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BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION

Peoples Natural Gas Company LLC

Docket No. R-2026-3060855

Volume IX

Direct Testimony and Exhibits of:
Jennifer Nelson, Statement No. 15
John P. Spanos, Statement No. 16
John Taylor, Statement No. 17

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2026-3060855
PEOPLES NATURAL GAS COMPANY LLC	:	

PREPARED DIRECT TESTIMONY OF
JENNIFER E. NELSON
CONCENTRIC ENERGY ADVISORS
ON BEHALF OF
PEOPLES NATURAL GAS COMPANY LLC

DATE SERVED: March 27, 2026 Peoples Statement No. 15

DATE ADMITTED: _____

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PREPARED DIRECT TESTIMONY
OF JENNIFER E. NELSON

I. WITNESS IDENTIFICATION AND BACKGROUND

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

A. My name is Jennifer E. Nelson. I am a Vice President at Concentric Energy Advisors. Concentric is a management consulting and economic advisory firm that specializes in the North American energy and water industries. Based in Marlborough, Massachusetts; Washington, D.C.; and Calgary, Alberta; Concentric specializes in regulatory and litigation support, financial advisory services, energy market strategies, market assessments, energy commodity contracting and procurement, economic feasibility studies, and capital market analyses. My business address is 293 Boston Post Road West, Suite 500, Marlborough, Massachusetts, 01752.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND PROFESSIONAL EXPERIENCE.

A. I hold a Bachelor's degree in Business Economics from Bentley University and a Master's degree in Resource and Applied Economics from the University of Alaska. I have more than fifteen years of experience in the energy industry, having served as a consultant and energy/regulatory economist for state government agencies. Since 2013, I have provided consulting services to clients on a range of financial and regulatory issues including cost of capital, ratemaking policy, and regulatory and financial strategy issues. Prior to consulting, I was a staff economist at the Massachusetts Department of Public Utilities, and a petroleum economist for the State of Alaska. I completed utility regulatory training offered by New Mexico State University's Center for Public Utilities and have earned the Certified Rate of Return Analyst designation from the Society of Utility and Regulatory Financial Analysts

based on my experience and successful completion of an examination. A summary of my professional and educational background, including a list of my testimonies filed before regulatory commissions, is included as Exhibit JEN-1.

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

A. I am testifying on behalf of Peoples Natural Gas Company LLC ("Peoples" or the "Company"). Peoples is a wholly-owned subsidiary of PNG Companies, LLC, which is ultimately owned by Essential Utilities, Inc., ("Essential").

Q. HAVE YOU PREVIOUSLY SUBMITTED TESTIMONY BEFORE THE PENNSYLVANIA PUBLIC UTILITY COMMISSION ("PAPUC" OR THE "COMMISSION")?

A. Yes, I filed testimony before the Commission on behalf of PPL Electric Utilities Corporation in Docket No. R-2025-3057164 regarding the cost of capital. Additionally, I have filed testimony before more than 20 state regulatory commissions as detailed in Exhibit JEN-1. During my time as a consultant, I have supported the development of expert witness testimony and analyses regarding the cost of capital (*i.e.*, Return on Equity ("ROE") and capital structure) in more than 100 proceedings filed before numerous U.S. state regulatory commissions and the Federal Energy Regulatory Commission.

II. PURPOSE AND OVERVIEW OF TESTIMONY

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

A. The purpose of my direct testimony is to present evidence and provide a recommendation regarding the Company's return on equity. I also present and support the Company's proposed long-term capital structure and cost of long-term debt.

Q. ARE YOU SPONSORING ANY EXHIBITS IN THIS CASE?

A. Yes. My analyses and recommendations are supported by the data presented in Exhibit JEN-2 through Exhibit JEN-13, which have been prepared by me or under my direction. I sponsor the following exhibits:

Exhibit JEN-1	Résumé and Testimony Listing of Jennifer E. Nelson
Exhibit JEN-2	Constant Growth DCF Results
Exhibit JEN-3	Quarterly Growth DCF Results
Exhibit JEN-4	Market Return Calculations
Exhibit JEN-5	CAPM and Empirical CAPM Results
Exhibit JEN-6	Bond Yield Plus Risk Premium Analysis
Exhibit JEN-7	Capital Expenditure Analysis
Exhibit JEN-8	Regulatory Risk
Exhibit JEN-9	Flotation Costs
Exhibit JEN-10	Capital Structure for Peoples Natural Gas
Exhibit JEN-11	Proxy Group Capital Structure Analysis
Exhibit JEN-12	Proxy Group Authorized Equity Ratios
Exhibit JEN-13	Cost of Long-Term Debt

Additionally, the list of the Standard Filing Requirement schedules that I sponsor is provided in Appendix A to my testimony.

Q. WERE THESE EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. PLEASE SUMMARIZE YOUR RECOMMENDATION REGARDING THE APPROPRIATE COST OF EQUITY FOR PEOPLES.

A. In this proceeding, I recommend the Commission authorize a base ROE of 11.00 percent for Peoples. To develop my ROE recommendation, I rely on the results of three widely used market-based financial models: (1) the constant growth and quarterly growth forms of the Discounted Cash Flow ("DCF") model, (2) the traditional and empirical forms of the Capital Asset Pricing Model ("CAPM"), and (3) the Bond Yield Plus Risk Premium. As shown in Figure 1 below, these models indicate a base cost of equity ranging from approximately 10.20 percent to 11.90 percent. The approximate average of the three models and midpoint of the range is 11.00 percent. Further, I do not make an additional adjustment for Peoples' planned capital expenditures, customer concentration and bypass risk, or flotation costs. Therefore, I conclude that a base ROE of 11.00 percent is a reasonable estimate of Peoples' cost of equity.

Figure 1: Summary of Results[1]

Model	**ROE Estimate**
Constant Growth DCF	10.79%
Quarterly Growth DCF	11.03%
Average DCF	**10.91%**
Forward CAPM	13.09%
Forward ECAPM	13.91%
Historical CAPM	10.11%
Historical ECAPM	10.64%
Average CAPM	**11.94%**
Risk Premium	10.24%
3-Model Average	**11.03%**

[1] *See*, Exhibit JEN-2 to Exhibit JEN-6. DCF and CAPM results reflect the average of the proxy group mean and median ROE estimates. Data as of January 30, 2026.

Model	ROE Estimate
Range of Model Results (Rounded)	10.20%-11.90%
Base ROE Recommendation	**11.00%**
Management Adder	0.25%
Final ROE Request	**11.25%**

As explained in **Peoples Statement No. 1 – the Direct Testimony of Michael Huwar**, Peoples is requesting a 25 basis point performance adder to reflect its superior management performance.[2] As stated in Witness Huwar's Direct Testimony, Peoples' strong management performance—evidenced by improved customer service, accelerated infrastructure investment, and its economic and civic contributions—supports a modest management adder. A 25 basis point increase to my recommended return of 11.00 percent within the range of model results and helps ensure continued access to capital for critical infrastructure investment in Pennsylvania.

As to the Company's capital structure, the requested permanent capital structure consisting of 54.47 percent common equity and 45.43 percent long-term debt reflects its Fully Projected Future Test Year ("FPFTY") capital structure and is within the range of the proxy group. It is also consistent with the actual and authorized capital structures of the gas utility peers.[3] Accordingly, the Company's requested capital structure is reasonable and should be approved. The Company's requested FPFTY Weighted Average Cost of Capital ("WACC") is shown in Figure 2 below.

[2] Direct Testimony of Michael Huwar, at 30.
[3] *See,* Exhibit JEN-11 and Exhibit JEN-12.

Figure 2: FPFTY Weighted Average Cost of Capital[4]

	% of Capital	Cost (%)	Weighted Cost
Long-Term Debt	45.53%	4.61%	2.10%
Common Equity	54.47%	11.25%	6.13%
Total	100.00%		8.23%

Q. WHAT FACTORS DO YOU CONSIDER IN DETERMINING YOUR ROE RECOMMENDATION?

A. The cost of equity is an opportunity cost that cannot be precisely quantified. Therefore, it must be estimated using various financial models. Each of the ROE estimation models is subject to limiting assumptions and each provides a different perspective on investors' return requirements under varying market conditions. The use of multiple financial models, therefore, enables a robust and comprehensive assessment of the cost of equity instead of relying on one specific estimation model.

In addition to the analytical results summarized above, my recommendation considers: (1) the Company's significant capital investment needs; (2) the regulatory environment in which the Company operates; (3) the risk associated with the ability of large customers to bypass Peoples' system; (4) the cost of issuing common equity (or flotation costs); (5) Peoples' financial risk reflected in its capital structure; and (6) the current capital market environment. Although those factors are relevant to investors, their effect on the Company's cost of equity cannot be directly quantified. While I do not make any explicit adjustments to my ROE estimates for Peoples' business risks, I consider them when determining my ROE recommendation.

[4] *See,* Exhibit JEN-10 and Exhibit JEN-13.

Based on those considerations, it is my opinion that a base ROE of 11.00 percent, before an adjustment for the Company's management performance, is a reasonable, if not conservative estimate of Peoples' cost of equity.

Q. IS YOUR BASE ROE RECOMMENDATION SUPPORTED BY DATA REPORTED IN THE COMMISSION'S BUREAU OF TECHNICAL UTILITY SERVICES QUARTERLY EARNINGS REPORTS?

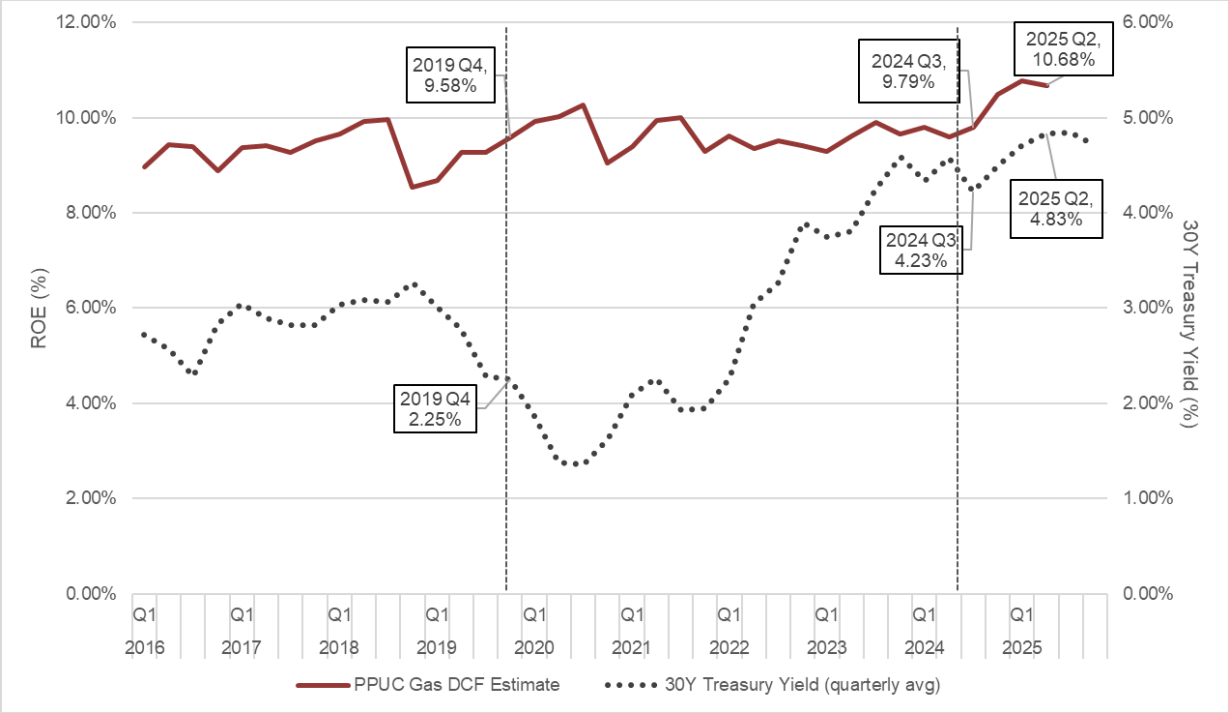
A. Yes. In its most recent *Bureau Of Technical Utility Services Report On The Quarterly Earnings Of Jurisdictional Utilities for the Year Ended June 30, 2025*, the Current Market Indicated ROE for the gas utilities ranged from 9.33 percent to 12.02 percent.[5] My base ROE recommendation of 11.00 percent is within this range.

Additionally, the quarterly DCF results for the gas barometer group reported in the quarterly earnings reports have been increasing (*see*, Figure 3 below). Figure 3 graphs the PPUC's published gas barometer group DCF results for the past ten years, as well as the 30-year Treasury yield over the same period. As shown in Figure 3, the 30-year Treasury yield has increased considerably since Peoples' last two rate cases, and the DCF results reflected in the Commission-developed have increased correspondingly. For example, the Commission issued its Order in Peoples' 2019 rate case on October 3, 2019 when the 30-year Treasury yield was 2.25 percent and the Q4 2019 Commission-developed DCF analysis for the natural gas barometer group was 9.58 percent. The Company's most recent rate case concluded on September 12, 2024, when the 30-year Treasury yield escalated nearly 200 basis points to 4.23 percent. The Commission's gas group DCF analysis increased 20 basis points to 9.79 percent.

[5] Bureau Of Technical Utility Services Report On The Quarterly Earnings Of Jurisdictional Utilities for the Year Ended June 30, 2025, at 14, https://www.puc.pa.gov/filing-resources/reports/quarterly-earnings-summary-reports/

As of June 30, 2025, the most recently published PPUC earnings report calculated a gas group DCF estimate nearly than 90 basis points higher, or 10.68 percent, compared to the 30-year Treasury yield of 4.83 percent. This data demonstrates that the cost of equity for the natural gas utilities as estimated by the Commission's DCF analysis has increased since the Company's last two rate cases.

Figure 3: Historical PAPUC Gas



DCF Estimate and 30-Year Treasury Yield[6]

Q. DOES YOUR RECOMMENDATION CONSIDER THE CURRENT AND EXPECTED INTEREST RATE ENVIRONMENT?

A. Yes, it does. As shown in Figure 3 above, the 30-year Treasury bond yield has risen over 200 basis points over the course of the Company's last two rate cases. As discussed in more detail

[6] Sources: https://www.puc.pa.gov/filing-resources/reports/quarterly-earnings-summary-reports/; Federal Reserve Bank of St. Louis, FRED Economic Database.

in Section VI, although the Federal Reserve reduced the Federal Funds rate by 75 basis points in 2025, long-term government and utility bond yields have not followed suit and are expected to remain near current levels over the next five years.

Q. HAS THE COMMISSION PREVIOUSLY ACKNOWLEDGED THE IMPORTANCE OF CONSIDERING PREVAILING MARKET CONDITIONS IN DETERMINING THE APPROPRIATE ROE?

A. Yes, in its July 2024 Opinion and Order for Pennsylvania American Water Company in Docket No. R-2023-3043189, the Commission considered the prevailing market conditions of increasing inflation, higher interest rates, and capital costs in approving an ROE that reflected the average of the DCF and CAPM results.[7] As explained later in my Direct Testimony, these conditions persist, and are expected to persist, going forward.

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

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

- Section III – Summarizes the regulatory guidelines relevant to the cost of capital estimation in regulatory proceedings, explains my selection of the proxy group used to develop my analytical results, and describes the analyses on which my ROE determination is based;
- Section IV – Discusses the effect of the Company's business risks, including its planned capital expenditures, the ability of large customers to bypass Peoples' system, its regulatory environment, and flotation costs on its cost of equity;

[7] Pennsylvania American Water Company, Docket No. R-2023-3043189, Opinion and Order, at 194 (July 11, 2024).

- Section V – Provides an assessment of the Company's requested capital structure and cost of long-term debt; and
- Section VI – Reviews the current capital market conditions and the implication on the cost of equity; and
- Section VII – Summarizes my conclusions and recommendations.

III. COST OF EQUITY ESTIMATION

A. Regulatory Guidelines and Financial Considerations

Q. BEFORE ADDRESSING THE SPECIFIC ASPECTS OF THIS PROCEEDING, PLEASE EXPLAIN THE CONNECTION BETWEEN THE COST OF CAPITAL AND A UTILITY'S COST OF SERVICE.

A. Under the cost-of-service ratemaking paradigm, the development of utility rates begins with determining the utility's total cost to serve customers. This is known as the revenue requirement, since the utility's revenues must be sufficient to recover its costs to serve customers. The revenue requirement consists of four components: (1) operating and maintenance ("O&M") expenses, (2) taxes, (3) the return *of* capital through depreciation expense, and (4) the return *on* capital through the regulated return on rate base. The return on rate base is calculated as the weighted average cost of capital multiplied by the rate base. The return on capital must be sufficient to allow the utility to repay its debt obligations and compensate equity investors for the use of their financial capital. From that important perspective, the return on capital reflects a cost to the utility just as any other component of the revenue requirement.

Q. PLEASE EXPLAIN THE COST OF CAPITAL CONCEPTUALLY.

A. The cost of capital is the return that investors require to commit capital to a firm. Investors will provide funds to a firm only if the return that they *expect* is equal to, or greater than, the return that they *require* to accept the risk of investing capital in the firm. Simply, the cost of capital is the required rate of return prevailing in the capital markets on alternative investments of similar risk.[8] Conceptually, the cost of capital is: (1) forward looking; (2) an opportunity cost; (3) determined in the capital markets, and (4) dependent on, and proportional to, the risk of the investment.[9]

Because the cost of equity is expectational and premised on the principle of opportunity costs, it cannot be precisely quantified. Instead, it must be estimated by applying market data to various financial models that are simplified representations of investor behavior and expectations. Moreover, equity investors have a subordinate claim to cash flows owed to debt investments and other claims; the uncertainty (or risk) associated with those residual cash flows determines the cost of equity. In the end, the cost of equity should reflect the return that investors require considering the subject company's risk profile and the returns available on comparable investments.

Q. HOW IS THE COST OF EQUITY ESTIMATED IN REGULATORY PROCEEDINGS?

A. Regulated utilities primarily use long-term capital (*e.g.*, common stock and long-term debt) to finance their permanent rate base. The rate of return for a regulated utility is calculated as its

[8] Lawrence A. Kolbe, James A. Read, Jr., and George R. Hall, The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press, Cambridge, MA, at 13 (1985).

[9] Lawrence A. Kolbe, James A. Read, Jr., and George R. Hall, The Cost of Capital – Estimating the Rate of Return for Public Utilities, The MIT Press, Cambridge, MA, at 13 (1985).

weighted average cost of capital, in which the costs of the individual sources of capital are weighted by their respective book values.

The cost of equity reflects the cost of raising and retaining equity capital and is estimated by using one or more market-based analytical approaches. Although quantitative models are used to estimate the cost of equity, it cannot be precisely quantified through a strict mathematical exercise. As such, a reasonable and appropriate ROE reflects the financial, economic, and regulatory environment in which the estimate is developed, as well as the subject company's risk profile.

Q. PLEASE BRIEFLY SUMMARIZE THE GUIDELINES USED IN ESTABLISHING THE COST OF CAPITAL FOR A REGULATED UTILITY.

A. Public utility regulation is rooted in the principle that utilities are entitled to a fair rate of return sufficient to attract the capital required to provide safe and reliable public utility service for customers at reasonable rates. The U.S. Supreme Court ("Supreme Court") established the guiding principles for establishing a fair return for capital in two seminal cases: (1) *Bluefield Water Works and Improvement Co. v. Public Service Comm'n.* ("*Bluefield*");[10] and (2) *Federal Power Comm'n v. Hope Natural Gas Co.* ("*Hope*").[11] In *Bluefield*, the Court stated:

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

[10] *See, Bluefield Water Works and Improvement Co. v. Public Service Comm'n*., 262 U.S. 679, 692 (1923).
[11] *See, Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591, 603 (1944).

discharge of its public duties.[12]

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

In *Hope*, the Supreme Court reiterated the three primary standards for a regulated rate of return:

> [Th]e return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return, moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and to attract capital.[13]

In summary, the Supreme Court has recognized that the fair return should be: (1) commensurate with returns investors expect to earn on other investments of similar risk (the "comparable return" standard); (2) sufficient to assure confidence in the company's financial integrity (the "financial integrity" standard); and (3) adequate to maintain and support the company's credit and to attract capital (the "capital attraction" standard). Importantly, a fair and reasonable rate of return satisfies all three standards.

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

A. Yes, it has. The Commission upholds the precedents of the *Hope* and *Bluefield* cases and regularly acknowledges that a utility is entitled to a fair and reasonable return. For example, in

[12] *Bluefield Water Works and Improvement Co. v. Public Service Comm'n*., 262 U.S. 679, 692 (1923).
[13] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603 (1944).

its September 2024 order in Peoples' last filed rate case, the Commission stated, "In determining a fair rate of return, the Commission is guided by the criteria provided by the United States Supreme Court in the landmark cases of *Bluefield Water Works and Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679 (1923) and *Federal Power Comm'n v. Hope Natural Gas Co*., 320 U.S. 591 (1944)."[14] Based on those standards, the authorized ROE should provide Peoples with the opportunity (which is not a guarantee) to earn a fair and reasonable return and should enable efficient access to external capital under a variety of market conditions.

