the multiple
5 sources of data were combined into a single dataset, the next step was to validate
6 some of the data characteristics, such as number of customer bills, back to previous
7 data summaries prepared by the Company for use in the 2024 rate proceeding. Once
8 that was completed, the data was analyzed for the total residential class and the
9 subgroupings to assess the following characteristics: average usage, monthly usage,
10 and usage per square foot of living space. As shown in Table 3, it is evident that while
11 the pattern of usage (that is the seasonality characteristics) is very similar between
12 the LI and GR customers, the actual levels of consumption differ whereby the LI
13 customers tend to use more gas than GR customers, especially during the heating
14 months. The blue shading is added where the LI customer usage exceeds the GR
15 customer usage.

Table 3 – Residential Usage Patterns by Group

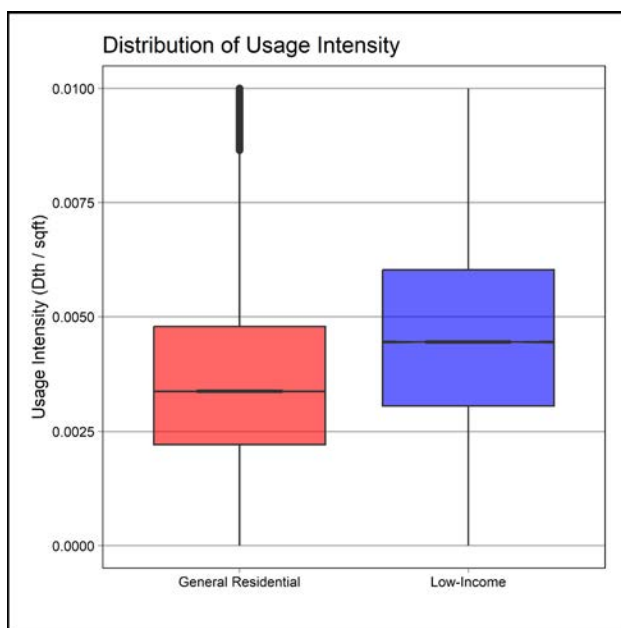


Q. You also mentioned analyzing usage per square foot of living space, please elaborate further.

A. The next set of results, presented in Table 4 below, shows the usage intensity per square foot of living space. The Company subscribes to a data service to obtain tax assessor data for addresses within its service territory from a third-party data provider. This data includes, among other data points, the living square feet for many (though not all) of the addresses in the service territory. Using this information, insights regarding how the differences in the energy intensity of households between the LI and GR customer segments is estimated. The energy intensity analysis

revealed that the LI customer segment tends to experience higher energy intensity per square foot compared to the GR customers, reinforcing the potential benefits of the Company's weatherization program that can impact the efficiency and energy intensity of dwellings.

**Table 4 – Residential Energy Intensity:
Usage per Square Foot of Living Space**



Q. What do you conclude from this analysis?

A. The usage characteristics of Columbia's residential customers demonstrate a similar usage pattern for most customers with an observable seasonal trend for gas heating. This characteristic is present both for LI customers and GR customers. A key difference is the level of average usage between these two customer segments with the LI customers using, on average for both 2023 and 2024, approximately 17% greater volumes of gas than the GR customers and the differential are proportional

1 to overall usage on a monthly basis. This means that during the heating months, the
2 LI customers are experiencing greater volumes than the GR customers and can see a
3 greater seasonal volatility of bills due to the volumetric rate design. Upon
4 examination, one potential cause for these phenomena is that the LI customers
5 experience a usage per square foot of living space that is approximately 31% greater
6 than the GR customers, indicating the energy intensity of LI dwellings are higher
7 (e.g., less efficient, different household sizes/demographics). Taking all of this
8 information together, along with continuing the Company's weatherization and other
9 low-income programs, indicates that another way to aid the LI customers is to reduce
10 the amount fixed costs recovered through the volumetric charge as much as possible.

11 **B. Household Budgeting**

12 **Q. In Section III of your testimony, your concluding remarks touched on**
13 **typical household costs being fixed in nature, can you expand on this**
14 **statement?**

15 A. Yes. The vast majority of household expenses are fixed costs that allow for easier
16 budgeting by households. For example, following is a list of common household
17 expenses that are typically paid as a fixed monthly charge:

- 18 • Mortgage or Rent: Monthly payments for your home.
- 19 • Property Taxes: Often included in mortgage payments or paid separately.
- 20 • Homeowners or Renter's Insurance: Regular premiums for protecting your
21 home and belongings.
- 22 • Internet and Cable: Monthly fees for internet and cable television services.

- 1 • Phone Bills: Costs for landline or mobile phone services.
- 2 • Car Payments: Monthly installments for car loans or leases.
- 3 • Car Insurance: Regular premiums for vehicle insurance.
- 4 • Health Insurance: Monthly premiums for medical coverage.
- 5 • Subscriptions: Fees for services like TV streaming platforms, magazines, or
- 6 memberships.
- 7 • Day Care / Child Care / Tuition: Monthly fees for childcare, school, etc.

8 These expenses are paid through fixed monthly or periodic charges. Additionally,
9 another characteristic of these services is that the expenses, for the most part, must
10 be paid ahead of (or contemporaneously with) the delivery of the service, not after
11 the fact.

12 Not included in this list are expenses for electric, gas, and water utility bills (while
13 cable and internet are included), food, vehicle fuel, entertainment, and other
14 discretionary expenses.

15 **Q. How does the proposed customer charge for residential customers**
16 **compare to similar fixed fees for other essential services?**

17 A. The proposed increase in the customer charge aligns with the structure of other
18 essential services that customers regularly pay for such as internet, TV, and mobile
19 phone services. These industries typically charge flat monthly fees that cover
20 infrastructure, maintenance, and service availability, regardless of usage levels.

21 For example, a standard internet service plan in the Pittsburgh area often

1 includes a fixed charge of \$30 to \$85 per month⁴, covering network access,
2 equipment fees, and customer support, regardless of how much data is used.
3 Similarly, cable or streaming TV service providers charge a flat monthly fee ranging
4 from \$53 to \$155⁵ for service availability, with tiers based on the number of channels
5 included. Cellphone services also follow a similar model, where customers pay a fixed
6 monthly fee ranging from \$30 to \$100⁶ for access to the network, customer support,
7 and device financing, even if their usage varies month to month. Natural gas service
8 operates similarly, requiring a stable infrastructure to ensure uninterrupted service
9 to all customers, regardless of individual usage patterns.

10 **Q. Do gas utility bills stand out as an exception to the remainder of the non-**
11 **fixed monthly expenses?**

12 A. Yes. The utility costs, as I described earlier in my testimony, are predominantly fixed
13 costs, the only variable component is the natural gas commodity itself. This is
14 analogous to a number of items above. Most notably, car payments or lease payments
15 provide access to a vehicle but in order to drive it, one must still pay the variable fuel
16 cost. This is virtually identical to the fixed and variable components of the utility
17 system, whereby the fixed costs provide customers access to a reliable utility system
18 capable of delivering natural gas reliably upon demand from any customer, and the
19 variable cost covers the fuel needed when a customer desires to use the system.

⁴ Xfinity (cable) \$30-\$75 per month; T-Mobile Home Internet (fixed wireless) \$50 per month; Verizon Fios (fiber) \$34.99-\$84.99 per month.

⁵ Xfinity (cable) \$53.10 to \$122.10 per month; DirectTV (satellite) \$74.99-\$154.99 per month.

⁶ Verizon \$30 to \$55 per month; AT&T \$35.99 to \$50.99 per month; T-Mobile \$50 to \$100 per month.

1 However, the Company's current rate design does not recognize this fact and places
2 fixed cost recovery in a variable use charge.

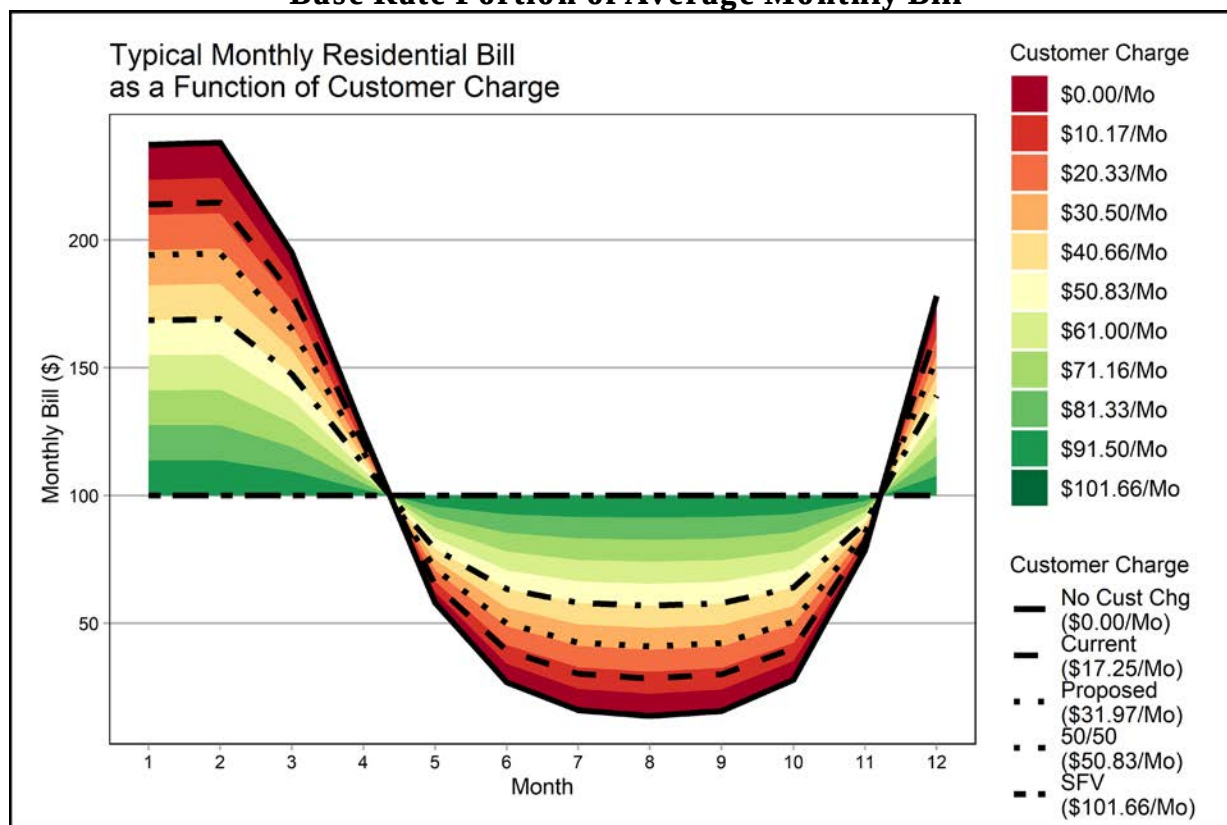
3 The remainder of the items listed as non-fixed costs are still known costs but
4 are completely discretionary in terms of the magnitude of the expense. It is
5 completely within control of the household how much entertainment expense is
6 budgeted and what it is spent on, how much money is used to go out to eat rather
7 than cooking at home, etc. A key difference for these items when compared to utility
8 bills relates to the utility's obligation to serve and the fixed expense incurred
9 associated with that obligation.

10 **Q. Do fixed monthly charges allow for greater predictability in household**
11 **budgets?**

12 A. Yes. Aligning the utility bills to mimic the way those costs are incurred (similar to car
13 payments and vehicle fuel) will provide a greater understanding of utility bills, reduce
14 volatility, and allow for easier household budgeting due to the enhanced
15 predictability of utility service costs. Further, it is important to note the increasing
16 desire of consumers who subscribe to these discretionary expenditures to set a fixed,
17 known budget and receive a fixed, known amount of service (e.g., food/meal
18 subscription services, clothes subscription services, monthly car wash membership,
19 etc.). Table 5 below shows the average monthly bill for base rate costs for a typical
20 residential customer under a range of revenue neutral customer and volumetric
21 charge combinations. As fixed recovery increases, not only do all residential

customers pay an increasingly similar amount to access the same reliable natural gas system, their bills become more consistent from month to month.

**Table 5 – Residential Monthly Bill Fluctuations:
Base Rate Portion of Average Monthly Bill**



Q. Please expand on why higher customer charges would benefit low-income customers.

A. There is a common misconception that low-income customers are low-usage customers. This is not a correct characterization of low-income customers who are indeed higher-use customers. As the data analysis previously discussed shows, the 2024 average use for a LI customer is 78.65 Dth/year. This is 16% higher than the 2024 average GR customer use of 67.83 Dth/year.

1 Also, all else equal, higher customer charges necessitate lower variable
2 charges. The collection of costs through fixed or volumetric charges is the only means
3 of collecting the revenue to cover costs for a specific customer class. The amount of
4 total revenue target for the class does not change, just which component is designed
5 to recover what portion of the total revenue target. Higher usage customers pay more
6 when more fixed customer costs are embedded in the volumetric rates. This creates
7 a social equity concern, as customers who can afford to reduce their usage through
8 energy efficiency investments can decrease their bills by making such investments,
9 while those customers who cannot afford to make energy efficiency investments will
10 see increases in their bills. Examples of those who could possibly afford to reduce
11 their usage include higher-income households who can undertake more expensive
12 energy efficiency measures or through a living situation such as a single individual
13 versus a family with infant children.

14 Further, recovering fixed costs in volumetric charges places regressive
15 burdens on low-income households who have to make decisions to reduce their gas
16 usage that impact their quality of life. Recovering fixed costs in volumetric charges
17 increases the burden on some vulnerable households during the coldest months,
18 forcing some households to make tough decisions. These households might choose
19 between gas use for basic human needs, such as heat, hot water and cooking or other
20 choices that add value to their lives (i.e., food, medical care, clothing, personal care
21 products).

1 Last, considerations relating to the intersection of income and rate design
2 would be amiss if they did not include discussions relating to Columbia's low-income
3 programs, which are discussed by Company witness Nicole M. Paloney. Columbia
4 offers a suite of targeted low-income programs, beyond the Company's Customer
5 Assistance Program ("CAP"), such as, the Emergency Repair Program, Security
6 Deposit Assistance Fund, Low-Income Usage Reduction Program, WarmWise Audits
7 and Rebates Program, and Customer Assistance Referral and Evaluation Services
8 ("CARES").⁷ There is no reason to send the wrong price signal to all customers when
9 the impacts on low-income customers are mixed (i.e., their ability to respond to
10 higher variable charges, the lower quality of living they may choose in response to
11 higher variable charges, and low-income customers with higher than average usage
12 will disproportionately be impacted by higher variable charges) and when there are
13 robust programs in place that target bill and weatherization assistance for low-
14 income customers.

15 **Q. Please expand on the social inequity and regressive nature of recovering**
16 **fixed costs in a volumetric charge.**

17 A. When certain aspects that drive how and when a customer uses energy are more
18 rigid, it limits how those customers can shift and/or reduce energy consumption -
19 such as a rental tenant not being able to alter the appliances or weatherize/improve
20 insulation in a dwelling. In this case, the tenant has no choice but to accept the

⁷ Company's Website: [https://www.columbiagaspa.com/bills-and-payments/financial-support/income-eligible-assistance-programs#:~:text=Customer%20Assistance%20Program%20\(CAP\).at%20hardshiptools.org/MyApp](https://www.columbiagaspa.com/bills-and-payments/financial-support/income-eligible-assistance-programs#:~:text=Customer%20Assistance%20Program%20(CAP).at%20hardshiptools.org/MyApp)

1 inefficiencies of the rental. Also, the number and nature of household members
2 impacts flexibility, which limits the ability of customers to respond to volumetric
3 rates. It is also important to note that low-income households tend to choose to
4 respond to volumetric prices by reducing their energy load to save money, at times
5 when energy is most important to their standard of living. In July 2024, JPMorgan
6 Chase released a research paper that analyzed how households manage their
7 electricity bills and other spending when faced with hot weather. The primary finding
8 is that “low-income households primarily manage high electricity bills in hot months
9 by using less air conditioning and enduring more heat (and) the health costs of under-
10 cooling likely exceed the amount households save on their electricity bills.”⁸ The
11 same logic and implications apply to low-income households faced with volumetric
12 charges for gas distribution service during periods of cold weather. The report also
13 reiterates the points I made above that low-income homeowners may find it difficult
14 to make energy efficiency and weatherization investments because of the high
15 upfront costs, and “low-income renters are very unlikely to make these investments
16 because the value of the capital investment will accrue to the landlord.”⁹ This usage
17 relationship is evidenced in an article by the U.S. Department of Energy that outlines
18 high consumption as a key factor to the energy burden placed on low-income
19 households.¹⁰ In short, recovering fixed costs in a volumetric charge places an undue

⁸ JPMorgan Chase & Co. (July 18, 2024). *How households manage high air conditioning bills*. Retrieved from <https://www.jpmorganchase.com/institute/all-topics/financial-health-wealthcreation/how-households-manage-high-air-conditioning-bills>

⁹ *ibid.*

¹⁰ *Low-Income Household Energy Burden Varies Among States — Efficiency Can Help In*

burden on low-income customers, who use more than average energy and choose to respond in ways that reduce their standard of living, resulting in social inequities and regressive outcomes with no benefit to other ratepayers, society, or the Company.