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

A. Regulated utilities have a legal obligation to serve regardless of prevailing economic and capital market conditions. Unlike non-regulated firms, a regulated utility cannot decide to whom it provides utility service in its footprint, how much service it delivers, nor when it provides service. Because utilities are one of the most capital-intensive sectors, they must ensure they have access to external financial capital on reasonable terms in all market environments, including when capital markets are volatile or constrained (*e.g*., during periods of high inflation and interest rates, global pandemics, changes in government, and economic recessions). The ability to attract adequate capital at reasonable terms allows a utility to maintain its financial integrity while funding its operations in a safe and reliable manner. As

[14] *Pa. PUC v. Peoples Natural Gas Company, LLC*, Opinion and Order, Docket No. R-2023-3044549, at 7 (September 12, 2024).

discussed above, and in keeping with the *Hope* and *Bluefield* standards, that return should be commensurate with the returns expected for investments of equivalent risk.

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

Further, the financial community carefully monitors utility companies' current and expected financial conditions, as well as the regulatory environment in which those companies operate. In that respect, the regulatory environment is one of the most important factors considered in both debt and equity investors' assessments of risk.[15] That consideration is especially important during uncertain economic and financial conditions in which the utility may require access to capital markets.

The outcome of the Commission's order in this case, therefore, should provide Peoples with the opportunity to earn an ROE that is: (1) adequate to attract capital at reasonable terms, (2) sufficient to ensure its financial integrity, and (3) commensurate with returns on investments in enterprises having corresponding risks. To the extent Peoples has a reasonable opportunity to earn its market-based cost of equity, neither customers nor shareholders are disadvantaged. In fact, a return that is adequate to attract capital at reasonable terms enables

[15] *See, e.g.*, Moody's Ratings, *Rating Methodology: Regulated Gas and Electric Utilities*, at 7 (August 6, 2024).

Peoples to provide customers with safe, reliable service while maintaining its financial integrity.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE REGULATORY PRINCIPLES PERTAINING TO THE COST OF CAPITAL FOR A PUBLIC UTILITY?

A. Congruent with other costs in a utility's cost of service, the regulated return on rate base is a cost that Peoples incurs as part of its normal operations, including the need to compensate equity investors for the use of their capital. Under the *Hope* and *Bluefield* standards, the cost of equity authorized for Peoples in this proceeding should be: (1) adequate to attract capital at reasonable terms; (2) sufficient to ensure its financial integrity; and (3) commensurate with returns on investments having similar risks.

Because utilities are capital intensive and investors have many investment alternatives, the Company's financial profile must be adequate on a relative basis to ensure its ability to attract capital under a variety of economic and financial market conditions. The Commission's decision regarding the authorized ROE and capital structure in this proceeding will directly affect the Company's ability to attract the capital needed to maintain and enhance service to customers.

B. Proxy Group Selection

Q. WHY IS IT NECESSARY TO SELECT A GROUP OF PROXY COMPANIES TO DETERMINE THE COST OF EQUITY FOR PEOPLES?

A. Because the ROE is a market-based concept, and Peoples is not a separate entity with its own stock price, it is necessary to establish a group of companies that are both publicly traded and

comparable to the Company in certain fundamental respects to serve as its "proxy" in the ROE estimation process. Even if the Company were a publicly traded entity, short-term events could bias its market value during a given period. A significant benefit of using a proxy group is that it moderates the effects of anomalous, temporary events associated with any one company. As a result of the screening criteria used to select the proxy group, the companies used in my ROE analyses have similar business and operating characteristics to Peoples and thus provide a reasonable basis for the derivation and assessment of ROE estimates.

Q. PLEASE PROVIDE A SUMMARY PROFILE OF PEOPLES.

A. Peoples is a wholly owned subsidiary of PNG Companies LLC, which is in turn owned by Essential. Peoples provides natural gas distribution services to approximately 740,000 customers in portions of Pennsylvania and Kentucky.[16] Peoples is not independently rated; the current issuer credit ratings for PNG Companies LLC and Essentialare shown in Figure 4 below:

Figure 4: Current Long-term Issuer Credit Ratings[17]

Rating Agency	PNG Companies LLC	Essential Utilities, Inc.
S&P Global Ratings	A- (Stable)	A- (Positive)
Moody's Ratings ("Moody's")	Baa2 (Negative)	Baa2 (Negative)

Q. DOES THE FACT THAT PEOPLES IS AN INDIRECT SUBSIDIARY OF ESSENTIAL AFFECT ITS COST OF EQUITY?

A. No. The cost of equity depends on the risk of a firm's operations and the assets supporting those operations. In other words, the cost of equity depends on the *use* of capital, not on the

[16] https://www.peoples-gas.com/about/
[17] Sources: S&P and Moody's.

source of capital. Therefore, the Company's corporate structure, including whether it (or its parent) is privately held or publicly traded, does not affect the analysis. That is, the ROE is not determined by reference to Peoples' parent company.

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

A. Because estimating the cost of equity is a comparative exercise, it is necessary to develop a proxy group of companies with risk profiles that are reasonably comparable to the subject company. As each company is unique, no two companies will have identical business and financial risk profiles. In selecting a proxy group, my objective is to balance the competing interests of selecting companies that are representative of the risks and prospects faced by Peoples, while at the same time ensuring that there is a sufficient number of companies in the proxy group. To develop the proxy group, I began with the nine companies that Value Line classifies as "Natural Gas Utilities" and then screened companies according to the following criteria to develop a proxy group reasonably comparable to Peoples:

1. Pays quarterly cash dividends that have not been reduced or omitted in the last two years;
2. Maintains an investment grade long-term issuer rating (BBB- or higher from S&P or Baa3 or higher from Moody's) from both S&P and Moody's;
3. Is consistently covered by more than one equity analyst;
4. Has positive earnings growth rates published by at least two of the following sources: Value Line Investment Survey ("Value Line"), S&P Capital IQ, and Zacks Investment Research ("Zacks");

5. Regulated net operating income makes up the majority of the consolidated company's net operating income, on average, for the three years ended 2024;
6. Natural gas distribution net operating income makes up a majority of the consolidated company's net operating income, on average, for the three years ended 2024; and
7. Has not had a recent significant merger activity or transaction or a recent significant financial event that could affect its market data or financial condition.

Q. DO YOU INCLUDE ESSENTIAL IN YOUR PROXY GROUP?

A. No. Essential is not classified by Value Line as a natural gas utility, nor does it meet my screening criterion of having at least 50 percent of net operating income from regulated natural gas utility operations. Further, it would be circular logic to include Peoples' ultimate parent company in my analysis.

Q. WHICH COMPANIES MEET YOUR SCREENING CRITERIA?

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

Figure 5: Proxy Group Screening Results

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

Q. DOES THE PROXY GROUP OF SEVEN COMPANIES PROVIDE A REASONABLE BASIS TO ESTIMATE PEOPLES' COST OF EQUITY?

A. Yes. As noted earlier, my objective is to balance the competing interests of selecting companies that are representative of Peoples' risks, while also ensuring that there is a sufficient number of companies in the proxy group. The analyses performed in estimating the ROE are more likely to be representative of the subject utility's cost of equity to the extent that the selected proxy companies are fundamentally comparable to the subject utility. A larger proxy group does not necessarily improve the representative nature of the proxy group. Including companies whose fundamental comparability may be questionable simply for the purpose of expanding the number of observations does not improve the reliability of the results or the conclusions drawn from them. On balance, the proxy group is reasonably comparable to Peoples and is an appropriate set of companies to use in the ROE estimation process.

Q. DOES YOUR SCREENING CRITERIA RESULT IN A GROUP OF COMPANIES THAT INVESTORS WOULD VIEW AS COMPARABLE TO PEOPLES?

A. Yes. The proxy group has been selected to develop a group of companies that are reasonably comparable (but not identical) to the financial and operational characteristics of Peoples in

aggregate. The screening criterion requiring an investment grade credit rating ensures that the proxy companies, like Peoples, are generally in sound financial condition. Additionally, the criterion based on the percentage of net operating income from regulated natural gas distribution operations differentiates between utilities that derive a meaningful proportion of income from regulated natural gas distribution operations from those with substantial unregulated risks. These screens collectively reflect the risk factors that investors consider in making their investment decisions in natural gas utility companies.

C. Cost of Equity Models

Q. WHAT ANALYTICAL APPROACHES DO YOU RELY ON TO DETERMINE THE COMPANY'S ROE?

A. As discussed earlier, I rely on the constant growth and quarterly growth forms of the DCF model, the traditional and empirical forms of the CAPM, and the Risk Premium approach. The models I apply are commonly used in practice, as well as in regulatory proceedings.[18] Additionally, each model provides a different perspective of investors' views of risk and return. Therefore, using multiple methods provides a more comprehensive, and therefore more reliable, perspective on investors' return requirements.

1. Constant Growth Discounted Cash Flow Model

Q. PLEASE DESCRIBE THE CONSTANT GROWTH DCF APPROACH.

A. The Constant Growth DCF model is based on the theory that a stock's current price represents the present value of all expected future cash flows. In its simplest form, the Constant Growth

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

DCF model expresses the cost of equity shown in Equation [1] below sets the ROE equal to the expected dividend yield plus the expected long-term annual growth rate in perpetuity:

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

where:

k = the required market cost of equity,

D_0 = the current annualized dividend,

P = the current stock price, and

g = the expected long-term annual growth rate.

Q. WHAT ASSUMPTIONS UNDERLIE THE CONSTANT GROWTH DCF MODEL?

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

Q. WHAT MARKET DATA DO YOU USE AS INPUTS TO YOUR CONSTANT GROWTH DCF ANALYSIS?

A. I calculate the Constant Growth DCF result for each of the proxy companies using the following inputs:

- The average daily closing prices for the 30-, 90-, and 180-trading days ended January 30, 2026 for the term P_0;
- The current quarterly dividend as of January 30, 2026 multiplied by 4, for the term D_0; and

- Long-term earnings per share ("EPS") growth rate projections as of January 30, 2026 reported by Zacks, S&P Capital IQ, and Value Line.

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

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

Q. HOW DO YOU CALCULATE THE EXPECTED DIVIDEND YIELD OVER THE COMING YEAR?

A. Because utility companies tend to increase their quarterly dividends at different times throughout the year, it is reasonable to assume that dividend increases will be evenly distributed over calendar quarters. Given that assumption, it is appropriate to calculate the expected dividend yield by applying one-half of the long-term growth rate to the current dividend yield. That adjustment ensures that the expected dividend yield is, on average, representative of the coming 12-month period.

Q. WHY ARE ANALYSTS' PROJECTED EPS GROWTH RATES THE APPROPRIATE MEASURE OF LONG-TERM GROWTH IN THE CONSTANT GROWTH DCF MODEL?

A. In its Constant Growth form, the DCF model (*i.e.*, as presented in Equation [1] above) assumes a single expected growth estimate in perpetuity, which assumes a fixed payout ratio, and the

same constant growth rate in EPS, dividends per share, and book value per share. In the long run, dividend growth can only be sustained by earnings growth.

Further, academic studies have clearly and consistently shown that measures of earnings and cash flow are strongly related to returns, and that analysts' forecasts of growth are superior to other measures of growth in predicting stock prices.[19] For example, the research of Vander Weide and Carleton demonstrates that earnings growth projections have a statistically significant relationship to stock valuation levels, while dividend growth rates do not.[20] An academic study from The Journal of Portfolio Management found that securities analysts' growth estimates have been shown to be more accurate predictors of future returns than historical earnings and dividend growth rates, as well as sustainable growth rates.[21] Additionally, a 2002 study in the Journal of Accounting Research examined "the valuation performance of a comprehensive list of value drivers" and found that "forward earnings explain stock prices remarkably well" and were generally superior to other value drivers analyzed.[22] A 2013 study from the journal Contemporary Accounting Research found that the sell-side analysts with the most accurate stock price targets were those whom the researchers found to

[19] *See, e.g.*, Andreas C. Christofi, Petros C. Christofi, Marcus Lori and Donald M. Moliver, *Evaluating Common Stocks Using Value Line's Projected Cash Flows and Implied Growth Rate*, Journal of Investing (Spring 1999); Harris and Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management at 21 (Summer 1992); and Vander Weide and Carleton, *Investor Growth Expectations: Analysts vs. History*, The Journal of Portfolio Management (Spring 1988); Robert S. Harris, *Using Analysts' Growth Forecasts to Estimate Shareholder Required Rate of Return*, Financial Management (Spring 1986).

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

[21] David A. Gordon, Myron J. Gordon & Lawrence I. Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989.

[22] Liu, Jing, et al., "Equity Valuation Using Multiples," Journal of Accounting Research, Vol. 40 No. 1, March 2002.

have more accurate earnings forecasts.[23] Further, academic studies suggest that investors base their investment decisions on analysts' expectations of growth in earnings.[24]

Lastly, the only forward-looking growth rates that are available on a consensus basis are analysts' EPS growth rates. The fact that earnings growth projections are the only widely available estimates of growth further supports the conclusion that earnings growth is the most meaningful measure of growth among the investment community. For these reasons, earnings growth is the appropriate measure of long-term growth in the DCF model.

Q. WHAT ARE THE RESULTS OF YOUR CONSTANT GROWTH DCF ANALYSIS?

A. To provide a spectrum of DCF-based ROE estimates, I calculate the low, mean, and high Constant Growth DCF result for each proxy company. The mean result combines the average of the three EPS growth rate estimates with each proxy company's expected dividend yield. The high DCF result adds the maximum EPS growth rate estimate with each proxy company's expected dividend yield. Similarly, the low DCF result adds the minimum EPS growth rate estimate for each proxy company to the expected dividend yield. In developing my ROE recommendation, I rely on the average of the mean and median proxy group Constant Growth DCF results using the mean EPS growth rates (*see,* Figure 6, below). By relying on the average of the mean and median proxy group results, I consider the individual DCF results of each proxy company while mitigating the effect of the highest and lowest estimates.

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[23] Gleason, C.A., et al., "Valuation Model Use and the Price Target Performance of Sell Side Equity Analysts," Contemporary Accounting Research, Vol. 30 No. 1, (Spring 2013).

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

Figure 6: Constant Growth DCF Results Using Mean EPS Growth Rates[25]

	Mean	Median	Average of Mean & Median
30-Day Average	11.08%	10.36%	10.72%
90-Day Average	11.07%	10.37%	10.72%
180-Day Average	11.20%	10.64%	10.92%
		Average	10.79%

2. Quarterly Growth DCF Model

Q. PLEASE BRIEFLY DESCRIBE THE QUARTERLY GROWTH DCF MODEL.

A. As noted earlier, the Constant Growth DCF model is based on several limiting assumptions, one of which is that dividends are paid annually. However, most dividend-paying companies, including utilities, pay dividends on a quarterly (as opposed to an annual) basis. Although the dividend yield adjustment discussed earlier is meant to address that assumption (by increasing the current dividend yield by one-half of the expected growth rate), it does not fully account for the quarterly receipt and reinvestment of dividends. Consequently, the Constant Growth DCF model likely understates the cost of equity.

The Quarterly Growth DCF model specifically incorporates investors' expectations of the quarterly payment of dividends, and the associated quarterly compounding of those dividends as they are reinvested at the required ROE. As noted by Dr. Roger Morin:

> Clearly, given that dividends are paid quarterly and that the observed stock price reflects the quarterly nature of dividend payments, the market-required return must recognize quarterly compounding, for the investor receives dividend checks and reinvests the proceeds on a quarterly schedule ... The annual DCF model inherently understates the investors' true return because it

[25] Exhibit JEN-2.

assumes all cash flows received by investors are paid annually.[26]

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

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

$$D = d_1(1+k)^{0.75} + d_2(1+k)^{0.50} + d_3(1+k)^{0.25} + d_4(1+k)^{0} \quad [2]$$

where:

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

k = the required market cost of equity.[27]

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

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

A. My Quarterly Growth DCF results are summarized in Figure 7, below (*see also* Exhibit JEN-3). As with my Constant Growth DCF results, I rely on the average of the mean and median proxy group results.

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

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

Figure 7: Quarterly Growth DCF Results[28]

	Mean	Median	Average of Mean & Median
30-Day Average	11.28%	10.63%	10.95%
90-Day Average	11.27%	10.66%	10.96%
180-Day Average	11.41%	10.96%	11.18%
		Average	11.03%

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

Q. PLEASE DESCRIBE THE GENERAL FORM OF THE CAPM.

A. The CAPM is a risk premium method that estimates the cost of equity for a given security as a function of a risk-free return plus a risk premium to compensate investors for the non-diversifiable or "systematic" risk of that security. As shown in Equation [3], the CAPM is defined by four components, each of which is meant to be a forward-looking estimate:

$$K_e = r_f + \beta\ (r_m - r_f) \quad [3]$$

where:

K_e = the required market cost of equity for a security;

β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

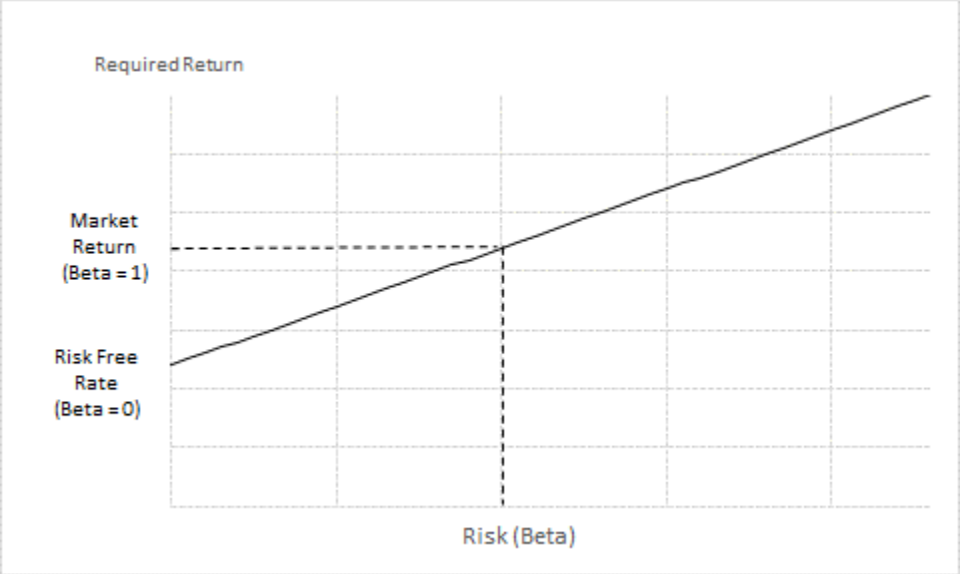
r_m = the required return on the market as a whole.

Equation [3] describes the Security Market Line ("SML"), or the CAPM risk-return relationship, depicted in Figure 8 below. The intercept is the risk-free rate (r_f) that has a Beta

[28] Exhibit JEN-3.

coefficient of zero, and the slope is the expected market risk premium ($r_m - r_f$). As shown in Figure 8, the slope of the line is upward sloping, illustrating the principle that investments of higher risk require a higher return. By definition, r_m, the return on the market, has a Beta coefficient of 1.00.

Figure 8: Security Market Line



The CAPM assumes that all non-market or unsystematic risk can be eliminated through diversification. The risk that cannot be eliminated through diversification is called market, or systematic, risk. Therefore, the CAPM assumes that investors require compensation only for systematic, or market, risk. Systematic (or non-diversifiable) risk is measured by the Beta coefficient, which is defined as:

$$\beta_j = \frac{\sigma_j}{\sigma_m} \times \rho_{j,m} \qquad [4]$$

where:

β_j = the Beta coefficient of company "*j*";

σ_j = the standard deviation of returns for company "*j*";

σ_m = the standard deviation of returns for the broad market ("*m*," as measured, for example, by the S&P 500 Index); and

$\rho_{j,m}$ = the correlation of returns between company j and the broad market, "m".

The Beta coefficient, therefore, represents both relative volatility (*i.e.*, the standard deviation) of returns, and the correlation in returns between the subject company and the overall market. Intuitively, higher Beta coefficients indicate that the subject company's returns have been relatively volatile and have moved in tandem with the overall market.

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

A. I apply two estimates of the risk-free rate: (1) the current 30-day average yield on 30-year Treasury bonds (*i.e.*, 4.83 percent)[29] and (2) a projected 30-year Treasury yield (*i.e.*, 4.68 percent).[30]

Q. WHY DO YOU RELY ON THE 30-YEAR TREASURY YIELD AS THE RISK-FREE RATE IN YOUR CAPM ANALYSIS?

A. In determining the security most relevant to the application of the CAPM, the term (or maturity) should approximate the life of the underlying investment. Natural gas utilities are typically long-duration investments; therefore, the 30-year Treasury yield is more suitable for the risk-free rate applied in the CAPM.