Q. Have other jurisdictions recently recognized the impact of recovering fixed costs through volumetric charges on low-income customers?

A. Yes. Most recently, in its order in Cause No. 45990 issued on February 3, 2025, the Indiana Utility Regulatory Commission recognized the following:

(...) we are persuaded by witness Taylor's evidence that frequently low-income customers are harmed by recovery of fixed costs through a volumetric charge. We are further persuaded that the TDSIC [Transmission, Distribution, and Storage System Improvement Charges] distribution costs should continue to be recovered through a fixed charge. These are fixed costs, and recovery through a volumetric charge would send inefficient price signals and would work to the detriment of those low-income customers who are higher volume users. [Section xi.6, Commission Discussion and Findings, page 113]

Q. Has the Company prepared a detailed comparison of the Company's present and proposed rates and resulting revenues by rate class?

A. Yes. Columbia Exhibit No. 103, Schedule No. 8 – Allocation of Proposed Annual Revenues by Rate Schedule Based on Revenue Requirement, sponsored by Company witness Kevin L. Johnson, presents a detailed comparison of present and proposed revenues for each of Columbia's rate classes.

IV. WNA mechanism proposal

1 **Q. What is the Company proposal regarding WNA in this proceeding?**

2 A. Columbia is requesting the Commission to approve the current pilot WNA
3 mechanism as a permanent program.

4 **Q. What is the WNA?**

5 A. The WNA is a method of adjusting the delivery portion of a customer's bill to reflect
6 "normal" weather conditions rather than actual weather. It helps mitigate the impact
7 of unusually cold or warm weather on customer bills during the heating season,
8 which runs from November through May.

9 **Q. Why is the WNA necessary?**

10 A. First, the WNA is similar to the Purchased Gas Cost ("PGC") rider, which ensures
11 neither customers nor the utility are harmed from fluctuations in the cost of the
12 natural gas commodity, a cost that is outside the control of the utility. In parallel, the
13 WNA is intended to ensure neither customers nor the utility are harmed from
14 deviations in revenue recovery and costs paid associated with fluctuations in weather
15 sensitive usage – another source of uncertainty outside the utility's control (i.e. the
16 utility cannot control weather, and weather varies from normal each year). The
17 second contributing factor is the Company's current rate design in place which seeks
18 to recover significant fixed costs through a usage-based charge, especially from highly
19 weather sensitive customers. Taken together, these two characteristics necessitate
20 the use of a WNA mechanism, otherwise Columbia would not be afforded a rate
21 structure that provides a fair opportunity to recover its Commission approved

1 revenue requirement, and in instances where weather is colder than normal,
2 ratepayers would pay more to the utility than its cost to serve.

3 **Q. Is it fair to interpret from your statement above that if either actual**
4 **weather each year was the same as normal weather used to establish**
5 **rates or the Commission were to approve rates with all fixed costs**
6 **recovered in fixed rates, the WNA would not be necessary?**

7 A. Yes, that is correct.

8 **Q. Please describe the relevant factors for the Commission to determine**
9 **that the Company's WNA is just and reasonable.**

10 A. Each policy factor relevant to the Commission's evaluation is discussed below, along
11 with the specific impact of Columbia's WNA on each consideration. The following
12 fourteen items align with the considerations identified within the Statement of Policy
13 as outlined by the Commission in the alternative rate making Docket No. M-2015-
14 2518883.

- 15 1. **Alignment with Cost Causation Principles:** The Company's WNA is
16 designed to recover distribution revenues needed to satisfy the cost-of-service
17 requirement determined in this proceeding, while mitigating the variance between
18 actual and projected distribution revenues due to weather. The Company recovers
19 a significant portion of fixed costs through volumetric rates. These fixed costs do
20 not vary with the amount of gas delivered to customers and are composed of fixed
21 operation and maintenance expenses, administrative and general expenses,
22 depreciation, certain taxes, a portion of working capital requirements, and return

1 on investment. These costs also do not vary in the short-term with changes in
2 temperature. In the absence of a rate design that affords the Company the
3 opportunity to recover all fixed costs in a fixed monthly charge, the WNA
4 mechanism better aligns distribution revenues with cost causation principles,
5 appropriately accounting for variation in usage due to weather.

6 **2. Impact on Fixed Utility's Capacity Utilization:** The WNA mechanism
7 supports efficient capacity utilization by stabilizing the recovery of fixed
8 distribution costs, which are incurred to maintain Columbia's infrastructure and
9 capacity to serve customers regardless of fluctuations in gas usage. Since these
10 fixed costs do not change with short-term usage variations, the WNA ensures that
11 Columbia can continue investing in the infrastructure necessary to meet peak
12 demand and long-term capacity needs and be compensated for these investments.
13 By supporting revenue stability, the WNA reduces under-recovery risks during
14 periods of lower gas usage, ensuring that the revenues collected align with use of
15 the utility's fixed assets by customers.

16 **3. Reflection of Demand Associated with the Customer's Anticipated**
17 **Consumption:** Customer specific usage factors corresponding to their individual
18 demand is continually updated through the WNA formula and reflects the level of
19 demand associated with the customer's anticipated consumption levels.

20 **4. Limiting Inter-Class and Intra-Class Cost Shifting:** The WNA is customer
21 specific and only applicable to the Residential class; therefore, it does not affect
22 traditional interclass or intraclass cost shifting.

1 **5. Eliminates Disincentive for Promotion of Energy Efficiency and**

2 **Conservation Programs:** The Company's WNA only addresses variations due
3 to weather and does not affect customers' ability to pursue energy efficiency
4 measures. Further, the Company continues and will continue to promote the use
5 of energy efficiency measures to its customers.

6 **6. Customer Incentives for Efficiency and Distributed Energy Resources:**

7 Customers continue to have an incentive to employ energy efficiency measures and
8 distributed energy resources because a reduction in usage still reduces their overall
9 bill and the portion of their bill that is subject to the WNA mechanism.

10 **7. Impact on Low-Income Customers:** Under the WNA mechanism, certain

11 customers enrolled in CAP who pay a "percent of budget bill" see lower bill
12 variability during colder than average periods when gas commodity costs may be
13 higher from increased consumption. In addition, customers who are currently
14 enrolled to pay their bills based on a percentage of their household income see little
15 to no impact to their bills under the WNA mechanism.

16 **8. Rate Stability:** The American Gas Association Gas Rate Fundamentals book

17 (Pages 152 – 156) states: "The goal of stability recognizes historical relationships
18 among customers in terms of the proportion of system costs each customer group
19 bears. Stability leads to a policy of gradualism in rate changes if substantial
20 increases (or decreases) are called for in the context of a single rate case. Changes
21 in gas utility pricing policy should be imposed gradually so that customers can
22 adjust and any adverse impacts on the customers' operation are minimized." The

WNA mechanism provides customers more stable annual bills and directly mitigates volatility in their monthly costs. Customers pay for the costs assigned to the residential volumetric base rate in the most recent rate case and customers do not pay more or less than that amount solely because the actual weather for the month the customers are billed is different than the weather used to determine the rate design of the residential volumetric base rate. Further, the WNA has been on customers' bills for over 10 years and thus will not add another charge to the bill.

9. Interaction with Weather: The Company's WNA adjusts customers' bills due to variations from normal weather during the heating season months (November through May), and it only mitigates the revenue effect of weather on the original rate design of the residential volumetric base rate. Without it, the Company is deprived of the opportunity to recover the Commission-approved distribution costs of service for the Residential class during times when warmer than normal weather occurs, although the WNA does not guarantee 100% recovery of its authorized distribution revenues. Moreover, the absence of a WNA would place the Company in a position of receiving a higher amount of revenues from customers when the weather is colder than normal. The WNA serves to avoid both scenarios by minimizing the impact of weather on the Company's revenues and customers' bills.

10. Impacts on the Frequency of Rate Case Filings and Regulatory Lag: The WNA does not impact the Company's rate case frequency nor does it effect regulatory lag.

1 **11. Interaction with Other Revenue Sources:** Columbia's WNA is solely focused
2 on recovering costs that are part of the base revenue requirement and does not
3 interact with other revenue sources, such as Section 1307 automatic adjustment
4 surcharges, restructuring riders, or system improvement charges under Section
5 1353.