[29] Source: Federal Reserve Bank of St. Louis (FRED) Economic Database, as of January 30, 2026.

[30] The average of: (1) the average projected 30-year Treasury yield for the six quarters ended Q2 2027 and (2) the average long-term projected 30-year Treasury yield for the years 2027-2031 and 2032-2036 reported by Blue Chip Financial Forecasts. *See,* Blue Chip Financial Forecasts Vol. 45, No. 2, January 30, 2026 at 2, and Vol. 44, No. 12, December 1, 2025, at 14.

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

A. As shown in Exhibit JEN-5, I rely on two estimates of the Beta coefficient. I first consider the average 5-year Beta coefficients from Value Line and Bloomberg for each proxy company as of January 30, 2026. Beta coefficients from both services are calculated using weekly returns over a five-year period, adjusted to reflect the tendency of Beta coefficients to regress toward the market mean of 1.00. As a second measure, I also consider Bloomberg Beta coefficients calculated using weekly return data over the ten years ended January 30, 2026, rather than a five-year period.

Q. WHAT ESTIMATES OF THE MARKET RETURN DO YOU USE TO CALCULATE THE MARKET RISK PREMIUM?

A. I apply two estimates of the market return. The first estimate calculates the market capitalization-weighted ROE of the S&P 500 Index by applying the Constant Growth DCF model described earlier to the S&P 500 Index. The second estimate applies the long run historical arithmetic average market return of 12.23 percent between 1926 and 2025 reported by Kroll (formerly Duff & Phelps).[31]

Q. PLEASE EXPLAIN YOUR FORWARD-LOOKING DCF APPROACH TO ESTIMATING THE MARKET RETURN.

A. Using the Constant Growth DCF model described earlier, I develop three estimates of the market return for the S&P 500 Index. I consider projected earnings growth rates and dividend yields from three sources: (1) S&P's Earnings and Estimates Report; (2) Bloomberg Professional; and (3) Value Line by applying dividend yields from S&P Capital IQ and

[31] Source: Kroll, Cost of Capital Navigator.

projected earnings growth rates from S&P, Bloomberg, and Value Line. As shown in Figure 9 below, these independent estimates of the market return range from 16.38 percent to 19.08 percent (*see also* Exhibit JEN-4). To be conservative, I rely on Value Line's market return estimate of 16.38 percent in my CAPM analysis.

Figure 9: DCF-Based Forward Market Return Estimates[32]

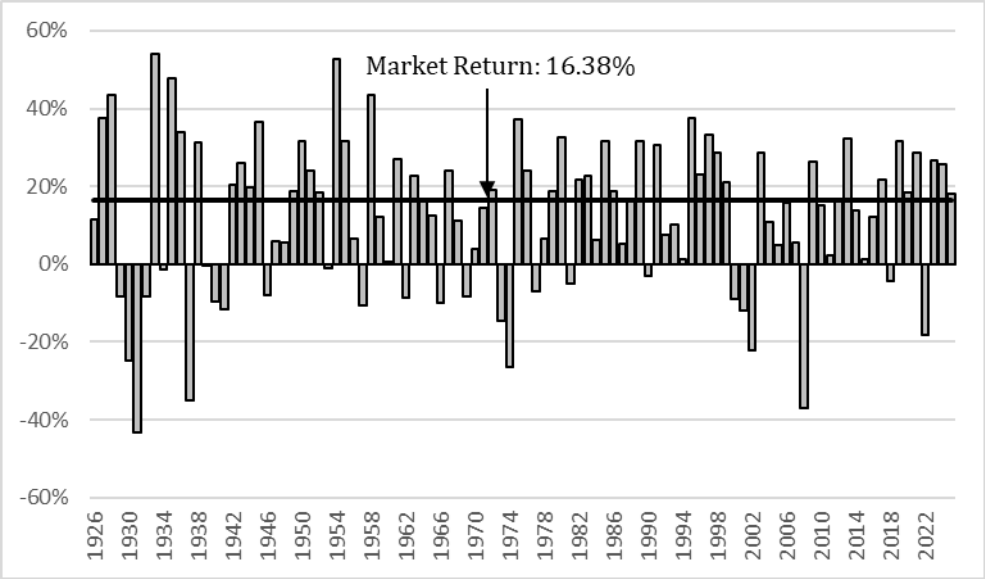
Source	Market Return
Value Line	16.38%
Bloomberg Professional	19.08%
S&P Earnings & Estimates Report	18.56%

Q. IS THE VALUE LINE DCF-BASED MARKET RETURN ESTIMATE OF 16.38 PERCENT CONSISTENT WITH ACTUAL OBSERVED RETURNS ON THE MARKET?

A. Yes, it is. As shown in Figure 10 below, a market return estimate of 16.38 percent or higher occurred in 48 of the last 100 years (*i.e.,* nearly 50 percent of the time). Since 2009, the annual market return has averaged 15.72 percent, and equaled or exceeded 16.38 percent in nine of the last 17 years. In other words, an annual market return of 16.38 percent, or higher, has occurred frequently and is not an outlier.

[32] Exhibit JEN-4.

Figure 10: Annual Market Return (1926 – 2025)[33]



Q. WHY DO YOU ALSO CONSIDER THE LONG-TERM ARITHMETIC AVERAGE HISTORICAL RETURN ON THE MARKET OF 12.23 PERCENT AS AN ALTERNATE ESTIMATE OF THE MARKET RETURN?

A. My objective is to develop a reasonable estimate of the market return over the long term to calculate a market risk premium. Because the cost of equity is forward looking, any estimate – whether based on historical or projected data – assumes the estimate reflects investors' expectations into the future. Although the 16.38 percent forward market return estimate is highly consistent with historically observed market returns (as shown in Figure 10 above), it is above the long-term arithmetic annual average market return. Therefore, it may be reasonable to expect that, over the long term, the market return will revert to its long-run historical arithmetic average. From that perspective, the application of the long-run historical

[33] Source: Kroll, 2023 SBBI Yearbook, Appendix A-1, (years 1926-2022); Cost of Capital Navigator (2023-2025 data).

arithmetic average market return as an alternate estimate of the market return is prospective in nature.

Q. WITH THE RISK-FREE RATES AND MARKET RETURN ESTIMATES DESCRIBED ABOVE, HOW DO YOU CALCULATE THE MARKET RISK PREMIUM?

A. I apply two estimates of the risk-free rate and two estimates of the market return. Combined, those variables produce four estimates of the market risk premium, ranging from 7.40 percent to 11.70 percent, as shown below in Figure 11.

Figure 11: Market Risk Premium Estimates

	Current Risk-Free Rate (4.83%)	**Projected Risk-Free Rate (4.68%)**
Value Line DCF-based Forward Market Return (16.38%)	11.55%	11.70%
Long-Term Historical Average Market Return (12.23%)	7.40%	7.56%

Q. DO YOU CONSIDER ANOTHER FORM OF THE CAPM?

A. Yes, I also consider the Empirical CAPM ("ECAPM") approach, which calculates the product of the adjusted Beta coefficient and the Market Risk Premium and applies a weight of 75.00 percent to that result. The model then applies a 25.00 percent weight to the Market Risk Premium, without any effect from the Beta coefficient.[34] The results of the two calculations are summed, along with the risk-free rate, to produce the ECAPM result, as noted in Equation [5] below:

$$K_e = r_f + 0.75\beta(r_m - r_f) + 0.25(r_m - r_f) \quad [5]$$

where:

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

K_e = the required market cost of equity for a security;

β = the Beta coefficient of that security;

r_f = the risk-free rate of return; and

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

Q. WHAT IS THE BENEFIT OF THE ECAPM APPROACH?

A. The ECAPM addresses the tendency of the CAPM to underestimate the cost of equity for companies, such as regulated utilities, with relatively low Beta coefficients. As discussed below, the ECAPM recognizes academic research that indicates the risk-return relationship is flatter than that estimated by the CAPM, and that the CAPM underestimates the Alpha (α), or the constant return term.[35]

Numerous tests of the CAPM have measured the extent to which security returns and Beta coefficients are related as predicted by the CAPM. The ECAPM method reflects the finding that the actual SML described by the CAPM formula is not as steeply sloped as the predicted SML.[36] Fama and French state that "[t]he returns on the low beta portfolios are too high, and the returns on the high beta portfolios are too low."[37] Similarly, Dr. Morin states:

> With few exceptions, the empirical studies agree that . . . low-beta securities earn returns somewhat higher than the CAPM would predict, and high-beta securities earn less than predicted. . . .
>
> Therefore, the empirical evidence suggests that the expected return on a security is related to its risk by the following approximation:
>
> $$K = R_F + x\,(R_M - R_F) + (1-x)\beta(R_M - R_F)$$
>
> where x is a fraction to be determined empirically. The value of x that best

[35] Roger A. Morin, Ph.D., New Regulatory Finance, at 191 (2006).

[36] Roger A. Morin, Ph.D., New Regulatory Finance, at 175 (2006). The Security Market Line plots the CAPM estimate on the Y-axis, and Beta coefficients on the X-axis as shown in Figure 8.

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

explains the observed relationship Return = 0.0829 + 0.0520 β is between 0.25 and 0.30. If x = 0.25, the equation becomes:

$$K = R_F + 0.25(R_M - R_F) + 0.75\ \beta(R_M - R_F)$$ [38]

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

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

> Some have argued that the use of the ECAPM is inconsistent with the use of adjusted betas, such as those supplied by Value Line and Bloomberg. This is because the reason for using the ECAPM is to allow for the tendency of betas to regress toward the mean value of 1.00 over time, and, since Value Line betas are already adjusted for such trend, an ECAPM analysis results in double-counting. This argument is erroneous. Fundamentally, the ECAPM is not an adjustment, increase or decrease, in beta. This is obvious from the fact that the expected return on high beta securities is actually lower than that produced by the CAPM estimate. The ECAPM is a formal recognition that the observed risk-return tradeoff is flatter than predicted by the CAPM based on myriad empirical evidence. The ECAPM and the use of adjusted betas comprised two separate features of asset pricing. Even if a company's beta is estimated accurately, the CAPM still understates the return for low-beta stocks. Even if the ECAPM is used, the return for low-beta securities is understated if the betas are understated. Referring back to Figure 6-1, the ECAPM is a return (vertical axis) adjustment and not a beta (horizontal axis) adjustment. Both adjustments are necessary.[39]

Therefore, it is appropriate to rely on adjusted Beta coefficients in both the CAPM and ECAPM.

[38] Roger A. Morin, Ph.D., New Regulatory Finance at 175, 190 (2006).
[39] Roger A. Morin, Ph.D., New Regulatory Finance, at 191 (2006).

Q. ARE YOU AWARE OF ACADEMIC STUDIES THAT SUPPORT THE USE OF THE ECAPM FOR UTILITIES?

A. Yes, I am. In a 2011 study by Stéphane Chrétien and Frank Coggins, the authors studied the CAPM's ability to estimate the risk premium for the utility industry in particular subgroups of utilities.[40] The study considered the traditional CAPM approach, the Fama-French three-factor model, and a model similar to the ECAPM. In the study, the ECAPM relied on adjusted Beta coefficients similar to Value Line's approach. As Chrétien and Coggins found, the ECAPM significantly outperformed the traditional CAPM model at predicting the observed risk premium for the various utility subgroups.

Q. DO INVESTORS USE THE ECAPM APPROACH?

A. Yes. Investors do use the ECAPM, or models that are very similar and assume a flatter security market line as the ECAPM does. For example, in chapter four of Professional Investment Portfolio Management, Kolari, Liu, and Pynnönen detail how they worked with the pension investment division at the Teachers Retirement System of Texas to manage about $100 million using the ZCAPM model (which is a special case of the zero-beta CAPM) from 2012 to 2014.[41]

Q. HAVE ANY REGULATORY COMMISSIONS EXPLICITLY ACCEPTED THE ECAPM?

A. Yes. The New York Public Service Commission ("NYPSC") relies on both the traditional and empirical forms of the CAPM.[42] Additionally, the North Carolina Utilities Commission

[40] Stéphane Chrétien and Frank Coggins, *Cost of Equity for Energy Utilities: Beyond The CAPM*, Energy Studies Review, Vol. 18, No. 2 (2011).

[41] Kolari, James W., Liu, Wei, and Pynnönen, Seppo, Professional Investment Portfolio Management, "A New Asset Pricing Model: The ZCAPM," 2023, at 87.

[42] *See*, New York Public Service Commission, Case 16-G-0058, P*roceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of KeySpan Gas East Corporation d/b/a National Grid for Gas Service*, Order Adopting Terms of Joint Proposal and Establishing Gas Rate Plans, at 32 (December 16, 2016).

("NCUC") accepted the ECAPM in recent orders for Duke Energy Carolinas and Duke Energy Progress.[43] I note that both the NYPSC and NCUC used adjusted Beta coefficients with the ECAPM analysis. Additionally, I am aware that the ECAPM has been accepted by regulatory commissions in Alaska, Maryland, and Mississippi.[44] Lastly, I am aware the ECAPM has been presented by state regulatory commission staff in Maryland, Nevada, and by the Department of Commerce in Minnesota.[45] In summary, the ECAPM is an accepted approach used by investors and should be accepted by the Commission.

Q. WHAT ARE THE RESULTS OF YOUR CAPM AND ECAPM ANALYSES?

A. I apply the same market return, Beta coefficients, and risk-free rates described earlier in my ECAPM analysis to Equation [5] above. The results of my CAPM and ECAPM analyses are summarized in Figure 12 below.

[43] *See*, *In the Matter of Application of Duke Energy Carolinas, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Docket No. E-7, Sub 1276, Order Accepting Stipulations, Granting Partial Rate Increase, Requiring Public Notice, And Modifying Lincoln CT CPCN Conditions, at 209-210 (December 18, 2023); *In the Matter of Application of Duke Energy Progress, LLC for Adjustment of Rates and Charges Applicable to Electric Service in North Carolina and Performance-Based Regulation*, Docket No. E-2, Sub 1300, Order Accepting Stipulations, Granting Partial Rate Increase, and Requiring Public Notice, at 162-163 (August 18, 2023).

[44] *See,* Regulatory Commission of Alaska, Docket No. P-97-4, Order No. 151, at 146 (November 27, 2002); Maryland Public Service Commission, Case No. 9311, Order No. 85724, at 105 (July 12, 2013); Mississippi Public Service Commission, Docket No. 01-UN-0548, *Notice of Intent of Mississippi Power Company to Change Rates for Electric Service in its Certificated Areas in the Twenty-Three Counties of Southeast Mississippi*, Final Order, December 3, 2001, at 19 (December 3, 2001).

[45] *See,* Maryland Public Service Commission, Case No. 9311, Order No. 85724, at 88; Minnesota Public Utilities Commission, MPUC Docket No. G011/GR-15-736, *Findings of Fact, Conclusions of Law, and Recommendation*, August 19, 2016, at 29 (August 19, 2016); Public Utilities Commission of Nevada, Docket No. 12-02019, Second Modified Final Order, at 36 (March 20, 2013).

Figure 12: Summary of CAPM and ECAPM Results[46]

	Current 30-Year Treasury Yield (4.83%)	Projected 30-Year Treasury Yield (4.68%)	Average
CAPM: Forward Market Return	13.11%	13.06%	13.09%
ECAPM: Forward Market Return	13.93%	13.89%	13.91%
CAPM: Historical Market Return	10.14%	10.09%	10.11%
ECAPM: Historical Market Return	10.66%	10.63%	10.64%
Average			11.94%

4. Risk Premium Approach

Q. PLEASE DESCRIBE THE RISK PREMIUM APPROACH.

A. The Risk Premium approach is based on the basic financial principle of risk and return, which states that equity investors require a premium over the return required as a bondholder to account for the incremental residual risk associated with equity ownership. Risk premium approaches estimate the cost of equity as the sum of the equity risk premium and the yield on a particular class of bonds.

Q. PLEASE EXPLAIN HOW YOU PERFORM YOUR RISK PREMIUM ANALYSIS.

A. I first define the equity risk premium as the difference between the authorized ROE and the then-prevailing 30-year Treasury bond yield, using the authorized ROE for 1,389 natural gas utility rate proceedings between January 1, 1980, and January 31, 2026. To reflect the prevailing level of bond yields during the pendency of the proceedings, I calculate the average

[46] Exhibit JEN-5. Results reflect the average of the proxy group mean and median CAPM and ECAPM results using 5-year and 10-year Beta coefficients.

30-year Treasury yield over the average lag period between the filing of the rate case and the date of the final order (approximately 189 days).

Because the data covers several economic cycles, the analysis is helpful in assessing the change in the equity risk premium over time. Prior research, for example, has shown that the equity risk premium is inversely related to the level of bond yields.[47]

Q. HOW DO YOU ANALYZE THE RELATIONSHIP BETWEEN BOND YIELDS AND THE EQUITY RISK PREMIUM?

A. I estimate the relationship between bond yields and the equity risk premium by applying a regression analysis, in which the equity risk premium described above is the dependent variable, and the 30-year Treasury yield is the independent variable. To account for the variability in bond yields and authorized ROEs over several decades, I use the semi-log regression, in which the equity risk premium is expressed as a function of the natural log of the 30-year Treasury yield:

$$RP = \alpha + \beta\ (\mathrm{LN}(T_{30}))\quad [6]$$

where:

RP = the equity risk premium;

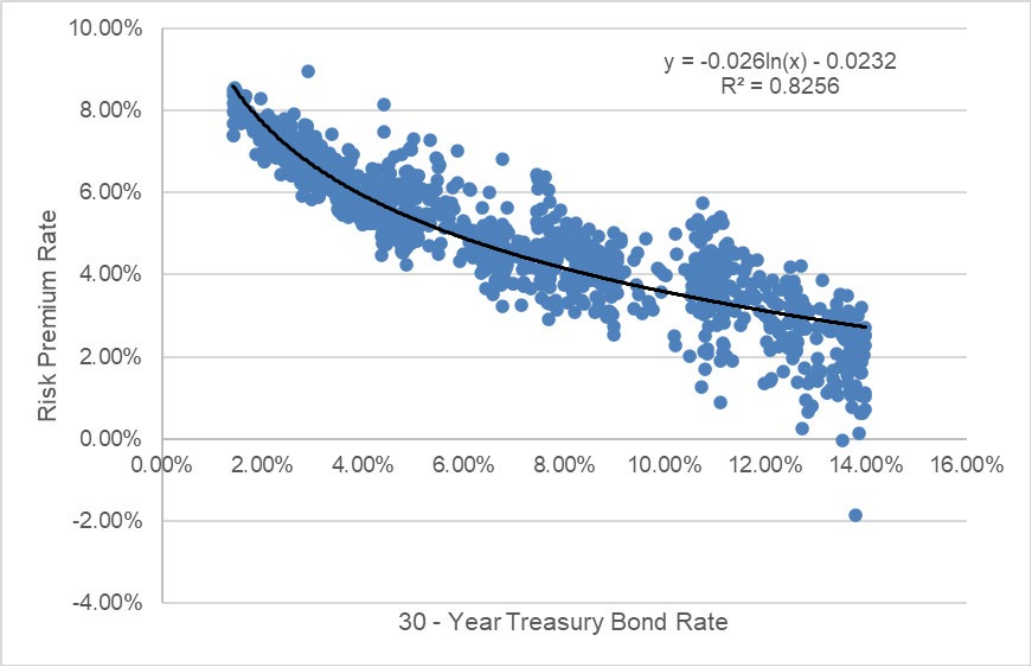
T_{30} = the lagged 30-year Treasury bond yield;

α = the constant term of the regression; and

β = the slope coefficient of the regression.

[47] *See*, *e.g.,* Robert S. Harris and Felicia C. Marston, *Estimating Shareholder Risk Premia Using Analysts' Growth Forecasts*, Financial Management at 63-70 (Summer 1992); Eugene F. Brigham, Dilip K. Shome, and Steve R. Vinson, *The Risk Premium Approach to Measuring a Utility's Cost of Equity*, Financial Management at 33-45 (Spring 1985); and Farris M. Maddox, Donna T. Pippert, and Rodney N. Sullivan, *An Empirical Study of Ex Ante Risk Premiums for the Electric Utility Industry*, Financial Management at 89-95 (Autumn 1995).