6 **12. Consumer Protections:** Columbia's proposed WNA includes several consumer
7 protections to ensure fairness and transparency, as follows:

8 a. No Over-Recovery of Revenue: The WNA mechanism results in an adjusted
9 bill that reflects the revenues that would be recovered under normal
10 weather, i.e., the same normal weather used to set rates. The Company does
11 not recover additional distribution revenues due to colder than average
12 temperatures that result in higher-than-normal usage from customers.

13 b. No Cross-Subsidization: The WNA only applies to the Residential class.

14 c. Regulatory Oversight: The WNA is subject to Commission review and
15 regulatory reporting requirements to ensure compliance with approved
16 revenue stabilization objectives and to protect consumers from unintended
17 rate impacts.

18 d. Customer Transparency: Columbia provides clear bill disclosures and
19 customer education regarding WNA adjustments, ensuring consumers
20 understand how the mechanism works and how it impacts their bills.

21 **13. Complexity and Customer Understanding:** The WNA is not a new concept
22 to the regulated utility industry. The Company has been billing the WNA since

1 October 2013 without measurable complaints and similar versions have been
2 successfully implemented by other Pennsylvania natural gas distribution
3 companies. The WNA tariff provides detailed information to the customer of how
4 the mechanism works and the adjustments are displayed separately on bills,
5 ensuring full transparency. The Company' has implemented clear customer
6 communications, including bill inserts, an online education portal, and trained
7 customer service representatives to address customer questions.

8 **14. Utility Reliability Improvement Support:** The Company's cost of service is
9 inclusive of investments and costs to continue to enhance the safety and reliability
10 of its system. The WNA helps minimize the volatility of the recovery of these costs.

11 **Q. How is "normal" weather typically defined by the industry?**

12 A. Typically "normal" is defined as the average of some number of historic years. The
13 number of years used in the average varies by utility / jurisdiction but typically is
14 within the range of 10-30 years of historic data. Depending on the use case (demand
15 forecasting or energy forecasting) different types of averages are used (simple versus
16 rank & mean). The common characteristic being it is a historic averaging approach
17 that typically does not account for temperature trends within the data.

18 **Q. How are weather-normalized gas volumes used to derive a gas utility's**
19 **base rates?**

20 A. As part of the rate design in a base rate proceeding, a utility's volumetric unit rates
21 for gas service are derived by dividing the costs to be recovered through volumetric
22 based rates by the anticipated weather-normalized gas sales volumes. These rates are

1 designed to provide the utility with an opportunity to recover the costs it incurs to
2 provide utility service, at the levels determined in the utility's rate case under normal
3 weather conditions. To the extent any costs are subject to recovery in a volumetric
4 charge, the recovery of such amounts is entirely dependent upon the volumes of gas
5 usage experienced by the utility. Therefore, the recovery of costs in a volumetric
6 component of rates will always lead to a difference in recovery of actual costs because
7 actual weather conditions will, by and large, never match the normalized weather
8 conditions used to set rates.

9 **Q. Please explain how fluctuations in weather over time impact a gas**
10 **utility's temperature-sensitive customers and the utility's financial**
11 **performance.**

12 A. Since the bills of gas customers are largely based on the level of gas usage,
13 temperature-sensitive customers' monthly bills can vary widely due to changing
14 weather conditions. Under traditional ratemaking methods, if actual temperatures
15 were colder than normal, the typical gas customer would use more gas, pay more for
16 service (through volumetric charges), and potentially overpay its share of fixed costs.
17 This occurs because the unit rates used to recover fixed costs are not reduced to
18 recognize the higher gas volumes used by customers during colder weather. Since the
19 gas utility's level of fixed costs (which do not include purchased gas costs) does not
20 change with weather, the higher gas volumes applied against the same unit rate
21 would generate comparatively higher distribution revenues than the level of fixed
22 costs established for ratemaking purposes. Conversely, in warmer than normal

1 weather, the reverse situation would occur. Customers' gas usage decreases with
2 warmer temperatures, thus generating comparatively lower distribution revenues
3 than required to recover the gas utility's total fixed costs that do not decrease due to
4 warm weather. This places the customer at risk for overpaying the utility's cost of
5 service during colder than normal periods and the utility at risk for not recovering its
6 full cost of service during warmer than normal periods.

7 **Q. How does the WNA impact customer bills?**

8 A. The WNA adjusts the delivery charge based on deviations from normal weather. If
9 the weather is colder than normal, customers receive a credit to reduce the delivery
10 charge. Conversely, if the weather is warmer than normal, a debit is applied,
11 increasing the delivery charge.

12 **Q. Does the WNA account for 100% of the difference between the normal
13 and actual weather variations?**

14 A. No. The mechanism applies to only seven months out of the year (November through
15 May) and it is currently subject to a 3% deadband.

16 **Q. Why is the WNA beneficial for both customers and the utility?**

17 A. For customers, the WNA reduces bill volatility by preventing extreme fluctuations
18 due to abnormal weather. For the utility, it ensures that delivery costs are recovered
19 in a more stable manner, reducing the financial uncertainty caused by weather
20 variations.

21 **Q. Is the WNA a common practice in the utility industry?**

1 A. Yes, WNA mechanisms are widely used across different jurisdictions to provide more
2 stable and predictable utility bills. Many regulatory commissions recognize a WNA
3 as an effective tool to balance fairness for customers while maintaining the financial
4 stability of the utility.

5 **Q. Has the Pennsylvania Public Utility Commission approved the WNA?**

6 A. Yes, the Pennsylvania Public Utility Commission has approved the use of the WNA
7 as a fair and reasonable method of stabilizing delivery costs and ensuring consistency
8 in billing during the heating season.

9 **Q. Has the WNA mechanism been effective in stabilizing delivery charges**
10 **and reducing the impact of unpredictable weather patterns on customer**
11 **bills?**

12 A. Yes. The WNA has adjusted delivery charges to reflect normal weather conditions
13 rather than actual, sometimes extreme, weather. The goal of providing a smoother
14 and more predictable billing experience has been achieved; for this reason, Columbia
15 believes the WNA mechanism should become permanent.

16 **Q. Have Columbia customers overpaid the Company because of the WNA?**

17 A. No, the WNA does not allow for the Company to collect more than its authorized
18 revenue requirement. In fact, during the last six years, the Company has been unable
19 to recover the revenue requirement authorized by the Commission. This is
20 demonstrated in Table 6, which compares the authorized revenue requirement
21 approved by the Commission to what is recovered through rates, the WNA and any
22 unrecovered amounts.

**Table 6 – Columbia’s Residential Authorized Revenue Requirement
vs. Billed Amounts (in millions)**

Year	(a) Total Authorized Residential Revenue	(b) Actual Billed Base Revenue	(c) Actual Billed WNA	(d) = (b) + (c) Total Actual Billed Base Revenue + WNA	(e) = (d) - (a) Unrecovered Balance
2019	\$290.1	\$283.1	(\$1.5)	\$281.5	(\$8.6)
2020	\$290.1	\$273.0	\$10.9	\$283.9	(\$6.2)
2021	\$334.4	\$326.1	\$3.3	\$329.4	(\$5.1)
2022	\$372.1	\$364.5	\$1.3	\$365.8	(\$6.3)
2023	\$402.8	\$360.6	\$22.0	\$382.7	(\$20.2)
2024	\$402.8	\$343.6	\$36.7	\$380.2	(\$22.6)
				Total	(\$68.9)

Q. Please expand on the recent dynamic where customers have seen a WNA surcharge but the Company is still under recovering its revenue requirement?

A. This is due to a few characteristics regarding the design of the mechanism itself as well as a broader characteristic regarding climate trends. At the core of the WNA is a symmetric mechanism that adjusts utility bills for customers and either credits or charges utility customers based on the difference between actual weather and “normal” weather to arrive at the Commission’s authorized revenue requirement for the Company. In this regard, the WNA, in theory, is completely balanced between the Company and its customers; however, this condition only remains true when the actual weather experienced has an equivalent probability of either being below or

1 above the “normal” weather used to set rates.¹¹ The reality is that given the
2 characteristics of our climate over recent history, there is not an equivalent
3 probability that actual weather will have an equivalent probability of either being
4 above or below “normal” given the current industry practice for the way that normal
5 weather is defined.

6 **Q. Please expand on your last statement.**

7 A. Perhaps the easiest way to demonstrate this concept is visually. In Table 7 below, I
8 have plotted historic average temperatures in Pittsburgh from 1946-2024. Each data
9 point (black circles) represents the average of the daily average temperature for the
10 months November through May (the months active in the WNA) in each calendar
11 year. I also included the trend for this data plotted as a solid black line. The overall
12 trend is warming over time. The ten larger black circles (2015 – 2024) were not
13 included in the determination of the trend; instead, they are used as an empirical
14 comparison to the historic data used to develop the trend, as well as to compare to a
15 simple average of the historic data, which is the most common practice in the
16 industry when defining normal weather. If the simple average of the historic
17 temperatures is considered normal (shown by the red solid line), then one would
18 expect the distribution of future temperatures to center around this average. This is
19 simulated and shown by red diamonds.¹² However, given the warming trend in the
20 historic temperatures, the approach of defining a simple average of historic

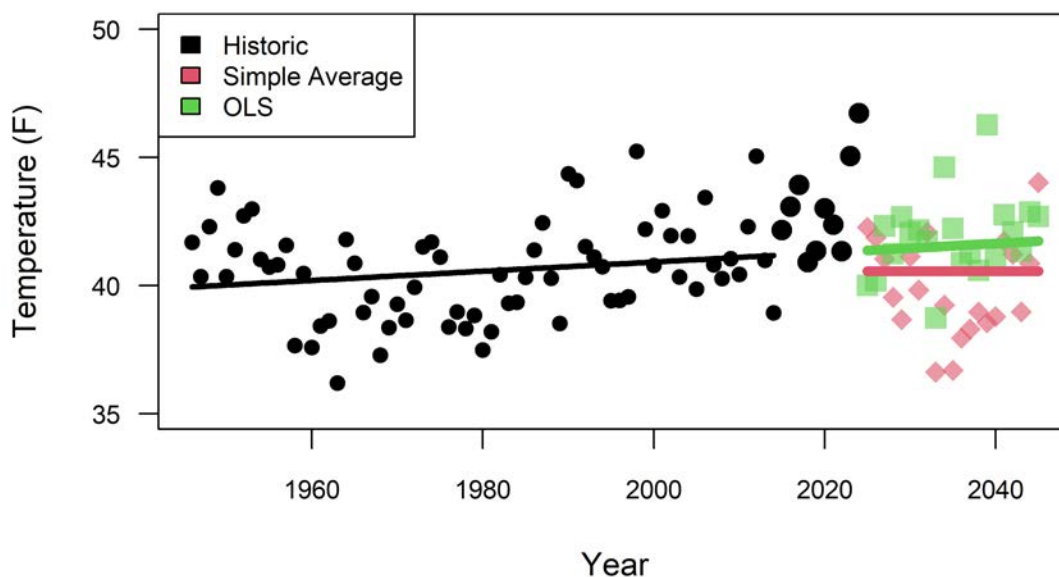
¹¹ When colder than normal weather is experienced, the Company credits customers through the WNA, and when warmer than normal weather is experienced, the Company charges customers through the WNA.

¹² Note the red diamonds do not seem to match well with the historic data (black circles), yet using a simple average as “normal,” one would expect this relationship.

temperatures as normal actually causes a bias and produces an asymmetric result. Also depicted on the figure below, in green squares, are simulated future temperature values centered around the Ordinary Least Squares (“OLS”) trend (extended forward from the historic data also in green). The bias in using a simple average as normal is observed given the large proportion of green squares representing future temperatures centered around the trend, which lie above the simple historic average.

Table 7 – Pittsburgh Temperature Trends

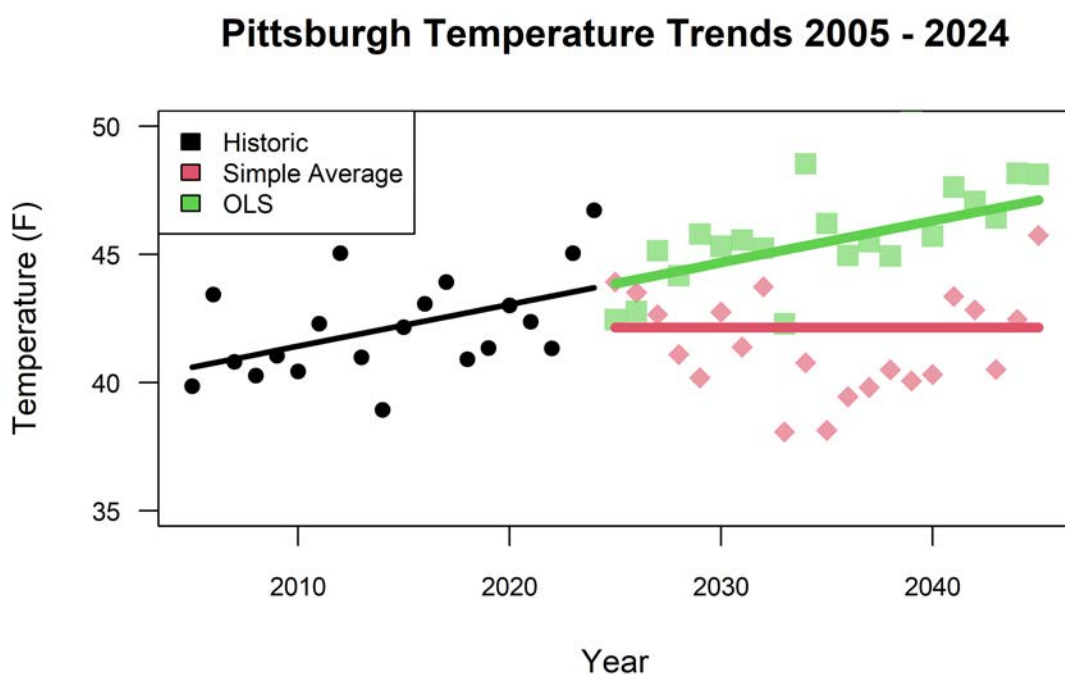
Pittsburgh Temperature Trends 1946 - 2024



Relating this back to the Company’s rates, given the warming trend in the temperatures that is observed, and the way “normal” is defined, the WNA is going to operate in a way where it will, more often than not, be playing “catch up,” adjusting customer bills to offset the difference between warmer actual weather relative to a normal weather that is defined to be colder. This will give the appearance of an asymmetric mechanism, but that is not the case. It is an artifact of the difference

between how normal is defined and the warming trend in actual temperatures. Table 8 below shows the same information as the plot in Table 7 above but limiting the data used to calculate the average and trends to the most recent 20 years of data, which aligns with the current period of time approved by the Commission for the determination of normal weather.

Table 8 – Pittsburgh Temperature Trends (Recent):



Q. You mentioned a few characteristics in the design of the WNA that also lead to an asymmetric result, can you elaborate?

A. The Company's WNA mechanism also contains a deadband as well as it resets the definition of normal each year rather than relating back to the definition of normal used in setting rates. These two characteristics when combined with the general warming trend I discussed above result in a mechanism that will more often than not

1 favor the customer in that the customer will end up paying below the cost of
2 service/revenue requirement approved by the Commission, when the intended
3 purpose of the mechanism is to bring actual revenues recovered by the Company in
4 line with what the Commission has authorized the Company to recover from its
5 customers. This was demonstrated in Table 6 above which demonstrated under
6 recovery for the Company's revenue requirement occurring during periods of a WNA
7 surcharge on customers.

8 **Q. What are potential solutions to this problem?**

9 A. There are three possible solutions. The first is to move to a SFV, cost-based rate
10 design. As I discussed earlier, this aligns with the Company's long-term vision for its
11 rate structure, but the Company is proposing to move towards this vision gradually.
12 Along with movement towards a SFV cost-based rate, another potential solution is a
13 secondary mechanism such as an RNA. I discuss the Company's proposal to
14 implement an RNA in the next section of my testimony. Not only will an RNA help
15 solve the issues I just identified, but it also will provide additional benefits to
16 customers by stabilizing another aspect of the Company's rate structure leading to
17 more predictable bills. Finally, the issues within the WNA itself and how normal is
18 defined could be addressed (for example, one way would be to project trends in the
19 derivation of normal temperatures as a way of removing bias from normal vs
20 observed temperatures); however, the Company is not proposing to address these
21 issues specifically, given the Commission and stakeholders' familiarity with the
22 methods used to forecast normal usage.

1 **V. RNA mechanism proposal**

2 **Q. What is the Company proposal regarding RNA in this proceeding?**

3 A. Columbia proposes the implementation of an RNA mechanism for non-CAP
4 residential and C&I customers that aligns with the Pennsylvania Public Utility
5 Commission's policy considerations under 52 Pa. Code § 69.3302.

6 **Q. Please explain the proposal.**

7 A. The Company's proposed RNA mechanism establishes a benchmark revenue per
8 customer based on the annual authorized revenue requirement approved by the
9 Commission and adjusts future customer bills to recover shortfalls or refund excess
10 revenues compared to the benchmark. The proposed RNA excludes weather related
11 factors that have been previously adjusted through the WNA for the residential class,
12 as those are accounted for in the WNA mechanism. The proposed RNA will be
13 determined and adjusted on an annual basis to ensure the Company accurately
14 recovers its approved revenue target without exceeding or falling short. It is designed
15 as a fully reconciling mechanism, meaning any over- or under-recoveries will be
16 accounted for and incorporated into the next RNA adjustment period.