Figure 13: Equity Risk Premium[48]



As Figure 13 illustrates, the equity risk premium increases as interest rates fall. The finding that the equity risk premium and interest rates are inversely related is supported by published research. For example, Dr. Morin notes that: "… [p]ublished studies by Brigham, Shome, and Vinson (1985), Harris (1986), Harris and Marston (1992, 1993), Carleton, Chambers, and Lakonishok (1983), Morin (2005), McShane (2005), and others demonstrate that, beginning in 1980, risk premiums varied inversely with the level of interest rates – rising when rates fell and declining when interest rates rose."[49] Based on the regression coefficients in Figure 13, the implied ROE is between 10.21 percent and 10.28 percent (*see* Figure 14 and Exhibit JEN-6).

[48] Exhibit JEN-6.
[49] Roger A: Morin, Ph.D., New Regulatory Finance, Public Utilities Reports, Inc., 2006, at 128 (clarification added).

Figure 14: Summary of Risk Premium Results[50]

	Bond Yield	Risk Premium	Return on Equity
Current 30-Year Treasury	4.83%	5.45%	10.28%
Projected 30-Year Treasury	4.68%	5.53%	10.21%

Q. DO INVESTORS USE A REGRESSION-BASED APPROACH SIMILAR TO YOUR RISK PREMIUM METHOD?

A. Yes, they do. As an example, in a December 2023 report from UBS on the utility sector, the investment bank presented a regression analysis showing that then-current authorized ROEs were below what would be expected given the level of the 10-year Treasury bond yield – *i.e.*, the premise of my Risk Premium analysis.[51]

Q. WHAT ARE THE ADVANTAGES OF THE RISK PREMIUM APPROACH?

A. There are several advantages. First, authorized ROEs in other jurisdictions are a significant part of the market information that investors consider when evaluating their investment alternatives. Therefore, they are a direct measure of returns available to other natural gas utilities, as required under the comparable return standard of the Hope and Bluefield decisions. The authorized ROE also provides a signal to investors about the degree of regulatory support that a company can expect with regard to its ability to compete for capital and to ensure its financial integrity. An ROE below its peers for a given period may be an impediment to the Company's ability to attract capital and finance the infrastructure required to provide safe, reliable service to its customers.

[50] Exhibit JEN-6.
[51] UBS, "US Utilities 2024 Outlook: A Year for Resolutions and Resolve," at 10 (December 12, 2023).

Second, the use of the Risk Premium model in conjunction with the DCF and CAPM approaches adds diversity to the model results, which enables a more robust and reliable ROE estimate. The fewer models that are relied upon, the more likely it is that model risk biases the ultimate ROE determination. For the same reasons that diversity is a wise and prudent investment strategy, diversity of the models used to estimate the ROE is similarly prudent, as it reduces the risk that the results of any single model may not reasonably reflect investors' return requirements.

A third advantage of the Risk Premium approach is its simplicity and reliance on fewer contentious inputs. The Risk Premium approach adds a measure of stability because it is less vulnerable to changes in market data. As shown in the regression equation in Figure 13, the change in the risk premium (and therefore the ROE estimate) as a result of a change in bond yields is less than one-to-one. For example, as shown in Figure 14 above, a 15-basis point increase in the bond yield (from 4.68 percent to 4.83 percent) results in an seven-basis point change in the ROE from 10.21 percent to 10.28 percent.

IV. BUSINESS RISKS AND OTHER CONSIDERATIONS

Q. ARE THERE FACTORS SPECIFIC TO PEOPLES' RISK PROFILE THAT YOU ALSO CONSIDERED IN DEVELOPING YOUR ROE RECOMMENDATION?

A. Yes, there are several factors that have a direct bearing on Peoples' risk profile in relation to the proxy group. Those risk factors include: (a) the Company's substantial capital expenditure program; (b) threat of bypass; (c) regulatory risk relative to the proxy group companies; and (d) flotation costs associated with issuing debt. In aggregate, those risk factors elevate Peoples' risk profile relative to the proxy group and would support an authorized ROE above the midpoint, but I have not made an explicit adjustment.

A. Capital Expenditure Plan

Q. PLEASE DISCUSS PEOPLES' CAPITAL EXPENDITURE PROGRAM.

A. Peoples plans a major capital investment program over the 2026-2030 period, driven mainly by its PUC-approved Long-Term Infrastructure Improvement Plan ("LTIIP"), totaling nearly $4.0 billion. Recognizing customers' focus on safety and reliability as top priorities, the Company's investments are intended to improve the reliability and resiliency. Peoples' significant investments are largely focused on replacement of bare steel and cast/wrought iron pipes pursuant to its LTIIP, which began in 2014 in an effort to replace aging, unsafe gas pipelines.

Q. HOW IS PEOPLES' RISK PROFILE AFFECTED BY ITS CAPITAL EXPENDITURE REQUIREMENTS?

A. As with any utility facing substantial capital expenditure requirements, the Company's risk profile is affected in two significant and related ways: (1) the heightened level of investment increases the risk of under recovery or delayed recovery of the invested capital; and (2) an inadequate return would put downward pressure on key credit metrics. The Company's adjustment clauses should help mitigate the first risk, but only to the extent the allowed return is compensatory. The absolute level of investment required will put significant pressure on the Company's ability to raise capital, and the terms will have lasting impacts for the Company's customers.

Q. DO CREDIT RATING AGENCIES RECOGNIZE THE RISKS ASSOCIATED WITH ELEVATED LEVELS OF CAPITAL EXPENDITURES?

A. Yes. From a credit perspective, the additional pressure on cash flows associated with higher levels of capital expenditures exerts corresponding pressure on credit metrics and, therefore, credit ratings. To that point, S&P explains the importance of regulatory support for large capital projects:

> When applicable, a jurisdiction's willingness to support large capital projects with cash during construction is an important aspect of our analysis. This is especially true when the project represents a major addition to rate base and entails long lead times and technological risks that make it susceptible to construction delays. Broad support for all capital spending is the most credit-sustaining. Support for only specific types of capital spending, such as specific environmental projects or system integrity plans, is less so, but still favorable for creditors. Allowance of a cash return on construction work-in-progress or similar ratemaking methods historically were extraordinary measures for use in unusual circumstances, but when construction costs are rising, cash flow support could be crucial to maintain credit quality through the spending program. Even more favorable are those jurisdictions that present an opportunity for a higher return on capital projects as an incentive to investors.[52]

Moody's also notes that growing power demand, the need to improve grid resilience, and advancing efforts to reduce carbon emissions is increasing capital expenditure pressure for utilities, widening cash flow deficits and weakening their financial strength:

> Credit pressure is emerging most acutely for companies with large, complete or multiyear projects or for those that are experiencing a delay in the recovery of investment costs. Unlike exogenous events of recent year – such as severe storms, commodity price spikes and the COVID-19 pandemic, which we viewed as temporary events – capital spending and related financings are core long-term financial policy issues.[53]

[52] S&P Global Ratings, *Assessing U.S. Investor-Owned Utility Regulatory Environments*, at 7 (August 10, 2016).
[53] Moody's Ratings, *High capital spending will weigh on credit quality without supportive company actions*, at 2 (October 21, 2024).

With regard to PNG Companies LLC, intermediate holding company of Peoples, Moody's notes:

> In addition to the pressured credit metrics, the negative outlook on PNG reflects the lack of any immediate plans to significantly decrease leverage, the utility's elevated capital expenditure plan, and the potential that financial metrics will decline further, with CFO pre-WC to debt possibly falling into the single digits.[54]

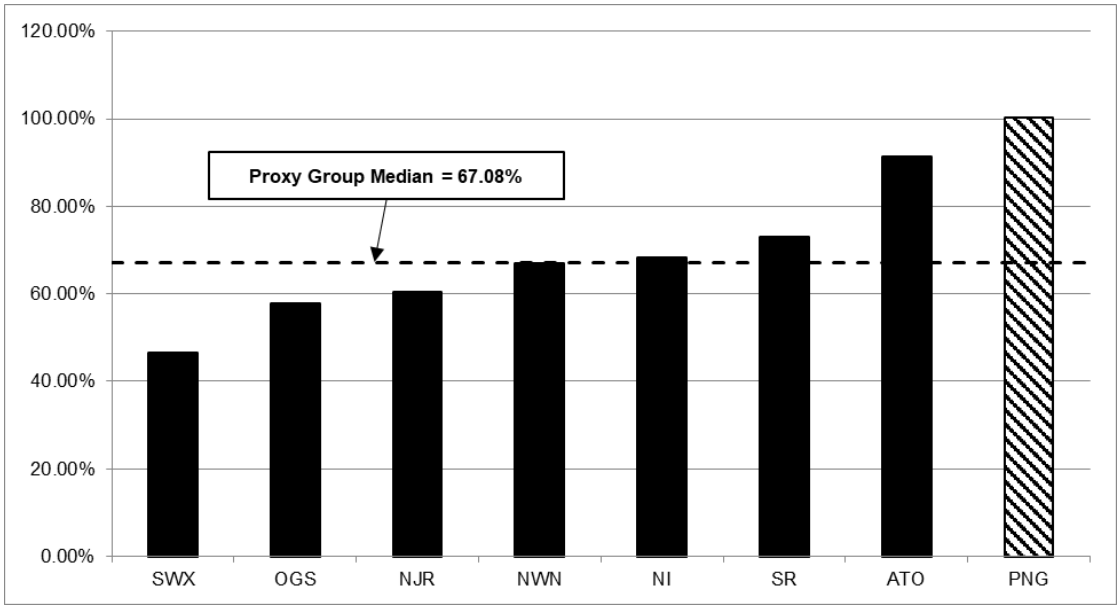
To the extent that Peoples' rates do not permit the Company an opportunity to recover its full cost of doing business, Peoples will face increased recovery risk and thus continued pressure on its credit metrics. Maintaining access to capital markets on reasonable terms is especially important for utilities and their customers, during periods of significant capital investment.

Q. HAVE YOU ANALYZED HOW PEOPLES' CAPITAL SPENDING PROGRAM COMPARES TO THOSE OF THE PROXY GROUP COMPANIES?

A. Yes. I compared the ratio of projected capital expenditures to net utility plant for Peoples to the ratios for the proxy group companies. Figure 15 demonstrates that Peoples' ratio of projected capital expenditures to net utility plant is higher than all of the proxy group companies and is 1.49 times higher than the median ratio for the proxy group of 67.08 percent (*see also* Exhibit JEN-7).

[54] Moody's Ratings, *PNG Companies LLC: Credit Opinion*, at 1 (August 27, 2025).

Figure 15: Ratio of 2026-2030 Capital Expenditures to 2024 Net Utility Plant[55]



Q. WHAT IS YOUR CONCLUSION REGARDING PEOPLES' PROJECTED CAPITAL EXPENDITURE PROGRAM AND THE EFFECT ON THE COMPANY'S RISK PROFILE AND COST OF EQUITY?

A. My primary conclusion is that Peoples has extensive capital investment needs through 2030 that will require the Company to maintain access to capital markets on reasonable terms and conditions. Peoples' ratio of capital expenditure requirements to net utility plant is well above the ratios for the proxy group companies, and the absolute magnitude of Peoples' capital program places pressure on the Company's cash flows and credit metrics. These investments elevate the risk profile of Peoples. For these reasons, it is important that the authorized ROE be set at a level that allows Peoples to continue to attract both debt and equity under favorable terms under a variety of economic and financial market conditions.

[55] Exhibit JEN-7.

B. Risk of Bypass

Q. WHAT IS BYPASS RISK?

A. "Bypass risk" refers to the risk that certain large-volume commercial and industrial customers may reduce its reliance on the Company's distribution service – or bypass it altogether – by arranging an alternative means of procuring natural gas service. This can include (1) physical bypass, such as a direct connection to an interstate pipeline or other upstream facility, or (2) economic bypass, such as shifting away from natural gas distribution service through fuel switching or materially reducing throughput when alternative supply and fuel options are available. Moreover, Peoples' overlapping service territory with Columbia Gas of Pennsylvania in areas surrounding Pittsburgh creates bypass-like incentives for large customers. The alternative fuel competition in Western Pennsylvania is particularly unique relative to monopoly service for other gas utilities (including gas on gas with other natural gas distribution companies, interstate pipeline bypass, and other alternative fuels). Approximately 12 of the Company's customers that represent 20 percent of total throughput (approximately 26.6 billion cubic feet),[56] have the ability to bypass the Company's system.

Q. HOW IS PEOPLES' RISK PROFILE AFFECTED BY THE COMPETITIVE THREAT OF BYPASS?

A. Bypass risk affects Peoples' financial risk primarily through:

- Throughput loss: Large customers contribute significant volumes; losing them can materially reduce throughput, and therefore revenues, cash flow, and earnings.

[56] Company provided data.

- Fixed-cost recovery pressure: Distribution systems are largely fixed-cost in the short to medium term. If large throughput declines, the remaining customer base may bear a larger share of fixed costs.

- Revenue and margin volatility: Unanticipated loss of sales volume can affect revenue timing and recovery between rate proceedings.

- Credit impacts: A material or sustained loss of large-load sales volume can adversely affect cash flow metrics and credit quality.

In summary, loss of large-load throughput can increase earnings and cash flow volatility and elevate the Company's risk relative to fully captive gas distribution utility peers.

C. Regulatory Environment

Q. HOW DOES THE REGULATORY ENVIRONMENT IN WHICH A UTILITY OPERATES AFFECT ITS COST OF CAPITAL?

A. The regulatory environment is one of the most important factors investors consider when assessing a utility's risk, as it is a significant driver of earnings and cash flow that are of utmost importance to investors.[57] Investors and rating agencies understand that a constructive regulatory environment is critical to utilities' credit and financial integrity, especially during stressed market conditions. In fact, 50 percent of the factors that weigh in Moody's ratings determinations relate to the nature of regulation.[58] Predictability and consistency of regulatory actions are crucial factors considered by Moody's in assessing the regulatory framework:

> As the revenues set by the regulator are a primary component of a utility's

[57] Moody's Ratings, *Rating Methodology, Regulated Electric and Gas Utilities*, at 8-11 (August 6, 2024).
[58] Moody's Ratings, *Rating Methodology, Regulated Electric and Gas Utilities*, at 2 (August 6, 2024).

> cash flow, the utility's ability to obtain predictable and supportive treatment within its regulatory framework is one of the most significant factors in assessing a utility's credit quality.
>
> ***
>
> In situations where the regulatory framework is less supportive, or is more contentious, a utility's credit quality can deteriorate rapidly.[59]

Similarly, S&P states that regulatory advantage is "of critical importance" because "[i]t defines the environment in which a utility operates and has a significant bearing on a utility's financial performance."[60] S&P explains that it considers four subfactors when assessing a utility's ability to recover all its costs "on time and in full – and to earn a return on the capital it deploys."[61] Those four subfactors are (1) regulatory stability, (2) tariff-setting procedures and design, (3) financial stability, and (4) regulatory independence and insulation.[62] With respect to capital expenditures, S&P notes that a regulatory "framework's ability to attract long-term capital, and the availability of capital support during construction," support a utility's financial stability as they "alleviate funding and cash flow pressure when heavy investment is needed."[63] Thus, predictability and consistency of regulatory actions are among the primary concerns for the rating agencies, as is full and timely cost recovery, including recovery of capital costs.

Consequently, a utility that operates in a less predictable and more challenging regulatory environment is likely to be viewed as a riskier investment, and may result in lower credit ratings, constrained access to capital (particularly in volatile and adverse market

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59 Moody's Investors Service, *Regulatory Frameworks – Ratings and Credit Quality for Investor-Owned Utilities*, at 2 (June 18, 2010).
60 S&P Global Ratings, *Sector-Specific Corporate Methodology*, Section 29 Regulated Utilities, at 147 (April 4, 2024).
61 *Id*.
62 *Id*.
63 *Id*.

environments), and higher costs of both debt and equity, all else equal. To meet the obligation to serve, it is in customers' best interests to ensure that a utility has efficient access to capital on reasonable terms in all market environments.

Q. HOW DO THE CREDIT RATING AGENCIES VIEW THE REGULATORY ENVIRONMENT IN WHICH THE COMPANY OPERATES?

A. The rating agencies view Pennsylvania as a credit supportive regulatory environment and the current credit ratings of Peoples' immediate parent, PNG Companies LLC, depend on the continued stability and predictability of Pennsylvania's regulatory environment. S&P explains that "PNG's low-risk gas distribution operations in Pennsylvania operate under a credit-supportive regulatory environment. We expect PNG will continue to benefit from the credit-supportive regulatory environment through the use of various regulatory mechanisms, including forward-looking test years and the distribution-system improvement charge mechanism (DSIC)."[64]

Q. HAVE YOU COMPARED PEOPLES' REGULATORY RISK, INCLUDING THE EFFECT OF ITS RATE STRUCTURES, RELATIVE TO THE GAS UTILITIES WITHIN THE PROXY GROUP?

A. Yes, I have. The regulatory environment significantly affects both the access to and the cost of capital. Regulatory decisions regarding the authorized ROE and capital structure directly affect the subject utility's internal cash flow generation, and therefore the financial metrics reviewed by ratings agencies in their ratings assessments. Because credit ratings are intended to reflect the ability to meet financial obligations as they come due, the ability to generate the cash flows

[64] S&P Global Ratings, *PNG Cos. LLC*, October 1, 2025, at 1.

required to meet those obligations (and to provide a cushion for unexpected events) is of critical importance to both debt and equity investors.

To assess the regulatory environment of the proxy companies and Peoples, I reviewed the key cost recovery mechanisms and ratemaking frameworks for each of the natural gas operating companies within the proxy group in the jurisdictions in which they operate, including the cost recovery and volumetric risk mitigation mechanisms in place, test year, and rate base methodology.

As shown in Exhibit JEN-8, like Peoples, all the proxy group operating companies with a retail supply obligation have a purchased gas cost recovery mechanism, 96 percent have a full or partial decoupling mechanism that mitigate volumetric risk, 71 percent have a mechanism to recover energy efficiency program costs, and 96 percent have a mechanism that provides timely recovery of capital costs. Further, 57 percent of the jurisdictions in which proxy group companies operate permit a full or partial forecast test year like the Company.

On balance, from an investor perspective, the regulatory mechanisms available to the Company do not offer a level of risk mitigation that is meaningfully different from the proxy companies. Furthermore, these regulatory mechanisms are only as effective as their implementation, including a compensatory return. It is in customers' best interest that the regulatory environment in Pennsylvania be viewed as predictable, balanced, and supportive of utility investment.

Q. DO THE COMPANY'S REGULATORY MECHANISMS, INCLUDING ITS WEATHER NORMALIZATION ADJUSTMENT CLAUSE AND DSIC, REDUCE ITS RISK RELATIVE TO THE PROXY GROUP?

A. No, they do not. The Company employs cost recovery mechanisms similar to those used by the proxy group; consequently, its risk relative to the proxy group is not reduced because of its rate structures. Further, because the proxy companies all have similar mechanisms, any effects on the cost of equity associated with the rate mechanisms are implicitly captured in the analytical model results.

It is important to remember that risk assessment is a comparative exercise. Rate adjustment mechanisms are common in the utility industry, and the financial community is fully aware of their prevalence. In fact, rate adjustment mechanisms have become more common in the utility industry, not less. As noted earlier, the proxy companies all have similar mechanisms available to them. While the specific details of the mechanics of the rate adjustment mechanisms may differ from utility to utility and jurisdiction to jurisdiction, their objective is the same: to improve the timeliness of cost recovery and mitigate (but not necessarily eliminate) earnings erosion associated with regulatory lag. Because the proxy companies all have mechanisms that improve the timeliness of cost recovery, the Company's regulatory mechanisms simply render it comparable to its peers.

Q. WHAT ARE YOUR CONCLUSIONS REGARDING THE EFFECT OF THE COMPANY'S CAPITAL EXPENDITURE PLANS, ITS NEED TO MAINTAIN

ACCESS TO CAPITAL, AND THE REGULATORY ENVIRONMENT ON ITS RISK PROFILE?

A. The Company's capital expenditure program reflects a significant increase of its net plant in service and increases pressure on its cash flows, making regulatory support critical to Peoples' ability to finance and earn a reasonable return on its planned utility investments. The Company's capital expenditure plan emphasizes the importance of the Commission's decision in this proceeding, which will have a direct bearing on the Company's ability to maintain its financial profile and its access to the capital market at reasonable costs and terms.

The Company will need to rely on external sources of capital to fund critical generation and distribution investments to meet Peoples' significant distribution system requirements. In order to maintain access to external capital at reasonable costs and terms for customers in all market environments, the Company must have a reasonable opportunity to recover its full cost of service, including timely cost recovery of its capital investments and a competitive and compensatory return.

D. Flotation Costs

Q. WHAT ARE FLOTATION COSTS?

A. Flotation costs are the costs associated with the sale of new issues of common stock. These costs include out-of-pocket expenditures for preparation, filing, underwriting, and other costs of issuance of common stock. To the extent that a company is denied the opportunity to recover prudently incurred flotation costs, actual returns will fall short of expected (or required) returns, thereby diminishing the utility's ability to attract adequate capital on reasonable terms. To estimate flotation costs, the DCF calculation is modified to provide a dividend yield that reimburses investors for issuance costs. Based on the proxy group actual issuance costs shown

in Exhibit JEN-9, flotation costs for the proxy companies have equaled roughly 2.62 percent of gross equity raised. To properly reflect these issuance costs in my cost of capital estimates, it would be necessary to increase the authorized ROE by nine basis points for Peoples, as quantified in Exhibit JEN-9.