17 **Q. Please explain how the mechanism would work?**

18 A. The Benchmark Base Revenue Per Customer ("BRPC") will consist of the
19 Commission authorized revenues for the Fully Projected Future Test Year ("FPFTY")
20 divided by the number of customers¹³ determined in the instant rate case for each of

¹³ Equivalent number of bills

the following rate schedules¹⁴:

- Rate Schedule RSS - Residential Sales Service – non-CAP customers only
- Rate Schedule SGSS - Small General Sales Service
- Rate Schedule LGSS - Large General Sales Service
- Rate Schedule RDS - Residential Distribution Service (Choice)
- Rate Schedule SCD - Small Commercial Distribution (Choice)
- Rate Schedule SGDS - Small General Distribution Service
- Rate Schedule SDS - Small Distribution Service
- Rate Schedule LDS - Large Distribution Service

At the end of each calendar year, the Company will file a reconciliation comparing the BRPC with the Actual Base Revenues Per Customer (“ARPC”), inclusive of WNA charges and credits for the residential class and calculate the over or under-collection that resulted for each. In the case of an over-collection, this amount will be credited to the customers in those rate schedules through an RNA surcredit. Alternatively, a surcharge will be assessed in the case of an under-collection. The RNA rate would be calculated following the end of the calendar year and billed over a 12-month period, beginning in April of the same year the calculation is performed. Any over or under recoveries from the prior RNA period would be rolled into the next RNA period. The aim is to collect the exact amount of revenues per customer allowed in base rates.

¹⁴ Rate Schedule NSS - Negotiated Sales Service and Rate Schedule MLDS - Main Line Distribution Service would be excluded from the RNA calculations

Mechanically, the RNA Adjustment is determined through the following series of calculations:

1. BRPC = Authorized Base Revenue for the FPFTY per Rate Schedule ÷ Projected Number of Bills per Rate Schedule × 12 months.
2. ARPC = (Actual Base Revenue + WNA¹⁵) for the FPFTY per Rate Schedule ÷ Actual Number of Bills per Rate Schedule × 12 months.
3. Total Over or Under Collection for Year per Rate Schedule = BRPC – ABRC
4. Current Year RNA Adjustment = Total Over or Under Collection per Rate Schedule.
5. Total RNA Adjustment = (Current Year RNA Adjustment + Annual True-Up¹⁶) ÷ 12 Months.
6. Annual True-Up = Difference between Projected RNA Collection and Actual RNA Collection for Past 12 Months.

Q. Does Columbia propose to apply interest to the RNA balances?

A. Yes. Refunds to customers shall be made with interest and recoveries from customers shall include interest at the rate of 6% annually.

Q. Has the Company prepared the corresponding tariff sheets?

A. Yes. Company witness Ribeka Danhires sponsors the RNA tariff sheets.

Q. How is the RNA mechanism different from the WNA?

¹⁵ For the Residential Class

¹⁶ Annual True-Up applies after the first year

1 A. The WNA mechanism only accounts for the changes in heating load sales that occur
2 due to the difference between actual weather and normal weather. The RNA is a
3 decoupling mechanism that separates a utility's distribution revenues from its level
4 of sales, thereby "breaking the link" so that the utility may recover an established
5 amount of revenues, even as sales fluctuate. Therefore, while the WNA provides a
6 level of revenue stability related to weather changes for the residential class, it does
7 not completely decouple revenues from all sales-related variances as a full revenue
8 decoupling would provide.

9 **Q. Why is this RNA mechanism needed in addition to the WNA?**

10 A. The RNA and WNA serve distinct purposes, and the RNA is necessary to ensure full
11 revenue stabilization that the WNA alone cannot achieve. The WNA adjusts customer
12 bills to account for abnormal weather conditions during the months of November
13 through May, ensuring that most revenue fluctuations caused by warmer- or colder-
14 than-normal temperatures during that period are neutralized (within the deadband).
15 While the WNA corrects for short-term weather-driven deviations, the RNA
16 addresses non-weather-related revenue fluctuations, along with weather-related
17 revenue fluctuations not captured by the WNA (i.e., shoulder month heating loads
18 sensitive to weather and the non-application of the WNA due to the deadband) and
19 it ensures that Columbia recovers its approved revenue requirement even when long-
20 term usage patterns change while ensuring customers do not pay more than their
21 cost to serve.

22 **Q. Please provide an example of how the RNA would be calculated.**

1 A. The following shows the process steps with an example for illustrative purposes:

- 2 • Establish Benchmark Revenue per Customer: Assume the Commission approves a
3 total residential distribution revenue requirement of \$400 million, with an
4 estimated 400,000 residential customers.¹⁷ The target revenue per customer
5 would be: $\$400,000,000 \div 400,000 = \$1,000$ per customer annually, which
6 would be the baseline for revenue recovery.
- 7 • Apply WNA Throughout the Year: Assume that colder-than-normal weather
8 during the winter increases customer gas usage beyond normal expectations. As a
9 result, Columbia collects more revenue than expected, since higher consumption
10 leads to increased volumetric charges. The WNA applies credits to refund the
11 excess revenue due to weather-related over-collection, ensuring Columbia does not
12 over-recover due to abnormal weather. Assume Columbia collected \$1,050 per
13 customer and \$30 of the excess is due to weather, which is refunded via WNA,
14 adjusting Columbia's post-WNA actual revenue to \$1,020 per customer.
- 15 • Calculate RNA Based on Post-WNA Revenue: Since the RNA is applied after WNA
16 adjustments, Columbia now compares the post-WNA revenue of \$1,020 to the
17 approved benchmark of \$1,000. The RNA ensures Columbia does not over-recover
18 revenues, so an additional \$20 per-customer refund is calculated.
- 19 • Apply RNA: The RNA now credits customers to return the remaining excess
20 revenue of \$20 per customer spread over the following year.

¹⁷ As noted earlier in my testimony on Pages 43 & 44, this excludes CAP customers.

1 **Q. Please describe the relevant factors for the Commission to determine**
2 **that the Company's RNA proposal is just and reasonable.**

3 A. Each policy factor relevant to the Commission's evaluation is discussed below, along
4 with the specific impact of Columbia's RNA proposal on each consideration. The
5 following fourteen items align with the considerations identified within the
6 Statements of Policy as outlined by the Commission in the alternative rate making
7 Docket No. M-2015-2518883.

8 1. **Alignment with Cost Causation Principles:** The RNA ensures that Columbia
9 recovers its authorized revenue requirement, and customers do not pay more than
10 their cost to serve. The mechanism is designed to recover fixed distribution costs,
11 which do not vary with gas consumption. Since these costs are incurred regardless
12 of individual usage, the RNA ensures that revenue collection is aligned with the
13 cost-of-service established in this proceeding while preventing both over-
14 collection and revenue shortfalls. In the absence of SFV rate design, where all fixed
15 costs are recovered in a fixed monthly charge, an RNA mechanism will better align
16 distribution revenues with cost causation principles.

17 2. **Impact on Fixed Utility's Capacity Utilization:** The RNA mechanism
18 supports efficient capacity utilization by stabilizing the recovery of fixed
19 distribution costs, which are incurred to maintain Columbia's infrastructure and
20 capacity to serve customers regardless of fluctuations in gas usage. Since these
21 fixed costs do not change with short-term usage variations, the RNA ensures that
22 Columbia can continue investing in the infrastructure necessary to meet peak

1 demand and long-term capacity needs and be compensated for these investments.
2 By maintaining revenue stability, the RNA reduces under-recovery risks during
3 periods of lower gas usage, ensuring that the revenues collected align with use of
4 the utility's fixed assets by customers.

5 **3. Reflection of Demand Associated with the Customer's Anticipated**

6 **Consumption:** The RNA is structured to adjust for non-weather-related
7 variations in customer usage while maintaining a revenue level that reflects the
8 anticipated demand established in the FPFTY. In the absence of SFV rate design,
9 the RNA results in revenue recovery aligned with the demand associated with
10 customer's anticipated consumption.

11 **4. Limiting Inter-Class and Intra-Class Cost Shifting:** With regard to inter-

12 class cost shifting, the RNA targets are calculated within each class, ensuring that
13 no costs are shifted to other customer classes. Additionally, within each class,
14 adjustments are made on a per-customer basis, meaning that each customer is
15 responsible for their share of revenue normalization adjustments. This prevents
16 intra-class cross-subsidization between high-usage and low-usage customers while
17 ensuring fair cost allocation within the class.