Q. DO ACADEMIC AND FINANCIAL EXPERTS RECOGNIZE THE NEED TO CONSIDER FLOTATION COSTS IN A UTILITY'S COST OF EQUITY?

A. Yes. Dr. Morin summarizes:

> The costs of issuing these securities are just as real as operating and maintenance expenses or costs incurred to build utility plants, and fair regulatory treatment must permit recovery of these costs…. The simple fact of the matter is that common equity capital is not free…. [Flotation costs] must be recovered through a rate of return adjustment. [65]

> According to Dr. Shannon Pratt, a published expert in cost of capital estimation:

> Flotation costs occur when new issues of stock or debt are sold to the public. The firm usually incurs several kinds of flotation or transaction costs, which reduce the actual proceeds received by the firm. Some of these are direct out-of-pocket outlays, such as fees paid to underwriters, legal expenses, and prospectus preparation costs. Because of this reduction in proceeds, the firm's required returns on these proceeds equate to a higher return to compensate for the additional costs. Flotation costs can be accounted for either by amortizing the cost, thus reducing the cash flow to discount, or by incorporating the cost into the cost of capital. Because flotation costs are not typically applied to operating cash flow, one must incorporate them into the cost of capital.[66]

Q. ARE FLOTATION COSTS PART OF THE UTILITY'S INVESTED COSTS OR EXPENSES?

A. Flotation costs are invested (*i.e.*, capital) costs of the utility and are reflected on the balance sheet under "paid in capital." Flotation costs are not expenses and are not included on the

[65] Roger A. Morin, New Regulatory Finance (Public Utility Reports, Inc., 2006), at 321.
[66] Shannon P. Pratt, Cost of Capital Estimation and Applications, Second Edition, at 220-221.

income statement. Like rate base or long-term debt issuance costs, flotation costs are incurred over time. Although much of a utility's flotation costs are incurred prior to the test year, they remain part of the cost structure long after they are incurred. As such, recovery of equity issuance costs is appropriate for the same reasons debt issuance costs are recoverable. Even if no new issuances are planned in the near future, failure to allow such cost recovery may deny Peoples the opportunity to earn its required rate of return going forward.

Q. DO THE DCF, CAPM, AND RISK PREMIUM MODELS ACCOUNT FOR THE EFFECT OF FLOTATION COSTS?

A. No. The models used to estimate the investor-required return assume no transaction costs (*i.e.*, "friction"); therefore, flotation costs are not reflected in stock prices or the risk premium.

Q. DO YOU MAKE AN EXPLICIT ADJUSTMENT TO YOUR ROE RECOMMENDATION FOR FLOTATION COST RECOVERY?

A. No, I do not. While appropriate to do so, in this case, I have conservatively not made an explicit adjustment to my ROE recommendation for flotation cost recovery.

V. CAPITAL STRUCTURE AND COST OF LONG-TERM DEBT

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

A. As shown in Exhibit JEN-10, the Company's FPFTY capital structure consists of 54.47 percent common equity and 45.53 percent long-term debt.

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

A. A company's total risk consists of business risk and financial risk. Business risk includes operating, market, regulatory, and competitive uncertainties, while financial risk is the incremental risk to investors associated with additional leverage, or levels of debt. Therefore,

the capital structure indicates a company's financial risk, which reflects the risk that a company may not have adequate cash flows to meet its financial obligations.

As the percentage of debt in the capital structure increases, so do the fixed obligations for the repayment of that debt and the risk of financial distress.[67] In essence, even if two firms face the same business risks, a company with meaningfully higher levels of debt in its capital structure is riskier, which increases its costs of both debt and equity.

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

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

Q. WHAT ARE THE GUIDELINES FOR DETERMINING WHETHER A UTILITY'S CAPITAL STRUCTURE IS WITHIN INDUSTRY STANDARDS?

A. In a 2020 publication titled *A Cost of Capital and Capital Markets Primer for Utility Regulators*, the National Association of Regulatory Utility Commissioners ("NARUC") states that actual capital structure ratios should be used unless they "greatly diverge" from sound industry practice:

> A utility management must be permitted latitude, discretion, and flexibility in managing capital structure ratios. Since there is no practical methodology to pinpoint theoretically optimal capital structure ratios, targeted ratios can only be broadly conceptualized. Appropriate ratios may shift over time as capital

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

> market conditions or business risk characteristics change. Additionally, the timing of upcoming issuances and maturities may influence the capital structure ratios because both the size and frequency of issuances are affected by the relative cost-effectiveness of various issuance increments.
>
> Given these practical considerations, capital structure ratios cannot be deemed to be inappropriate unless the ratios greatly diverge from sound industry practice and cause a lack of financial flexibility that may lead to higher overall costs.
>
> ***
>
> As increasing financial leverage shifts the weight from common equity to lower cost debt, it also increases both the cost of debt and the cost of common equity. In practice, these offsetting impacts cancel each other out over a wide range of capital structure ratios".[68]

Further, James C. Bonbright explains in his seminal text Principles of Public Utility Rates that a hypothetical capital structure should be used only when actual capital structures are "clearly unsound" or "extravagantly conservative," reasoning that using hypothetical capital structures "substitutes an estimate of what the capital cost would be under non-existing conditions for what it actually is or will soon be under prevailing conditions."[69]

Q. HAVE YOU ASSESSED WHETHER PEOPLES' CAPITAL STRUCTURE IS CONSISTENT WITH SOUND INDUSTRY PRACTICE?

A. Yes, I have. To make that assessment, I calculated the average capital structure for each of the proxy group operating companies over the last three years (*see,* Exhibit JEN-11). On average, the proxy group operating companies finance their regulated natural gas distribution operations with 54.26 percent common equity (and a median of 54.83 percent), within a range of 46.51 percent to 60.16 percent.[70] From that perspective, Peoples' proposed capital structure is consistent with its peers.

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[68] NARUC, *A Cost of Capital and Capital Markets Primer for Utility Regulators* (April 2020), at 11 (emphasis added).
[69] James C. Bonbright, Principles of Public Utility Rates, at 243-44.
[70] Exhibit JEN-11.

Q. WHY DO YOU COMPARE PEOPLES' PROPOSED CAPITAL STRUCTURE TO THE PROXY GROUP OPERATING COMPANIES, RATHER THAN THE PROXY GROUP CONSOLIDATED HOLDING COMPANIES?

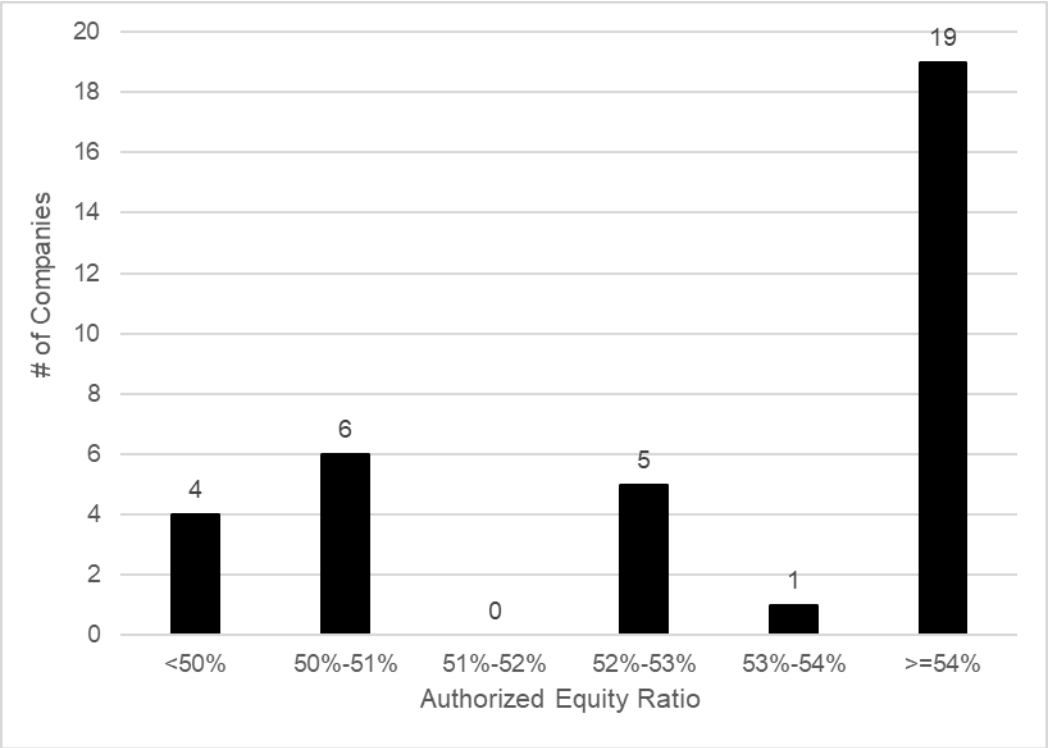
A. The capital structure at the consolidated holding company level does not influence the capital structure of the operating subsidiaries, as operating subsidiaries are financed according to the unique risks and financing needs of each subsidiary. Holding companies do not have the obligation to serve like regulated operating subsidiaries do. Because of the obligation to serve, operating subsidiaries must maintain financial flexibility and access to capital under a variety of operating and capital market environments and constraints. Thus, operating subsidiaries require more equity in the capital structure than their consolidated parent holding companies.

Comparisons to the consolidated holding company capital structures simply do not reflect the common financing constraints faced by operating subsidiaries with the obligation to serve. The only apples-to-apples comparison to discern the appropriate capitalization for a regulated operating utility is a comparison to other regulated operating utility subsidiaries.

Q. IS A CAPITAL STRUCTURE CONSISTING OF 54.47 PERCENT COMMON EQUITY CONSISTENT WITH AUTHORIZED EQUITY RATIOS FOR THE PROXY GROUP?

A. Yes. As shown in Exhibit JEN-12, an equity ratio of 54.47 percent is close to the average and median current authorized equity ratios for the proxy companies in the jurisdictions in which they operate (54.72 percent and 54.40 percent, respectively). Additionally, approximately 54 percent of the proxy group companies have an authorized equity ratio equal to or greater than 54.00 percent in the jurisdictions in which they operate (*see*, Figure 16).

Figure 16: Distribution of Proxy Group Current Authorized Equity Ratios[71]



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

A. The requested common equity ratio of 54.47 percent is within the range of actual and authorized equity ratios for its peers and is, therefore, consistent with industry standards. As such, a capital structure including 54.47 percent common equity and 45.53 percent long-term debt is reasonable and should be approved.

Q. WHAT IS THE REQUESTED COST OF LONG-TERM DEBT IN THIS PROCEEDING?

A. The cost of debt reflects the interest rate payable on Peoples' long-term debt. The cost of debt is calculated as the weighted average interest rate of the Company's existing long-term

[71] Exhibit JEN-12.

debt outstanding, including any discount or premium and issuance expenses. As shown in Exhibit JEN-13, the Company's embedded cost of long-term debt is 4.02 percent as of November 30, 2025, 4.31 percent as of November 30, 2026; and 4.61 percent for the FPFTY.

Q. HOW DID YOU DETERMINE THE PROJECTED YIELDS FOR PEOPLES' ANTICIPATED DEBT ISSUANCES IN 2026 AND 2027?

A. Since there are no publicly available forecasts of utility bond yields that I am aware of, I estimated the projected yields on 12-year bonds for Peoples using the 2026 and 2027 projected Corporate BBB bond yield reported by Blue Chip Financial Forecasts less the long-term average spread of 70 basis points between Moody's Corporate BBB bonds and 12-year Utility BBB bonds between January 2000 and February 2026. Figure 17 below summarizes the 2026 and 2027 long-term debt costs estimates.

Figure 17: 2026 and 2027 Peoples' Long-Term Debt Coupon Rates[72]

	Blue Chip Projected BBB Corporate Bond Yield	Lont-Term Average Spread on 12-Year Utility BBB Bond Yields and BBB Corporate Bond Yields	Projected Peoples' Long-Term Debt Coupon Rate
2026	6.03%	-0.7%	5.33%
2027	6.10%	-0.7%	5.40%

The coupon rate for each current and projected debt issuance is then translated into an effective cost rate using the yield to maturity method, as calculated on page 4 of Exhibit JEN-13.

[72] Sources: Blue Chip Financial Forecasts, Vol. 45 No. 3, February 27, 2026 page 2 (2026 forecast); Blue Chip Financial Forecasts, Vol. 44 No. 12, December 1, 2025 page 14 (2027 forecast); Bloomberg Professional.

VI. CAPITAL MARKET ENVIRONMENT

Q. DO ECONOMIC CONDITIONS INFLUENCE THE REQUIRED COST OF CAPITAL, INCLUDING THE ROE?

A. Yes. The required cost of capital, including the ROE, is a function of prevailing and expected economic and capital market conditions. Each of the analytical models used to estimate the required ROE is influenced by current and expected capital market conditions. Therefore, an evaluation of current and projected market conditions is integral to any ROE recommendation.

Q. WHAT ARE THE KEY MACROECONOMIC FACTORS AFFECTING THE COST OF EQUITY FOR REGULATED UTILITIES IN THE CURRENT AND PROSPECTIVE CAPITAL MARKETS?

A. The cost of equity for regulated utilities is currently affected by several key factors, including: (1) the interest rate environment and central bank monetary policy; (2) inflationary pressure and the outlook for inflation and long-term government and utility bond yields; and (3) uncertainty in the economic environment due to geopolitical events. As discussed below, although the Federal Reserve reduced the Federal Funds rate three times in both 2024 and 2025, interest rates and inflation are expected to remain above the levels experienced prior to the COVID-19 pandemic. Further, geopolitical events present uncertainties with respect to the near-term economic and capital market in which the Company will be raising external capital.

Q. HOW HAVE ECONOMIC AND FINANCIAL MARKET CONDITIONS CHANGED IN RECENT MONTHS?

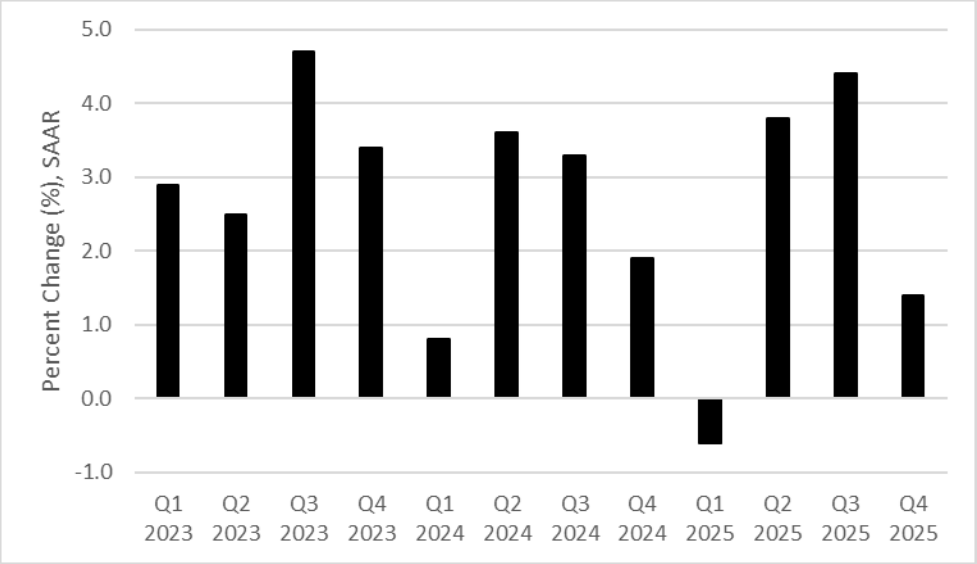
A. At the end of 2024, financial markets were optimistic that the Federal Reserve was close to attaining a "soft landing" by taming inflation without a consequential rise in unemployment. In 2025, however, economic and federal policy uncertainty climbed sharply. As Blue Chip

Financial Forecasts explains, "Numerous Fed officials have noted that there are currently upside risks to the inflation outlook while there are downside risks to the employment outlook, a combination that makes the near-term course for monetary policy very uncertain."[73] Further, in its Outlook 2026 report, J.P. Morgan Private Bank emphasized the structural, rather than temporary, shift in the state of inflation.[74] J.P. Morgan notes that inflation is expected to remain more volatile and prone to upward shocks compared with the pre-pandemic period.[75] Consumer sentiment fell nearly 21 percent between January 2025 and February 2026.[76]

Despite the uncertain economic outlook and weak consumer sentiment, Gross Domestic Product ("GDP") remained resilient. As shown in Figure 18, after posting a decline in the first quarter of 2025, real GDP rose in each of the next three quarters, posting an annual increase of 1.4 percent in the fourth quarter of 2025. This demonstrates that there are mixed signals among the economic indicators.

[73] Blue Chip Financial Forecasts, Vol. 44, No. 12, December 1, 2025, at 1.
[74] J.P. Morgan Private Bank, *2026 Outlook: Promise and Pressure*, at 7.
[75] *Ibid.*
[76] University of Michigan, Survey of Consumers, Index of Consumer Sentiment, https://www.sca.isr.umich.edu/charts.html.

Figure 18: Quarterly Real GDP (Seasonally Adjusted at Annual Rates)[77]



Q. PLEASE DESCRIBE RECENT MONETARY POLICY ACTIONS BY THE FEDERAL RESERVE.

A. At its December 2025 meeting, the Federal Open Market Committee ("FOMC") lowered the target range of the Federal Funds rate by 25 basis points for the third time in 2025 to 3.50 to 3.75 percent. In doing so, the FOMC noted the downside risks to employment on the one hand but that "[i]nflation has moved up since earlier in the year and remains somewhat elevated."[78] The FOMC maintained its federal funds rate target range at its January 2026 meeting, noting that inflation remains "somewhat elevated" and uncertainty about the economic outlook remains "elevated."[79]

[77] Source: U.S. Bureau of Economic Analysis.
[78] Federal Reserve FOMC Press Release, December 10, 2025, https://www.federalreserve.gov/newsevents/pressreleases/monetary20251210a.htm.
[79] Federal Reserve FOMC Press Release, January 28, 2026, https://www.federalreserve.gov/newsevents/pressreleases/monetary20260128a.htm.

Q. DO THE FEDERAL RESERVE'S RECENT CUTS TO THE FEDERAL FUNDS RATE MEAN THAT LONG-TERM GOVERNMENT AND UTILITY BOND YIELDS WILL AUTOMATICALLY FOLLOW?

A. Not necessarily. Long-term bond yields – like the 30-year Treasury yield that is applied in the ROE models and used as a benchmark for long-term utility debt – are less sensitive to the Federal Reserve's monetary policy. Long-term interest rates are influenced by the demand and supply for long-term bonds, inflation expectations, fiscal policy, and federal debt levels. As explained in more detail below, consumers' long-term inflation expectations remain elevated and fiscal policy has become more uncertain; thus, long-term government bonds have not declined commensurate with the Federal Reserve's reductions in the Federal Funds rate. As shown in Figure 19 below, since the end of June 2024 (prior to the Fed's first round of rate cuts), the 1-year and 2-year Treasury yields declined by 161 and 119 basis points, respectively, whereas the 30-year Treasury yields *increased* by 36 basis points. Since models used to estimate the just and reasonable ROE rely on long-term yields, the market movement of short-term bond yields does not influence the ROE model results in the way that long-term yields do.

Figure 19: U.S. Treasury Yields (June 2024 vs. January 2026)[80]

	1-year Treasury	2-year Treasury	30-year Treasury
June 28, 2024	5.09%	4.71%	4.51%
January 30, 2026	3.48%	3.52%	4.87%
Change	-1.61%	-1.19%	+0.36%

[80] Source: Federal Reserve Board of Governors, H.15 Selected Interest Rates.