18 **5. Eliminates Disincentive for Promotion of Energy Efficiency and**

19 **Conservation Programs:** The RNA breaks the link between utility revenues and
20 sales volumes, removing the financial disincentive for Columbia to promote energy
21 efficiency. Since revenue recovery is based on a pre-approved benchmark resulting
22 from this rate case, Columbia can continue investing in demand-side management

1 programs, energy efficiency rebates, and customer conservation initiatives without
2 revenue loss concerns.

3 **6. Customer Incentives for Efficiency and Distributed Energy Resources:**

4 Customers will still see savings from reducing usage, as commodity charges, taxes,
5 and a portion of distribution charges remain volumetric. The RNA only adjusts
6 base distribution revenues, preserving incentives for conservation. Further, given
7 the Company is not proposing SFV rate design, each customer's distribution bill
8 will be comprised of a volumetric charge such that the total distribution bill and
9 any WNA or RNA adjustments will be lower if a customer implements energy
10 efficiency measures.

11 **7. Impact on Low-Income Customers:** The RNA excludes CAP customers.

12 Moreover, by ensuring stable revenues, the RNA supports the continued funding
13 of low-income assistance programs and infrastructure investments that benefit all
14 customers.

15 **8. Rate Stability:** The RNA mitigates revenue volatility caused by fluctuating usage

16 patterns. In addition, any RNA over-recovery or under-recovery will be adjusted
17 over the next twelve months, resulting in a more stable surcharge or credit.
18 Customers benefit from more predictable distribution charges over time.

19 **9. Interaction with Weather:** The RNA is separate from Columbia's WNA

20 mechanism. The WNA addresses short-term fluctuations in revenue due to
21 weather variations, while the RNA focuses on non-weather-related factors, such as
22 conservation, economic trends, and customer growth/loss, as well as weather

1 related factors not captured by the WNA (e.g., shoulder months and the non-
2 application of WNA due to the deadband).

3 **10. Impacts on the Frequency of Rate Case Filings and Regulatory Lag:** The
4 proposed RNA is designed to ensure that the Company neither over- nor under-
5 collects the approved revenue target. This will allow the Company to cover the
6 investments and expenses projected in the FPFTY. Future rate cases will still be
7 necessary to address changes to the cost of service.

8 **11. Interaction with Other Revenue Sources:** Columbia's proposed RNA is
9 solely focused on recovering costs that are part of the base revenue requirement
10 and does not interact with other revenue sources, such as Section 1307 automatic
11 adjustment surcharges, restructuring riders, or system improvement charges
12 under Section 1353.

13 **12. Consumer Protections:** Columbia's proposed RNA includes several consumer
14 protections to ensure fairness and transparency, as follows:

15 a. **No Over-Recovery of Revenue:** The RNA is designed to prevent Columbia
16 from over-recovering revenues, as it only allows adjustments to align actual
17 revenues with the Commission-approved base revenue requirement. If
18 revenues exceed the benchmark, customers receive refunds or credits,
19 ensuring that Columbia does not collect more than authorized.

20 b. **No Cross-Subsidization:** The RNA applies within each customer class and
21 on a per-customer basis, meaning that no costs are shifted between different
22 customer classes or disproportionately distributed among customers.

1 c. Regulatory Oversight: The RNA is subject to Commission review and
2 regulatory reporting requirements to ensure compliance with approved
3 revenue stabilization objectives and protect consumers from unintended
4 rate impacts.

5 d. Customer Transparency: Columbia will provide clear bill disclosures and
6 customer education regarding RNA adjustments, ensuring consumers
7 understand how the mechanism works and how it impacts their bills.

8 **13. Complexity and Customer Understanding:** Columbia Gas will implement
9 clear customer communications, including bill inserts, an online education portal,
10 and trained customer service representatives to address customer questions.
11 Additionally, the RNA adjustments will be displayed separately on bills, ensuring
12 full transparency.

13 **14. Utility Reliability Improvement Support:** The RNA supports the Company's
14 reliability improvements by ensuring stable and predictable cost recovery, which
15 is essential for maintaining and upgrading Columbia's distribution system. Since
16 Columbia's infrastructure investments—such as pipeline replacements, leak
17 detection programs, and safety upgrades—are fixed costs that do not vary with
18 customer usage, the RNA helps secure the necessary funding to sustain these
19 reliability-driven initiatives.

20 **Q. Are RNA mechanisms like the one proposed in this filing common**
21 **among natural gas utilities?**

1 A. Yes, RNA mechanisms, which decouple or disassociate a utility's total distribution
2 revenues from the sale of commodity through regulatory formulas, are a common
3 ratemaking tool throughout the natural gas industry. Atrium Economics performed
4 a survey nationwide and found at least 50 natural gas utilities in 21 different states
5 with full or partial approved decoupling mechanisms, many of them similar to the
6 one proposed by Columbia.

7 **Q. Please summarize your recommendations.**

8 A. I recommend that the Commission approve the following:

- 9 1. Columbia's rate design proposal, which more accurately aligns with cost
10 causation since most distribution costs are fixed and do not significantly
11 fluctuate based on gas usage.
- 12 2. The proposed residential customer charge of \$31.97, which conveys more
13 appropriate price signals with respect to recovery of fixed distribution costs,
14 would help reduce customer bill volatility, would benefit low-income
15 customers that have higher than average use, and is not regressive in
16 application to low-income customers who may have little control over their
17 use of energy by recovering more in volumetric charge.
- 18 3. Conversion of the WNA pilot program to a permanent program, which
19 addresses weather-driven revenue fluctuations, to the extent that there is a
20 portion of distribution fixed costs being recovered through a volumetric
21 charge.

1 4. Columbia's RNA proposal, which aligns with Pennsylvania's alternative
2 ratemaking policy goals by promoting revenue stability, fair cost allocation,
3 and energy efficiency while avoiding unnecessary rate volatility.

4 **Q. Does this complete your Direct Testimony?**

5 A. Yes, it does.

John D. Taylor

MANAGING PARTNER

Mr. Taylor has experience with a wide range of costing, ratemaking, and regulatory activities for gas and electric utilities. He has testified numerous times on these and other issues for clients across North America. He has extensive experience with costing and pricing rates and services, regulatory planning and strategy development, revenue recovery and tracking mechanisms, merger and acquisitions analysis, new product and service development, affiliate transaction reviews, line extension policies, market assessments, litigation support, and organizational and operations reviews. He has testified on numerous occasions as an expert witness on costing and ratemaking related issues on behalf of utilities before federal, state, and provincial regulatory bodies and has extensive experience in evaluating and implementing innovative ratemaking approaches and rate design concepts.

He has also testified on return on equity, electric vehicle and battery storage programs, time-of-use rates, and the appropriate use of statistical analysis during audit testing. Mr. Taylor has led engagements relating to gas supply planning and the review of midstream transportation and storage capacity resources. He has worked as the market monitor for New England ISO's capacity market, supported the negotiation of PPAs, and supported feasibility and prudence studies of generation investments. He has also been involved in selling generating assets and distribution companies, supporting due diligence efforts, financial analyses, and regulatory approval processes.

Mr. Taylor received a master's degree in Economics from American University and holds a bachelor's degree in Environmental Economics from the University of North Carolina at Asheville.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

18

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



His consulting career includes Managing Partner with Atrium Economics, LLC; Principal Consultant – Advisory & Planning with Black & Veatch Management Consulting, LLC; Senior Project Manager & Principal of Concentric Energy Advisors, Inc.; and CEO of Nova Data Testing, Inc. Mr. Taylor started his career working on Capitol Hill working with NGOs that were seeking Public Private Partnerships with the Federal Government, World Bank, and International Monetary Fund to pursue various projects in developing countries.

EXPERT WITNESS TESTIMONY PRESENTATION

UNITED STATES:

- California Superior Court of California
- Delaware Public Service Commission
- Florida 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
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Ohio Public Utility Commission
- Pennsylvania Public Utility Commission
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission

CANADA:

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board
- Public Service Commission of West Virginia

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 development 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 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
PENNSYLVANIA PUBLIC UTILITY COMMISSION**

Pennsylvania Public Utility	)	
Commission	)	
	)	
v.	)	Docket No. R-2025-3053499
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
JASON LEAL
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 20,2025

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Jason Leal. My business address is 801 E. 86th Avenue, Merrillville, IN 46410.

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

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource") as Manager Financial Planning & Analysis ("FP&A").

Q. What are your responsibilities as Manager Financial Planning Analysis?

A. I am responsible for analysis and support in the Operations and Maintenance ("O&M") expense budgeting process for NiSource's gas distribution companies, including Columbia Gas of Pennsylvania, Inc. ("Columbia"), Columbia Gas of Maryland, Inc, and Columbia Gas of Virginia, Inc. My role also involves coordinating with the broader financial planning and budgeting processes within NCSC.

Q. What is your educational and professional background?

A. I hold a Bachelor of Science degree in Business Administration with a major in Accounting from Purdue University, which I earned in 2008. In 2021, I obtained a Master of Business Administration degree from the University of Southern Indiana. I have over 16 years of experience in FP&A and regulatory support roles, primarily supporting NiSource subsidiaries such as Columbia Gas of Pennsylvania, Inc. I began my career at Northern Indiana Public Service Company LLC ("NIPSCO") in

1 January 2009 as a Financial Analyst in the Rates and Regulatory department, where
2 I supported NIPSCO's Electric Fuel Cost Adjustment and Gas Fuel Cost Adjustment
3 filings. In July 2010, I was promoted to Senior Regulatory Analyst, where I deepened
4 my regulatory expertise. In July 2013, I transitioned to the FP&A department as a
5 Senior Financial Analyst, focusing on budgeting and variance analysis of various
6 components of NIPSCO's Income Statement. In November 2017, I was promoted to
7 Lead Financial Analyst, expanding my responsibilities in FP&A. In October 2018, I
8 accepted a position as Lead Regulatory Analyst in the Regulatory Strategy and
9 Support department. In that role, I provided regulatory support for several key cost
10 recovery mechanisms, including NIPSCO's Environmental Cost Recovery
11 Mechanism, Environmental Expense Recovery Mechanism, and Federally Mandated
12 Cost Adjustment ("FMCA") tracker filings. Additionally, I supported regulatory
13 filings for Columbia Gas of Maryland, Inc. In March 2021, I transitioned to the NCSC
14 FP&A department as a Lead Financial Analyst. My responsibilities included
15 budgeting and variance analysis for the direct O&M expenses of Columbia Gas of
16 Pennsylvania, Inc. In March 2025, I assumed my current position of Manager FP&A
17 for Columbia Gas of Pennsylvania, Inc, Columbia Gas of Maryland, Inc, and
18 Columbia Gas of Virginia, Inc.

19 **Q. Have you previously testified before this Commission or any other**
20 **Commission?**

21 A. Yes. I presented direct testimony for NIPSCO before the Indiana Utility Regulatory

Commission in Cause No. 44340-FMCA-13. In that proceeding, I supported NIPSCO's proposed ratemaking treatment for FMCA factors to facilitate the timely recovery of federally mandated costs associated with compliance projects. Additionally, I submitted rebuttal testimony in Columbia Gas of Pennsylvania's 2024 Rate Case, Docket No. R-2024-3046519.

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

A. The purpose of my testimony is to outline the budgeting process for Columbia's Gas Utility Segment departments, which include Field Operations, Customer Programs, and Presidents, and to explain how the Company's budget is determined. My testimony supports the projected O&M expenses for the Fully Projected Future Test Year ("FPFTY") ending December 31, 2026. These expenses are incorporated into the cost-of-service analysis presented by Columbia witness Joseph Vassalotti in Columbia Statement No. 4. Company witness George Jonda will address corporate O&M functions, overhead expenses, and NCSC budgeting processes in Columbia Statement No. 15.

II. FULLY PROJECTED FUTURE TEST YEAR – O&M EXPENSE

Q. What is the basis for the forecasted O&M expense included in the Fully Projected Future Test Year?

A. The forecasted O&M expense for the FPFTY is derived from the Company's most recent O&M budget.

Q. How is the O&M budget developed?

A. The O&M budget for Columbia is developed collaboratively by three groups within the organization.

(1) Operations Planning: This group develops the Field Operations budget at the cost element level. The budget incorporates expected cost increases, such as merit and supplier increases, as well as savings from continuous improvement initiatives. The budget is compared to prior year spending to ensure it is reasonable and aligns with current expectations.

(2) State Financial Planning and Analysis (State FP&A): State FP&A reviews the Field Operations budget to ensure it is accurately entered into the system, develops the O&M budget for the Gas Utility Segment departments, and verifies that the budget is appropriately allocated by department, cost element, and month. The budgeting process described above is for all expenses charged directly to each subsidiary.

(3) Corporate Financial Planning & Analysis (Corporate FP&A): Corporate FP&A budgets the Company's NCSC allocations, corporate O&M functions, and overhead expenses charged outside the Gas Utility Segment. Company witness George Jonda addresses these elements in Columbia Statement No. 15.

1 **Q. Does that conclude the development of the O&M expense budgeting**
2 **process?**

3 A. No. The budgeting process includes multiple reviews with business partners and
4 Company Leadership to refine and finalize the budget. The final budget is approved
5 by the Company President and the Senior Vice President of FP&A after comparisons
6 to prior budgets and actual expenses. These steps ensure alignment with company
7 and parent company expectations. Once approved, the O&M expense budget is
8 integrated into the Company's operating plan.

9 **Q. Have you excluded certain cost categories from your comparison?**

10 A. Yes. Certain O&M expenses that track directly with revenues, such as gas costs and
11 low-income programs, are excluded. These expenses are subject to revenue-
12 matching mechanisms approved by the Commission, ensuring no impact on net
13 operating income. These mechanisms allow the deferral and reclassification of such
14 expenses, which are excluded to maintain budget accuracy.

15 **Forecasted Labor Expense**

16 **Q. What are the principal assumptions used in the development of the labor**
17 **cost element for specific department budgets included in the forecasted**
18 **test period O&M expenses?**

19 A. Labor expense for exempt employees (salaried employees not subject to overtime) is
20 determined based on projected headcount and wage increase assumptions for the
21 FTY and FPFTY. The forecasting process for labor costs in Gas Utility Segment

1 departments (excluding Field Operations) begins with the current organizational
2 chart. Anticipated changes such as new hires, promotions, transfers, and
3 terminations are incorporated with input from department leaders to ensure
4 accuracy. The labor planning module applies an annual merit increase of 3% across
5 the salaried workforce. This adjustment accounts for salary changes driven by
6 performance, inflation, or market conditions, and aligns with the company's overall
7 compensation strategy or any specific budget guidelines for the year. Additionally,
8 the planning system applies a capitalization rate, which reduces labor expense to
9 reflect capitalized labor costs associated with capital projects. The projected labor
10 expense by department is then compared to the prior year's values for reasonableness
11 and accuracy before finalizing the plan.

12 Labor expense in the field operations department is driven by projected work
13 activity and staffing needs aligned with operational plans. The process begins with a
14 detailed forecast of expected work by activity type. This forecast is based on historical
15 data, regulatory requirements, planned system upgrades, and anticipated customer
16 demand. Hourly staffing requirements are calculated by estimating the time and
17 labor needed to complete each activity type. The department evaluates the number
18 of hours required per job or task, factoring in productivity rates and anticipated
19 overtime. Overtime assumptions are included based on historical trends and
20 projected workload peaks. For activities related to capital projects, a portion of the
21 hourly labor costs is capitalized to reflect the allocation of labor to capital investments

rather than operating expenses. The total projected labor costs are reviewed and compared to prior-year expenses for reasonableness and accuracy. Adjustments may be made to account for efficiency improvements, changes in workload, or other operational considerations before finalizing the budget.

Q. Does your budgeting analysis include any projections regarding Columbia headcount?

A. Yes. Columbia projects 715 active full-time employees for 2025 and 2026. Wage increases of 3% are assumed for exempt and non-exempt employees for both years, with labor costs for bargaining unit employees based on existing contracts.

Forecasted Non-Labor Expenses

Q. Please explain how non-labor activities or events are taken into account in the development of the O&M expense budget.

A. Non-labor expenses are budgeted at the cost element level, aligning with historical spending patterns, known assumptions, and operational needs, with adjustments made for incremental activities or non-recurring expenses as necessary.

O&M Expense Levels

Q. What are the O&M expense levels for the Historic Test Year, Future Test Year, and Fully Projected Future Test Year?

A. Per Exhibit 104, Schedule 1, Pages 3 and 4, Row 21, O&M expenses are as follows:

- \$179,631,010 for the Normalized Historic Test Year ending November 30, 2024
- \$180,042,501 for the Budgeted Future Test Year ending November 30, 2025

1 • \$175,019,558 for the Budgeted Fully Projected Future Test Year ending December
2 31, 2026

3 These represent an increase of \$411,491 and a decrease of \$5,022,943, respectively,
4 before pro forma ratemaking adjustments.

5 **Q. Does this complete your direct testimony?**

6 A. Yes, it does.