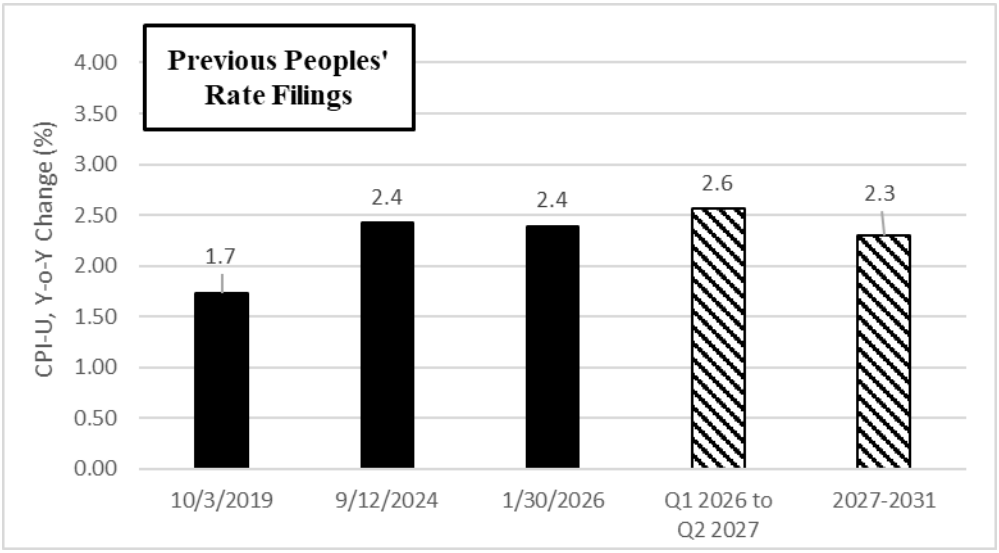
Q. ARE CHANGES IN LONG-TERM BOND YIELDS MORE RELEVANT TO THE COST OF EQUITY FOR UTILITIES THAN SHORT-TERM INTEREST RATES?

A. Yes. The 30-year Treasury bond yield is a direct input to both the CAPM and Risk Premium models because the term of the bond aligns with the long life of electric utility assets. As long-term bond yields increase, the cost of capital generally increases, and the ROE estimates from those two models also increase, although not on a one-to-one basis. While interest rates are not a direct input to the DCF model, dividend yields on utility stocks must compete with yields on Treasury bonds. As interest rates on government bonds increase, utilities must offer a higher dividend yield to attract and retain investors, signaling an increase in the cost of equity for utilities. All else equal, higher dividend yields produce higher ROE estimates in the DCF model.

Q. WHAT ARE THE EXPECTATIONS FOR INFLATION AND LONG-TERM GOVERNMENT AND UTILITY BOND YIELDS IN THE NEAR TERM?

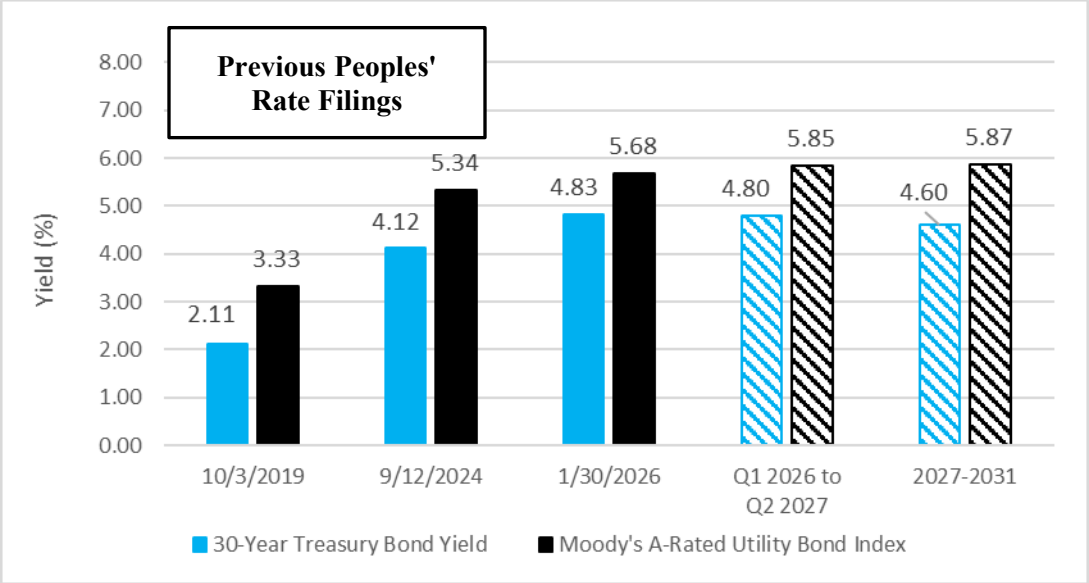
A. Both inflation and long-term government and utility bond yields are expected to remain above their pre-pandemic levels. As shown in Figure 20 and Figure 21 below, inflation and long-term government and utility bond yields have been higher than the levels experienced in 2019 prior to the COVID-19 pandemic and are expected to remain elevated and near current levels over the next five years.

Figure 20: Consumer Price Index (2019 and 2024 vs. 2026 and Forecasted)[81]



[81] Sources: Federal Reserve Bank of St. Louis, FRED Economic Database, series CPIAUCSL, https://fred.stlouisfed.org/series/CPIAUCSL; Blue Chip Financial Forecasts, Vol. 45 No. 2, at 2 and Blue Chip Financial Forecasts, Vol. 44, No. 12, at 14.

Figure 21: 30-Year Treasury Yield and Moody's A Rated Utility Bond Index (2019 and 2024 vs. 2026 and Forecasted)[82]



Q. HOW MIGHT PERSISTENT INFLATION AND ELEVATED INTEREST RATES AFFECT THE COST OF EQUITY FOR UTILITIES?

A. Longer-term bonds like the 30-year Treasury bond are more sensitive to inflation expectations than shorter-term bonds because their value is influenced more by inflation due to their longer maturity holding period and reinvestment rate implications. Thus, as the value (price) of bonds declines due to higher inflation expectations, the yield increases. Because utilities are capital intensive enterprises, higher inflation and interest rates tend to have a negative effect on utility stocks. Higher inflation and interest rates lead to increases in the cost of capital for utilities.

[82] Sources: Federal Reserve Bank of St. Louis, FRED Economic Database, series DGS30, https://fred.stlouisfed.org/series/DGS30; Bloomberg Professional; Federal Reserve Bank of St. Louis, FRED Economic Database, series DAAA, https://fred.stlouisfed.org/series/DAAA; Blue Chip Financial Forecasts, Vol. 45 No. 2, at 2 and Blue Chip Financial Forecasts, Vol. 44 No. 12, at 14. Projected Utility "A" bond yields are estimated from Blue Chip's projected AAA corporate bond yields plus the average historical spread between AAA-rated corporate and A-rated utility bond yields over the last five years.

Q. PLEASE DISCUSS THE RECENT CHANGES IN U.S. TRADE POLICY AND GEOPOLITICAL EVENTS.

A. During 2025, the Trump administration announced, implemented, or delayed implementation of tariffs on numerous U.S. trade partners. A highlight of this is when, on April 2, 2025, President Trump announced the administration would impose a 10 percent base tariff on all imports from nearly every country plus an additional "reciprocal" tariff customized for each of approximately 60 countries.[83] These reciprocal tariffs were subsequently paused, but significant uncertainty remains around the future course of U.S. trade policy and how it will affect the economy. More recently, on February 20, 2026, the Supreme Court struck down President Trump's tariffs,[84] though he responded with a pledge to impose a new global 15 percent tariff.[85]

This created significant policy and market uncertainty; as can be seen in Figure 22 below, the Federal Reserve Bank of St. Louis' Economic Policy Uncertainty Index (the "EPU Index") spiked to levels not seen since the COVID-19 pandemic. While the EPU Index has partially subsided in recent months (to 349.75 as of January 2026), it is still significantly above the average over the last eleven years (154.02). This heightened U.S. policy and market uncertainty is further evidenced by the weakened U.S. dollar ("USD"), which depreciated against gold and a broad set of foreign currencies in 2025; from December 31, 2024, to December 31, 2025, the USD depreciated 7.80 percent against the Federal Reserve's trade-weighted USD index, and gold prices (as measured in USD) increased by approximately 65

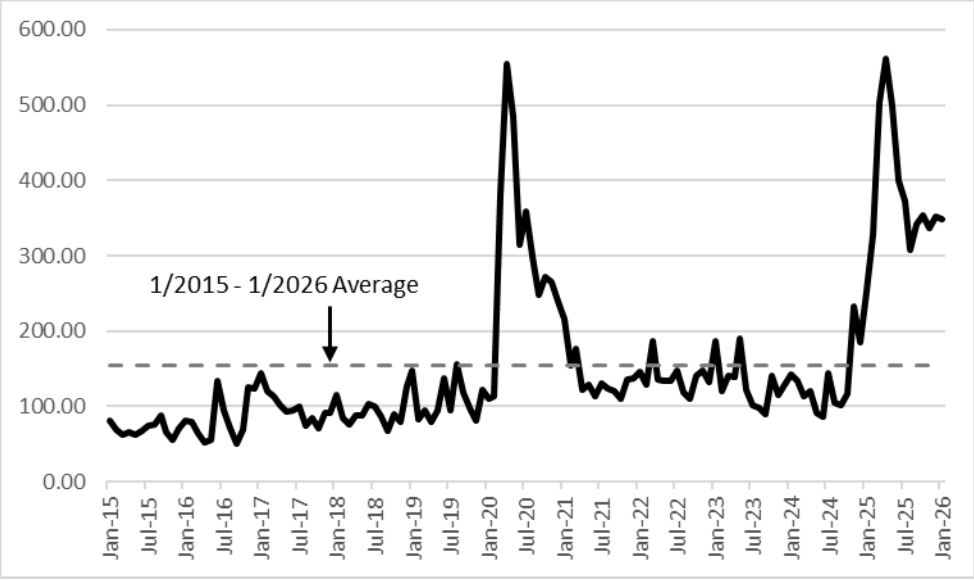
[83] https://www.whitehouse.gov/presidential-actions/2025/04/regulating-imports-with-a-reciprocal-tariff-to-rectify-trade-practices-that-contribute-to-large-and-persistent-annual-united-states-goods-trade-deficits/

[84] https://apnews.com/article/supreme-court-tariffs-trump-0485fcda30a7310501123e4931dba3f9.

[85] https://www.nytimes.com/2026/02/21/business/trump-tariffs.html.

percent.[86] The January 3, 2026 U.S. bombing of Venezuela and subsequent capture of Venezuelan President Maduro,[87] potential criminal investigations into Federal Reserve Board members, including Chair Powell,[88] and the U.S. and Israeli attack on Iran[89] further add to the economic and geopolitical uncertainty. Uncertainty increases risk, which increases the cost of equity, all else equal.

Figure 22: Economic Policy Uncertainty Index January 1, 2015 – January 31, 2026[90]



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

A. My primary conclusion is that the economic and financial market environment is uncertain concerning inflation, the strength of the economy, the outcome of federal trade policy and other

[86] Sources: Federalreserve.gov H10 data; Goldprice.org.

[87] https://www.cbsnews.com/live-updates/venezuela-us-military-strikes-maduro-trump/.

[88] https://abcnews.go.com/Politics/doj-launches-criminal-investigation-fed-chair-jerome-powell/story?id=129114228.

[89] https://www.pbs.org/newshour/world/u-s-and-israel-launch-a-major-attack-on-iran-trump-says-supreme-leader-khamenei-killed.

[90] Source: Federal Reserve Bank of St. Louis, FRED Economic Database, series USEPUINDXD, https://fred.stlouisfed.org/series/USEPUINDXD/.

geopolitical events, and the path of monetary policy. Although the Federal Reserve has cut the level of short-term interest rates, long-term government and utility bond yields have not followed suit and remain elevated relative to the very low-interest rate environment experienced in the prior decade. Lastly, inflation is expected to remain elevated and above pre-pandemic levels. These factors underscore the importance of using multiple models when determining the Company's cost of equity to gain a comprehensive perspective of the effect of fluid and evolving market conditions on the cost of equity.

VII. CONCLUSION

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

A. As discussed throughout my Direct Testimony, it is important to consider a variety of quantitative and qualitative information in reviewing analytical results and arriving at ROE determinations. The results from three commonly used analytical approaches indicate a cost of equity ranging from approximately 10.20 percent to 11.90 percent. Within that range, I recommend a base ROE of 11.00 percent, which is the approximate midpoint of the range of model results. The base ROE recommendation does not include additional adjustments for Peoples' heightened capital expenditures, risk associated with the potential for customers to bypass its system, and flotation costs. Additionally, I support the Company's requests for a 25 basis point premium to reflect its superior management performance.

As to the capital structure, the Company's requested capital structure of 54.47 percent common equity and 45.53 percent long-term debt is within the range of capital structures that finance the regulated utility operations of the proxy group and, therefore, is reasonable and

appropriate and should be approved. I also support the requested cost of long-term debt of 4.61 percent.

Q. DOES THIS COMPLETE YOUR DIRECT TESTIMONY?

A. Yes, it does.

VERIFICATION

I, Jennifer E. Nelson, under penalty of perjury, on this 20th day of March, 2026, declare that the foregoing is true and correct to the best of my knowledge and belief.

/s/ Jennifer E. Nelson

APPENDIX A: SPONSORED STANDARD FILING REQUIREMENTS

Reference	Filing Requirement
Ex. 16, Sch. 1	53.53.II.A.1
Ex. 16, Sch. 2	53.53.II.A.2
Ex. 16, Sch. 3	53.53.II.A.3
Ex. 16, Sch. 4	53.53.II.A.4
Ex. 16, Sch. 5	53.53.II.A.5
Ex. 16, Sch. 6	53.53.II.A.6
Ex. 16, Sch. 7	53.53.II.A.7
Ex. 16, Sch. 9	53.53.II.A.12
Ex. 16, Sch. 10	53.53.II.A.14
Ex. 16, Sch. 11	53.53.II.A.15
Ex. 16, Sch. 12	53.53.II.A.19
Ex. 16, Sch. 13	53.53.II.A.25
Ex. 18, ROR 4	Exhibit VI.IV.ROR.4
Ex. 18, ROR 6	Exhibit VI.IV.ROR.6
Ex. 18, ROR 7	Exhibit VI.IV.ROR.7
Ex. 18, ROR 9	Exhibit VI.IV.ROR.9
Ex. 18, ROR 10	Exhibit VI.IV.ROR.10
Ex. 18, ROR 11	Exhibit VI.IV.ROR.11
Ex. 18, ROR 12	Exhibit VI.IV.ROR.12
Ex. 18, ROR 15	Exhibit VI.IV.ROR.15
Ex. 18, ROR 17	Exhibit VI.IV.ROR.17
Ex. 18, ROR 18	Exhibit VI.IV.ROR.18
Ex. 18, ROR 19	Exhibit VI.IV.ROR.19
Ex. 18, ROR 20	Exhibit VI.IV.ROR.20
Ex. 18, ROR 21	Exhibit VI.IV.ROR.21

JENNIFER E. NELSON
VICE PRESIDENT

Jennifer Nelson is a Certified Rate of Return Analyst with more than 15 years of experience in the energy industry. As an expert witness, she has testified to the cost of capital and alternative ratemaking proposals for electric, natural gas, and water utilities. In her time as a consultant, Ms. Nelson has provided consulting services on a variety of utility regulatory matters including ratemaking and regulatory policy, cost of service and revenue requirements, integrated resource planning, natural gas pipeline development, utility supply planning issues, and merger and acquisition transactions. She also has extensive experience performing statistical analyses, developing economic and financial models, and providing policy analyses and recommendations.

Prior to joining Concentric, Ms. Nelson was a Director at ScottMadden, Inc., and a managing consultant at Sussex Economic Advisors, LLC. Prior to consulting, she was a staff economist at the Massachusetts Department of Public Utilities and a petroleum economist for the State of Alaska. Ms. Nelson holds a Master of Science degree in Resource and Applied Economics from the University of Alaska and a Bachelor of Science degree in Business Economics from Bentley University. Ms. Nelson has been recognized as one of the *Top 25 Women Leaders in Consulting for 2026* by The Consulting Report.

AREAS OF EXPERTISE

Cost of Capital

- Submitted expert testimony on behalf of electric utilities before regulatory commissions in Arkansas, Kansas, Michigan, New Hampshire, New Mexico, North Carolina, Pennsylvania, South Carolina, Texas, and Virginia regarding the cost of capital.
- Submitted expert testimony on behalf of natural gas utilities before regulatory commissions in Alaska, Florida, Michigan, North Carolina, Ohio, Oregon, South Carolina, Utah, West Virginia, and Wyoming regarding the cost of capital.
- Submitted expert testimony on behalf of a water utility before the Kentucky Public Service Commission regarding the appropriate capital structure and cost of debt.
- Supported expert testimony regarding the cost of capital before numerous state utility regulatory commissions and the FERC on behalf of electric and natural gas utilities through research, financial analysis and modeling, and testimony development.

Alternative Ratemaking Mechanisms

- Submitted expert testimony on behalf of electric utilities and a water utility before the Arkansas Public Service Commission regarding the utilities' proposed Formula Rate Plans.
- Submitted expert testimony on behalf of an electric utility before the Oklahoma Corporation Commission regarding the utility's proposed Formula Rate Plan.
- Submitted expert testimony on behalf of an electric and natural gas utility before the Delaware Public Service Commission regarding the utility's proposed performance-based rate plan.

- Submitted expert testimony on behalf of an electric and natural gas utility before the Montana Public Service Commission regarding the utility's proposed alternative rate mechanisms.
- Co-sponsored expert testimony on behalf of a natural gas utility before the Maine Public Utilities Commission regarding the utility's proposed capital investment cost recovery mechanism.
- Supported expert testimony and performed research and analysis on alternative ratemaking frameworks.

Resource and Supply Planning

- Supported expert testimony on the reasonableness of utility resource supply portfolio decisions.
- Assisted in a benchmarking analysis on behalf of a Northeast U.S. natural gas utility regarding its supply planning standards and design day demand forecast process.
- Supported rebuttal testimony filed on behalf of an Alaska natural gas utility regarding the utility's gas supply planning standards.
- Supported the development of a New Hampshire electric utility's Integrated Resource Plan filed with the New Hampshire Public Utility Commission.
- Performed research and financial analysis to evaluate the benefits, costs, and policy options associated with natural gas expansion by Massachusetts natural gas utilities as part of a prepared report for the Massachusetts Department of Energy Resources.
- Developed a dynamic natural gas demand forecast model for in-state use for the State of Alaska, which included forecasting demand from both existing and anticipated natural gas utilities, power consumption, and large commercial operations.
- Conducted research and prepared analyses for a natural gas pipeline Open Season.

Other Regulatory Financial Issues

- Filed expert testimony before the California PUC regarding the benefits of financial flexibility and diversity in sources of financial capital associated with an electric utility's request to lease entitlements as a means of raising capital.
- Supported expert testimony on the appropriate level of remuneration associated with the Massachusetts electric utilities' long-term contracts for wind power through research, financial analysis and modeling, and testimony development.
- Provided research and analytical support estimating financial damages incurred as a result of construction delays for an electric transmission company.
- Prepared a Feasibility Study for an electric cooperative utility supporting a utility-owned solar project.

Mergers & Acquisitions

- Performed buy-side benchmarking and regulatory analysis for utility acquisitions.

RELEVANT PROFESSIONAL HISTORY

Concentric Energy Advisors, Inc. (2021-present)
Vice President
Assistant Vice President

ScottMadden, Inc. (2016-2021)
Director
Manager

Sussex Economic Advisors, LLC (2013-2016)
Managing Consultant

Massachusetts Department of Public Utilities (2011-2013)
Economist, Electric Power Division

State of Alaska Department of Revenue, Tax Division (2007-2010)
Petroleum Economist

Federal Reserve Bank of Boston (2000-2002)
Research Assistant, Economic Research Department

EDUCATION AND RELEVANT COURSEWORK

University of Alaska
Master of Science, Resource and Applied Economics

Bentley University (formerly Bentley College)
Bachelor of Science, Business Economics
Graduated *magna cum laude*

New Mexico State University
Center for Public Utilities, Regulatory Basics

ISO New England
Wholesale Energy Markets (WEM-101)

Colorado School of Mines
Petroleum Engineering SuperSchool

EUCI
Course Instructor – Performance-Based Ratemaking

AWARDS, DESIGNATIONS, AND PROFESSIONAL AFFILIATIONS

Recognized as one of the *Top 25 Women Leaders in Consulting for 2026* by The Consulting Report
Certified Rate of Return Analyst, Society of Utility and Regulatory Financial Analysts
Member, Society of Utility and Regulatory Financial Analysts

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Regulatory Commission of Alaska				
ENSTAR Natural Gas Company	04/25	ENSTAR Natural Gas Company	TA-352-4	Cost of Capital
Arkansas Public Service Commission				
Liberty Utilities (Pine Bluff Water)	10/18	Liberty Utilities (Pine Bluff Water)	18-027-U	Formula Rate Plan and tariff
Entergy Arkansas, LLC	11/20	Entergy Arkansas, LLC	16-036-FR	Evaluated the Return on Equity included in Rider FRP
Oklahoma Gas & Electric	10/21	Oklahoma Gas & Electric	21-087-U	Formula Rate Plan
California Public Utilities Commission				
Pacific Gas & Electric Co.	01/25	Pacific Gas & Electric Co.	A-24-03-009	Financial flexibility and capital diversity
Delaware Public Service Commission				
Delmarva Power & Light Company	08/24	Delmarva Power & Light Company	24-0868	Alternative Ratemaking Proposal
Florida Public Service Commission				
Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	05/22	Pivotal Utility Holdings, Inc. d/b/a Florida City Gas	20220069-GU	Cost of Capital
State Corporation Commission of Kansas				
Evergy Kansas Central and Evergy Kansas South, Inc.	07/25	Evergy Kansas Central and Evergy Kansas South, Inc.	25-EKCE-294-RTS	Capital Structure
The Empire District Electric Company d/b/a Liberty	12/25	The Empire District Electric Company d/b/a Liberty	26-EPDE-0180-RTS	Capital Structure, Cost of Capital and Cost of Debt
Kentucky Public Service Commission				
Bluegrass Water Utility Operating Company, LLC	09/20	Bluegrass Water Utility Operating Company, LLC	2020-290	Capital Structure and Cost of Long-Term Debt
Maine Public Utilities Commission				
Unitil Corporation	06/19	Northern Utilities, Inc.	19-00092	Co-sponsored testimony supporting a proposed capital tracking mechanism
Michigan Public Service Commission				
DTE Electric Company	04/25	DTE Electric Company	U-21860	Cost of Capital
DTE Gas Company	11/25	DTE Gas Company	U-21973	Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Montana Public Utilities Commission				
NorthWestern Corporation	08/22	NorthWestern Corporation	2022-7-78 (elect.) 2022-7-78 (gas)	Alternative Ratemaking Proposals
New Hampshire Public Utilities Commission				
Unitil Energy Systems, Inc.	04/21	Unitil Energy Systems, Inc.	DE 21-030	Cost of Capital
New Mexico Public Regulation Commission				
El Paso Electric Company	07/20	El Paso Electric Company	20-00104-UT	Cost of Capital
North Carolina Utilities Commission				
Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	04/21	Public Service Company of North Carolina d/b/a Dominion Energy North Carolina	G-5, Sub 632	Cost of Capital
Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	03/24	Virginia Electric & Power Co., d/b/a Dominion Energy North Carolina	E-22, Sub 694	Cost of Capital
Public Service Company of North Carolina	04/25	Public Service Company of North Carolina	G-5, Sub 686	Cost of Capital
Public Utilities Commission of Ohio				
The East Ohio Gas Company d/b/a Dominion Energy Ohio	11/23	The East Ohio Gas Company d/b/a Dominion Energy Ohio	23-0894-GA-AIR	Cost of Capital
The East Ohio Gas Company d/b/a Enbridge Gas Ohio	01/26	The East Ohio Gas Company d/b/a Enbridge Gas Ohio	25-1097-GA-AIR	Cost of Capital
Oklahoma Corporation Commission				
Oklahoma Gas & Electric	12/21	Oklahoma Gas & Electric	PUD202100164	Formula Rate Plan
Public Utility Commission of Oregon				
Northwest Natural Gas Company d/b/a NW Natural	12/23	Northwest Natural Gas Company d/b/a NW Natural	UG 490	Cost of Capital
Northwest Natural Gas Company d/b/a NW Natural	12/24	Northwest Natural Gas Company d/b/a NW Natural	UG 520	Cost of Capital
Pennsylvania Public Utility Commission				
PPL Electric Utilities Corporation	09/25	PPL Electric Utilities Corporation	R-2025-3057164	Cost of Capital

SPONSOR	DATE	CASE/APPLICANT	DOCKET	SUBJECT
Public Utilities Commission of South Carolina				
Dominion Energy South Carolina	04/23	Dominion Energy South Carolina	2023-70-G	Cost of Capital
Dominion Energy South Carolina	03/24	Dominion Energy South Carolina	2024-34-E	Cost of Capital
Dominion Energy South Carolina, Inc.	01/26	Dominion Energy South Carolina, Inc.	2025-325-E	Cost of Capital
Public Utilities Commission of Texas				
Sharyland Utilities L.L.C.	12/20	Sharyland Utilities L.L.C.	51611	Cost of Capital
El Paso Electric Company	06/21	El Paso Electric Company	52195	Cost of Capital
Wind Energy Transmission Texas, LLC dba WETT	12/24	Wind Energy Transmission Texas, LLC dba WETT	57299	Cost of Capital
El Paso Electric Company	01/25	El Paso Electric Company	57568	Cost of Capital
Utah Public Service Commission				
Enbridge Gas Utah	05/25	Enbridge Gas Utah	25-057-06	Cost of Capital
Dominion Energy Utah	05/22	Dominion Energy Utah	22-057-03	Cost of Capital
Virginia State Corporation Commission				
Virginia Electric & Power Company (Dominion Energy Virginia)	03/25	Virginia Electric & Power Company (Dominion Energy Virginia)	PUR-2025-00058	Cost of Capital
Public Service Commission of West Virginia				
Hope Gas, Inc.	04/25	Hope Gas, Inc.	25-0417-G-42T	Cost of Capital
Hope Gas, Inc. d/b/a Dominion Energy West Virginia	11/20	Hope Gas, Inc. d/b/a Dominion Energy West Virginia	20-0746-G-42T	Cost of Capital
Washington Utilities & Transportation Commission				
Northwest Natural Gas Company d/b/a NW Natural	08/25	Northwest Natural Gas Company d/b/a NW Natural	UG-250610	Cost of Capital
Wyoming Public Service Commission				
Dominion Energy Wyoming	03/23	Dominion Energy Wyoming	30010-215-GR-23	Cost of Capital

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
30 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] CIQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Atmos Energy Corporation	ATO	$4.00	$167.81	2.38%	2.48%	6.50%	8.26%	8.50%	7.75%	8.96%	10.23%	10.98%
New Jersey Resources Corporation	NJR	$1.90	$47.20	4.03%	4.18%	n/a	8.40%	6.50%	7.45%	10.66%	11.63%	12.59%
NiSource Inc.	NI	$1.12	$42.61	2.63%	2.73%	6.00%	8.90%	8.00%	7.63%	8.71%	10.36%	11.65%
Northwest Natural Holding Co.	NWN	$1.97	$46.74	4.21%	4.34%	n/a	5.50%	6.50%	6.00%	9.83%	10.34%	10.85%
ONE Gas, Inc.	OGS	$2.68	$77.89	3.44%	3.55%	6.70%	7.10%	4.50%	6.10%	8.02%	9.65%	10.67%
Southwest Gas Holdings, Inc.	SWX	$2.48	$82.09	3.02%	3.17%	9.20%	10.50%	n/a	9.85%	12.36%	13.02%	13.68%
Spire, Inc.	SR	$3.30	$83.22	3.97%	4.13%	10.50%	9.60%	4.50%	8.20%	8.55%	12.33%	14.67%
Proxy Group Mean				3.38%	3.51%	7.78%	8.32%	6.42%	7.57%	9.58%	11.08%	12.16%
Proxy Group Median				3.44%	3.55%	6.70%	8.40%	6.50%	7.63%	8.96%	10.36%	11.65%
Average of the Mean and Median				**3.41%**	**3.53%**	**7.24%**	**8.36%**	**6.46%**	**7.60%**	**9.27%**	**10.72%**	**11.90%**

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 1/30/2026
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: S&P Capital IQ
[7] Source: Value Line
[8] Equals Average (Cols. [5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
90 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] CIQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Atmos Energy Corporation	ATO	$4.00	$171.40	2.33%	2.42%	6.50%	8.26%	8.50%	7.75%	8.91%	10.18%	10.93%
New Jersey Resources Corporation	NJR	$1.90	$46.59	4.08%	4.23%	n/a	8.40%	6.50%	7.45%	10.71%	11.68%	12.65%
NiSource Inc.	NI	$1.12	$42.79	2.62%	2.72%	6.00%	8.90%	8.00%	7.63%	8.70%	10.35%	11.63%
Northwest Natural Holding Co.	NWN	$1.97	$46.47	4.24%	4.37%	n/a	5.50%	6.50%	6.00%	9.86%	10.37%	10.88%
ONE Gas, Inc.	OGS	$2.68	$79.74	3.36%	3.46%	6.70%	7.10%	4.50%	6.10%	7.94%	9.56%	10.58%
Southwest Gas Holdings, Inc.	SWX	$2.48	$80.57	3.08%	3.23%	9.20%	10.50%	n/a	9.85%	12.42%	13.08%	13.74%
Spire, Inc.	SR	$3.30	$84.45	3.91%	4.07%	10.50%	9.60%	4.50%	8.20%	8.50%	12.27%	14.61%
Proxy Group Mean				3.37%	3.50%	7.78%	8.32%	6.42%	7.57%	9.57%	11.07%	12.15%
Proxy Group Median				3.36%	3.46%	6.70%	8.40%	6.50%	7.63%	8.91%	10.37%	11.63%
Average of the Mean and Median				**3.37%**	**3.48%**	**7.24%**	**8.36%**	**6.46%**	**7.60%**	**9.24%**	**10.72%**	**11.89%**

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 1/30/2026
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: S&P Capital IQ
[7] Source: Value Line
[8] Equals Average (Cols. [5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Constant Growth Discounted Cash Flow Model with Half Year Growth Adjustment
180 Day Average Stock Price

Company	Ticker	[1] Annualized Dividend	[2] Average Stock Price	[3] Dividend Yield	[4] Expected Dividend Yield	[5] Zacks Earnings Growth	[6] CIQ Earnings Growth	[7] Value Line Earnings Growth	[8] Average Earnings Growth	[9] Low ROE	[10] Mean ROE	[11] High ROE
Atmos Energy Corporation	ATO	$4.00	$164.95	2.43%	2.52%	6.50%	8.26%	8.50%	7.75%	9.00%	10.27%	11.03%
New Jersey Resources Corporation	NJR	$1.90	$46.33	4.10%	4.25%	n/a	8.40%	6.50%	7.45%	10.73%	11.70%	12.67%
NiSource Inc.	NI	$1.12	$41.70	2.69%	2.79%	6.00%	8.90%	8.00%	7.63%	8.77%	10.42%	11.71%
Northwest Natural Holding Co.	NWN	$1.97	$43.69	4.51%	4.64%	n/a	5.50%	6.50%	6.00%	10.13%	10.64%	11.16%
ONE Gas, Inc.	OGS	$2.68	$76.94	3.48%	3.59%	6.70%	7.10%	4.50%	6.10%	8.06%	9.69%	10.71%
Southwest Gas Holdings, Inc.	SWX	$2.48	$78.18	3.17%	3.33%	9.20%	10.50%	n/a	9.85%	12.52%	13.18%	13.84%
Spire, Inc.	SR	$3.30	$79.70	4.14%	4.31%	10.50%	9.60%	4.50%	8.20%	8.73%	12.51%	14.86%
Proxy Group Mean				3.50%	3.63%	7.78%	8.32%	6.42%	7.57%	9.71%	11.20%	12.28%
Proxy Group Median				3.48%	3.59%	6.70%	8.40%	6.50%	7.63%	9.00%	10.64%	11.71%
Average of the Mean and Median				**3.49%**	**3.61%**	**7.24%**	**8.36%**	**6.46%**	**7.60%**	**9.36%**	**10.92%**	**11.99%**

Notes:

[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ, equals indicated number of trading day average as of 1/30/2026
[3] Equals [1] / [2]
[4] Equals [3] x (1 + 0.5 x [8])
[5] Source: Zacks
[6] Source: S&P Capital IQ
[7] Source: Value Line
[8] Equals Average (Cols. [5], [6], [7])
[9] Equals [3] x (1 + 0.5 x Minimum([5], [6], [7])) + Minimum([5], [6], [7])
[10] Equals [4] + [8]
[11] Equals [3] x (1 + 0.5 x Maximum([5], [6], [7])) + Maximum([5], [6], [7])

Quarterly Growth Discounted Cash Flow Model
30 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] CIQ Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Atmos Energy Corporation	ATO	$0.87	$0.87	$0.87	$1.00	$0.94	$0.94	$0.94	$1.08	$167.81	6.50%	8.26%	8.50%	7.75%	8.86%	10.16%	10.92%
New Jersey Resources Corporation	NJR	$0.45	$0.45	$0.48	$0.48	$0.48	$0.48	$0.51	$0.51	$47.20	n/a	8.40%	6.50%	7.45%	10.84%	11.84%	12.84%
NiSource Inc.	NI	$0.28	$0.28	$0.28	$0.28	$0.30	$0.30	$0.30	$0.30	$42.61	6.00%	8.90%	8.00%	7.63%	8.88%	10.57%	11.89%
Northwest Natural Holding Co.	NWN	$0.49	$0.49	$0.49	$0.49	$0.52	$0.52	$0.52	$0.52	$46.74	n/a	5.50%	6.50%	6.00%	10.10%	10.63%	11.16%
ONE Gas, Inc.	OGS	$0.67	$0.67	$0.67	$0.67	$0.71	$0.71	$0.71	$0.71	$77.89	6.70%	7.10%	4.50%	6.10%	8.20%	9.88%	10.94%
Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.62	$0.62	$0.68	$0.68	$0.68	$0.68	$82.09	9.20%	10.50%	n/a	9.85%	12.65%	13.33%	14.01%
Spire, Inc.	SR	$0.79	$0.79	$0.79	$0.83	$0.85	$0.85	$0.85	$0.89	$83.22	10.50%	9.60%	4.50%	8.20%	8.62%	12.52%	14.95%
Proxy Group Mean											7.78%	8.32%	6.42%	7.57%	9.74%	11.28%	12.39%
Proxy Group Median											6.70%	8.40%	6.50%	7.63%	8.88%	10.63%	11.89%
Average of Mean and Median															9.31%	10.95%	12.14%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ
[3] Source: S&P Capital IQ
[4] Source: S&P Capital IQ
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: S&P Capital IQ, equals indicated number of trading day average as of 1/30/2026
[10] Source: Zacks
[11] Source: S&P Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
90 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] CIQ Earnings Growth	[12] Value Line Earnings Growth	[13] Average Earnings Growth	[14] Low ROE	[15] Mean ROE	[16] High ROE
Atmos Energy Corporation	ATO	$0.87	$0.87	$0.87	$1.00	$0.94	$0.94	$0.94	$1.08	$171.40	6.50%	8.26%	8.50%	7.75%	8.81%	10.10%	10.87%
New Jersey Resources Corporation	NJR	$0.45	$0.45	$0.48	$0.48	$0.48	$0.48	$0.51	$0.51	$46.59	n/a	8.40%	6.50%	7.45%	10.89%	11.90%	12.90%
NiSource Inc.	NI	$0.28	$0.28	$0.28	$0.28	$0.30	$0.30	$0.30	$0.30	$42.79	6.00%	8.90%	8.00%	7.63%	8.87%	10.56%	11.87%
Northwest Natural Holding Co.	NWN	$0.49	$0.49	$0.49	$0.49	$0.52	$0.52	$0.52	$0.52	$46.47	n/a	5.50%	6.50%	6.00%	10.13%	10.66%	11.19%
ONE Gas, Inc.	OGS	$0.67	$0.67	$0.67	$0.67	$0.71	$0.71	$0.71	$0.71	$79.74	6.70%	7.10%	4.50%	6.10%	8.12%	9.80%	10.85%
Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.62	$0.62	$0.68	$0.68	$0.68	$0.68	$80.57	9.20%	10.50%	n/a	9.85%	12.72%	13.40%	14.08%
Spire, Inc.	SR	$0.79	$0.79	$0.79	$0.83	$0.85	$0.85	$0.85	$0.89	$84.45	10.50%	9.60%	4.50%	8.20%	8.56%	12.46%	14.88%
Proxy Group Mean											7.78%	8.32%	6.42%	7.57%	9.73%	11.27%	12.38%
Proxy Group Median											6.70%	8.40%	6.50%	7.63%	8.87%	10.66%	11.87%
Average of Mean and Median															9.30%	10.96%	12.13%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ
[3] Source: S&P Capital IQ
[4] Source: S&P Capital IQ
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: S&P Capital IQ, equals indicated number of trading day average as of 1/30/2026
[10] Source: Zacks
[11] Source: S&P Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Quarterly Growth Discounted Cash Flow Model
180 Day Average Stock Price

Company	Ticker	[1] Dividend 1	[2] Dividend 2	[3] Dividend 3	[4] Dividend 4	[5] Expected Dividend 1	[6] Expected Dividend 2	[7] Expected Dividend 3	[8] Expected Dividend 4	[9] Average Stock Price	[10] Zacks Earnings Growth	[11] CIQ Earnings Growth	[12] Value Line Earnings Growth	[14] Average Earnings Growth	[15] Low ROE	[16] Mean ROE	[17] High ROE
Atmos Energy Corporation	ATO	$0.87	$0.87	$0.87	$1.00	$0.94	$0.94	$0.94	$1.08	$164.95	6.50%	8.26%	8.50%	7.75%	8.90%	10.20%	10.97%
New Jersey Resources Corporation	NJR	$0.45	$0.45	$0.48	$0.48	$0.48	$0.48	$0.51	$0.51	$46.33	n/a	8.40%	6.50%	7.45%	10.92%	11.92%	12.93%
NiSource Inc.	NI	$0.28	$0.28	$0.28	$0.28	$0.30	$0.30	$0.30	$0.30	$41.70	6.00%	8.90%	8.00%	7.63%	8.94%	10.64%	11.95%
Northwest Natural Holding Co.	NWN	$0.49	$0.49	$0.49	$0.49	$0.52	$0.52	$0.52	$0.52	$43.69	n/a	5.50%	6.50%	6.00%	10.43%	10.96%	11.49%
ONE Gas, Inc.	OGS	$0.67	$0.67	$0.67	$0.67	$0.71	$0.71	$0.71	$0.71	$76.94	6.70%	7.10%	4.50%	6.10%	8.25%	9.93%	10.98%
Southwest Gas Holdings, Inc.	SWX	$0.62	$0.62	$0.62	$0.62	$0.68	$0.68	$0.68	$0.68	$78.18	9.20%	10.50%	n/a	9.85%	12.83%	13.51%	14.19%
Spire, Inc.	SR	$0.79	$0.79	$0.79	$0.83	$0.85	$0.85	$0.85	$0.89	$79.70	10.50%	9.60%	4.50%	8.20%	8.80%	12.72%	15.15%
Proxy Group Mean											7.78%	8.32%	6.42%	7.57%	9.87%	11.41%	12.52%
Proxy Group Median											6.70%	8.40%	6.50%	7.63%	8.94%	10.96%	11.95%
Average of Mean and Median															9.40%	11.18%	12.24%

Notes:
[1] Source: S&P Capital IQ
[2] Source: S&P Capital IQ
[3] Source: S&P Capital IQ
[4] Source: S&P Capital IQ
[5] Equals Col. [1] x (1 + Col. [13])
[6] Equals Col. [2] x (1 + Col. [13])
[7] Equals Col. [3] x (1 + Col. [13])
[8] Equals Col. [4] x (1 + Col. [13])
[9] Source: S&P Capital IQ, equals indicated number of trading day average as of 1/30/2026
[10] Source: Zacks
[11] Source: S&P Capital IQ
[12] Source: Value Line
[13] Equals Average (Cols. [10], [11], [12])
[14] Implied Low DCF
[15] Implied Mean DCF
[16] Implied High DCF

Forward Market Return
Market DCF Based Method - Value Line EPS Growth

[1] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.15%
[2] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	15.14%
[3] Market Cap. Weighted Estimated Required Market Return	16.38%

Notes:
[1] Source: S&P Capital IQ as of 1/31/2026
[2] Source: Value Line DCF-based expected market return. See Confidential WP-12 for calculation
[3] Equals ([1] x (1 + (0.5 x [2]))) + [2]

Forward Market Return
Market DCF Based Method - Bloomberg EPS Growth

[4] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.17%
[5] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	17.81%
[6] Market Cap. Weighted Estimated Required Market Return	19.08%

Notes:
[4] Source: S&P Capital IQ as of 1/31/2026
[5] Source: Bloomberg DCF-based expected market return. See Confidential WP-13 for calculation
[6] Equals ([4] x (1 + (0.5 x [5]))) + [5]

Forward Market Return
Market DCF Based Method - S&P 500 EPS Growth

[7] Market Cap. Weighted Estimate of the S&P 500 Dividend Yield	1.15%
[8] Market Cap. Weighted Estimate of the S&P 500 Growth Rate	17.31%
[9] Market Cap. Weighted Estimated Required Market Return	18.56%

Notes:
[7], [8] Source: S&P Global, S&P 500 Earnings and Estimate Report, January 31, 2026
[9] Equals (Col. [7] x (1 + (0.5 x Col. Col. [8]))) + Col. Col. [8]

Summary of CAPM and ECAPM Results

	Current 30-Year Treasury Yield (4.92%)	**Projected 30-Year Treasury Yield (4.52%)**	**Average**
CAPM Forward Market Return	13.11%	13.06%	13.09%
ECAPM Forward Market Return	13.93%	13.89%	13.91%
CAPM Historical Market Return	10.14%	10.09%	10.11%
ECAPM Historical Market Return	10.66%	10.63%	10.64%
			11.94%

Source: Exhibit JEN-5, pages 2-5

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using DCF-derived Expected Market Return and 5-year Beta Coefficients

Company	Ticker	[1] Current 30-Year Treasury Yield	[2] 5-Year Bloomberg Beta Coefficient	[3] 5-Year Value Line Beta Coefficient	[4] Average Beta Coefficient	[5] DCF Forward Market Return	[6] Market Risk Premium	[7] Traditional CAPM	[8] Empirical CAPM
Atmos Energy Corporation	ATO	4.83%	0.64	0.75	0.70	16.38%	11.55%	12.87%	13.75%
New Jersey Resources Corporation	NJR	4.83%	0.61	0.75	0.68	16.38%	11.55%	12.66%	13.59%
NiSource Inc.	NI	4.83%	0.68	0.85	0.76	16.38%	11.55%	13.65%	14.33%
Northwest Natural Holding Co.	NWN	4.83%	0.58	0.75	0.67	16.38%	11.55%	12.51%	13.48%
ONE Gas, Inc.	OGS	4.83%	0.59	0.75	0.67	16.38%	11.55%	12.54%	13.50%
Southwest Gas Holdings, Inc.	SWX	4.83%	0.65	0.75	0.70	16.38%	11.55%	12.90%	13.77%
Spire, Inc.	SR	4.83%	0.62	0.75	0.69	16.38%	11.55%	12.76%	13.66%
							Proxy Group Mean:	12.84%	13.73%
							Proxy Group Median:	12.76%	13.66%
							Average of the Mean and Median:	**12.80%**	**13.70%**

Company	Ticker	[9] Projected 30-Year Treasury Yield	[10] 5-Year Bloomberg Beta Coefficient	[11] 5-Year Value Line Beta Coefficient	[12] Average Beta Coefficient	[13] DCF Forward Market Return	[14] Market Risk Premium	[15] Traditional CAPM	[16] Empirical CAPM
Atmos Energy Corporation	ATO	4.68%	0.64	0.75	0.70	16.38%	11.70%	12.82%	13.71%
New Jersey Resources Corporation	NJR	4.68%	0.61	0.75	0.68	16.38%	11.70%	12.61%	13.56%
NiSource Inc.	NI	4.68%	0.68	0.85	0.76	16.38%	11.70%	13.62%	14.31%
Northwest Natural Holding Co.	NWN	4.68%	0.58	0.75	0.67	16.38%	11.70%	12.46%	13.44%
ONE Gas, Inc.	OGS	4.68%	0.59	0.75	0.67	16.38%	11.70%	12.49%	13.46%
Southwest Gas Holdings, Inc.	SWX	4.68%	0.65	0.75	0.70	16.38%	11.70%	12.85%	13.73%
Spire, Inc.	SR	4.68%	0.62	0.75	0.69	16.38%	11.70%	12.71%	13.63%
							Proxy Group Mean:	12.80%	13.69%
							Proxy Group Median:	12.71%	13.63%
							Average of the Mean and Median:	**12.75%**	**13.66%**

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Source: Exhibit JEN-4; Value Line DCF-based forward market return
[6] Equals Col. [5] - Col. [1]
[7] Equals Col. [1] + (Col. [4] x Col. [6])
[8] Equals Col. [1] + (0.75 x Col. [4] x Col. [6]) + (0.25 x Col. [6])
[9] Source: Blue Chip Financial Forecasts, Vol. 45, No. 2, January 30, 2026 at 2 and Vol. 44, No. 12, December 1, 2025 at 14
[10] See Note [2]
[11] See Note [3]
[12] Equals Average of Col. [10] and Col. [11]
[13] See Note [5]
[14] Equals Col. [13] - Col. [9]
[15] Equals Col. [9] + (Col. [12] x Col. [14])
[16] Equals Col. [9] + (0.75 x Col. [12] x Col. [14]) + (0.25 x Col. [14])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using DCF-derived Expected Market Return and 10-Year Bloomberg Beta Coefficient

		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-Year Treasury Yield	10-Year Bloomberg Beta Coefficient	DCF Forward Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.83%	0.72	16.38%	11.55%	13.16%	13.96%
New Jersey Resources Corporation	NJR	4.83%	0.76	16.38%	11.55%	13.57%	14.27%
NiSource Inc.	NI	4.83%	0.77	16.38%	11.55%	13.73%	14.40%
Northwest Natural Holding Co.	NWN	4.83%	0.68	16.38%	11.55%	12.67%	13.59%
ONE Gas, Inc.	OGS	4.83%	0.73	16.38%	11.55%	13.30%	14.07%
Southwest Gas Holdings, Inc.	SWX	4.83%	0.81	16.38%	11.55%	14.23%	14.77%
Spire, Inc.	SR	4.83%	0.74	16.38%	11.55%	13.40%	14.14%
					Proxy Group Mean:	13.44%	14.17%
					Proxy Group Median:	13.40%	14.14%
					Average of the Mean and Median:	**13.42%**	**14.16%**

		[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Projected 30-Year Treasury Yield	10-Year Bloomberg Beta Coefficient	DCF Forward Market Return	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.68%	0.72	16.38%	11.70%	13.11%	13.93%
New Jersey Resources Corporation	NJR	4.68%	0.76	16.38%	11.70%	13.53%	14.25%
NiSource Inc.	NI	4.68%	0.77	16.38%	11.70%	13.70%	14.37%
Northwest Natural Holding Co.	NWN	4.68%	0.68	16.38%	11.70%	12.62%	13.56%
ONE Gas, Inc.	OGS	4.68%	0.73	16.38%	11.70%	13.26%	14.04%
Southwest Gas Holdings, Inc.	SWX	4.68%	0.81	16.38%	11.70%	14.20%	14.75%
Spire, Inc.	SR	4.68%	0.74	16.38%	11.70%	13.36%	14.11%
					Proxy Group Mean:	13.40%	14.14%
					Proxy Group Median:	13.36%	14.11%
					Average of the Mean and Median:	**13.38%**	**14.13%**

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Exhibit JEN-4; Value Line DCF-based forward market return
[4] Equals Col. [3] - Col. [1]
[5] Equals Col. [1] + (Col. [2] x Col. [4])
[6] Equals Col. [1] + (0.75 x Col. [2] x Col. [4]) + (0.25 x Col. [4])
[7] Source: Blue Chip Financial Forecasts, Vol. 45, No. 2, January 30, 2026 at 2 and Vol. 44, No. 12, December 1, 2025 at 14
[8] See Note [2]
[9] See Note [3]
[10] Equals Col. [9] - Col. [7]
[11] Equals Col. [7] + (Col. [8] x Col. [10])
[12] Equals Col. [7] + (0.75 x Col. [8] x Col. [10]) + (0.25 x Col. [10])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Long-Term Historical Market Return and 5-year Beta Coefficients

		[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]
Company	Ticker	Current 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2025)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.83%	0.64	0.75	0.70	12.23%	7.40%	9.98%	10.54%
New Jersey Resources Corporation	NJR	4.83%	0.61	0.75	0.68	12.23%	7.40%	9.85%	10.45%
NiSource Inc.	NI	4.83%	0.68	0.85	0.76	12.23%	7.40%	10.48%	10.92%
Northwest Natural Holding Co.	NWN	4.83%	0.58	0.75	0.67	12.23%	7.40%	9.75%	10.37%
ONE Gas, Inc.	OGS	4.83%	0.59	0.75	0.67	12.23%	7.40%	9.77%	10.39%
Southwest Gas Holdings, Inc.	SWX	4.83%	0.65	0.75	0.70	12.23%	7.40%	10.00%	10.56%
Spire, Inc.	SR	4.83%	0.62	0.75	0.69	12.23%	7.40%	9.91%	10.49%
							Proxy Group Mean:	9.96%	10.53%
							Proxy Group Median:	9.91%	10.49%
							Average of the Mean and Median:	**9.94%**	**10.51%**

		[9]	[10]	[11]	[12]	[13]	[14]	[15]	[16]
Company	Ticker	Projected 30-Year Treasury Yield	5-Year Bloomberg Beta Coefficient	5-Year Value Line Beta Coefficient	Average Beta Coefficient	Long-Term Average Historical Market Return (1926-2025)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.68%	0.64	0.75	0.70	12.23%	7.56%	9.93%	10.51%
New Jersey Resources Corporation	NJR	4.68%	0.61	0.75	0.68	12.23%	7.56%	9.80%	10.41%
NiSource Inc.	NI	4.68%	0.68	0.85	0.76	12.23%	7.56%	10.45%	10.89%
Northwest Natural Holding Co.	NWN	4.68%	0.58	0.75	0.67	12.23%	7.56%	9.70%	10.33%
ONE Gas, Inc.	OGS	4.68%	0.59	0.75	0.67	12.23%	7.56%	9.72%	10.35%
Southwest Gas Holdings, Inc.	SWX	4.68%	0.65	0.75	0.70	12.23%	7.56%	9.95%	10.52%
Spire, Inc.	SR	4.68%	0.62	0.75	0.69	12.23%	7.56%	9.86%	10.45%
							Proxy Group Mean:	9.92%	10.49%
							Proxy Group Median:	9.86%	10.45%
							Average of the Mean and Median:	**9.89%**	**10.47%**

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average
[2] Source: Bloomberg Professional Service
[3] Source: Value Line
[4] Equals Average of Col. [2] and Col. [3]
[5] Kroll, Cost of Capital Navigator
[6] Equals Col. [5] - Col. [1]
[7] Equals Col. [1] + (Col. [4] x Col. [6])
[8] Equals Col. [1] + (0.75 x Col. [4] x Col. [6]) + (0.25 x Col. [6])
[9] Source: Blue Chip Financial Forecasts, Vol. 45, No. 2, January 30, 2026 at 2 and Vol. 44, No. 12, December 1, 2025 at 14
[10] See Note [2]
[11] See Note [3]
[12] Equals Average of Col. [10] and Col. [11]
[13] See Note [5]
[14] Equals Col. [13] - Col. [9]
[15] Equals Col. [9] + (Col. [12] x Col. [14])
[16] Equals Col. [9] + (0.75 x Col. [12] x Col. [14]) + (0.25 x Col. [14])

Capital Asset Pricing Model and Empirical Capital Asset Pricing Model Results
Using Long-Term Historical Market Return and 10-Year Bloomberg Beta Coefficient

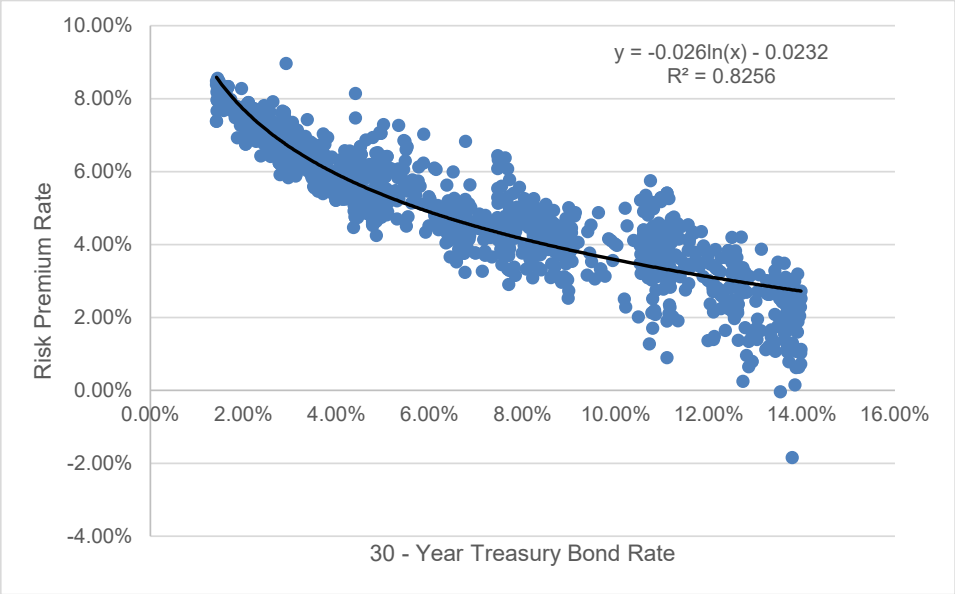
		[1]	[2]	[3]	[4]	[5]	[6]
Company	Ticker	Current 30-Year Treasury Yield	10-Year Bloomberg Beta Coefficient	Long-Term Average Historical Market Return (1926-2025)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.83%	0.72	12.23%	7.40%	10.16%	10.68%
New Jersey Resources Corporation	NJR	4.83%	0.76	12.23%	7.40%	10.43%	10.88%
NiSource Inc.	NI	4.83%	0.77	12.23%	7.40%	10.54%	10.96%
Northwest Natural Holding Co.	NWN	4.83%	0.68	12.23%	7.40%	9.85%	10.45%
ONE Gas, Inc.	OGS	4.83%	0.73	12.23%	7.40%	10.26%	10.75%
Southwest Gas Holdings, Inc.	SWX	4.83%	0.81	12.23%	7.40%	10.85%	11.20%
Spire, Inc.	SR	4.83%	0.74	12.23%	7.40%	10.32%	10.80%
					Proxy Group Mean:	10.34%	10.82%
					Proxy Group Median:	10.32%	10.80%
					Average of the Mean and Median:	**10.33%**	**10.81%**

		[7]	[8]	[9]	[10]	[11]	[12]
Company	Ticker	Projected 30-Year Treasury Yield	10-Year Bloomberg Beta Coefficient	Long-Term Average Historical Market Return (1926-2025)	Market Risk Premium	Traditional CAPM	Empirical CAPM
Atmos Energy Corporation	ATO	4.68%	0.72	12.23%	7.56%	10.12%	10.65%
New Jersey Resources Corporation	NJR	4.68%	0.76	12.23%	7.56%	10.39%	10.85%
NiSource Inc.	NI	4.68%	0.77	12.23%	7.56%	10.50%	10.93%
Northwest Natural Holding Co.	NWN	4.68%	0.68	12.23%	7.56%	9.80%	10.41%
ONE Gas, Inc.	OGS	4.68%	0.73	12.23%	7.56%	10.21%	10.72%
Southwest Gas Holdings, Inc.	SWX	4.68%	0.81	12.23%	7.56%	10.83%	11.18%
Spire, Inc.	SR	4.68%	0.74	12.23%	7.56%	10.28%	10.77%
					Proxy Group Mean:	10.31%	10.79%
					Proxy Group Median:	10.28%	10.77%
					Average of the Mean and Median:	**10.29%**	**10.78%**

Notes:
[1] Source: Federal Reserve Bank of St. Louis (FRED); 30-day average
[2] Source: Bloomberg Professional Service
[3] Kroll, Cost of Capital Navigator
[4] Equals Col. [3] - Col. [1]
[5] Equals Col. [1] + (Col. [2] x Col. [4])
[6] Equals Col. [1] + (0.75 x Col. [2] x Col. [4]) + (0.25 x Col. [4])
[7] Source: Blue Chip Financial Forecasts, Vol. 45, No. 2, January 30, 2026 at 2 and Vol. 44, No. 12, December 1, 2025 at 14
[8] See Note [2]
[9] See Note [3]
[10] Equals Col. [9] - Col. [7]
[11] Equals Col. [7] + (Col. [8] x Col. [10])
[12] Equals Col. [7] + (0.75 x Col. [8] x Col. [10]) + (0.25 x Col. [10])

Bond Yield Plus Risk Premium

[1]	[2]	[3]	[4]	[5]
Constant	Slope	30-Year Treasury Yield	Risk Premium	Return on Equity
-2.32%	-2.56%			
Current 30-Year Treasury		4.83%	5.45%	10.28%
Projected 30-Year Treasury		4.68%	5.53%	10.21%



Notes:
[1] Constant of regression equation
[2] Slope of regression equation
[3] Sources: Current = Federal Reserve Bank of St. Louis,
Projected = Average of near-term and long-term projected 30-year Treasury yield from
Blue Chip Financial Forecasts, Vol. 45, No. 2, January 30, 2026 at 2 and Vol. 44, No. 12, December 1, 2025 at 14
[4] Equals [1] + ln([3]) x [2]
[5] Equals [3] + [4]
[6] Source: S&P Capital IQ
[7] Source: S&P Capital IQ
[8] Source: Bloomberg Professional, equals 189-trading day average (i.e. lag period)
[9] Equals [7] - [8]

Bond Yield Plus Risk Premium

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/3/1980	12.55%	9.39%	3.16%
1/4/1980	13.75%	9.40%	4.35%
1/14/1980	13.20%	9.44%	3.76%
1/18/1980	14.00%	9.47%	4.53%
1/31/1980	12.61%	9.55%	3.06%
2/8/1980	14.50%	9.63%	4.87%
2/14/1980	13.00%	9.67%	3.33%
2/15/1980	13.00%	9.69%	3.31%
2/29/1980	14.00%	9.85%	4.15%
3/5/1980	14.00%	9.90%	4.10%
3/7/1980	13.50%	9.94%	3.56%
3/14/1980	14.00%	10.02%	3.98%
3/27/1980	12.69%	10.19%	2.50%
4/1/1980	14.75%	10.24%	4.51%
4/29/1980	12.50%	10.49%	2.01%
5/7/1980	14.27%	10.54%	3.73%
5/8/1980	13.75%	10.55%	3.20%
5/19/1980	15.50%	10.60%	4.90%
5/27/1980	14.60%	10.64%	3.96%
5/29/1980	16.00%	10.65%	5.35%
6/10/1980	13.78%	10.69%	3.09%
6/25/1980	14.25%	10.72%	3.53%
7/9/1980	14.51%	10.76%	3.75%
7/17/1980	12.90%	10.78%	2.12%
7/18/1980	13.80%	10.78%	3.02%
7/22/1980	14.10%	10.78%	3.32%
7/23/1980	14.19%	10.79%	3.40%
8/1/1980	12.50%	10.80%	1.70%
8/11/1980	14.85%	10.81%	4.04%
8/21/1980	13.03%	10.84%	2.19%
8/28/1980	13.61%	10.86%	2.75%
8/28/1980	14.00%	10.86%	3.14%
9/4/1980	14.00%	10.89%	3.11%
9/24/1980	15.00%	10.97%	4.03%
10/9/1980	14.50%	11.05%	3.45%
10/9/1980	14.50%	11.05%	3.45%
10/24/1980	14.00%	11.09%	2.91%
10/27/1980	15.20%	11.10%	4.10%
10/27/1980	15.20%	11.10%	4.10%
10/28/1980	12.00%	11.10%	0.90%
10/28/1980	13.00%	11.10%	1.90%
10/31/1980	14.50%	11.12%	3.38%
11/4/1980	15.00%	11.13%	3.87%
11/6/1980	14.35%	11.14%	3.21%
11/10/1980	13.25%	11.15%	2.10%
11/17/1980	15.50%	11.16%	4.34%
11/19/1980	13.50%	11.16%	2.34%
12/5/1980	14.60%	11.15%	3.45%
12/8/1980	16.40%	11.15%	5.25%
12/12/1980	15.45%	11.16%	4.29%
12/17/1980	14.40%	11.17%	3.23%
12/17/1980	14.20%	11.17%	3.03%
12/18/1980	14.00%	11.17%	2.83%
12/22/1980	13.45%	11.17%	2.28%
12/26/1980	14.00%	11.16%	2.84%
12/30/1980	14.50%	11.15%	3.35%
12/31/1980	14.56%	11.15%	3.41%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/7/1981	14.30%	11.14%	3.16%
1/12/1981	14.95%	11.14%	3.81%
1/26/1981	15.25%	11.20%	4.05%
1/30/1981	13.25%	11.23%	2.02%
2/11/1981	14.50%	11.32%	3.18%
2/20/1981	14.50%	11.39%	3.11%
3/12/1981	15.65%	11.58%	4.07%
3/25/1981	15.30%	11.72%	3.58%
4/1/1981	15.30%	11.80%	3.50%
4/8/1981	15.00%	11.88%	3.12%
4/29/1981	13.50%	12.10%	1.40%
4/29/1981	14.25%	12.10%	2.15%
4/30/1981	15.00%	12.12%	2.88%
4/30/1981	13.60%	12.12%	1.48%
5/21/1981	14.00%	12.36%	1.64%
6/3/1981	14.67%	12.44%	2.23%
6/22/1981	16.00%	12.56%	3.44%
6/25/1981	14.75%	12.59%	2.16%
7/2/1981	14.00%	12.63%	1.37%
7/10/1981	16.00%	12.68%	3.32%
7/14/1981	16.90%	12.70%	4.20%
7/21/1981	15.78%	12.76%	3.02%
7/27/1981	13.77%	12.81%	0.96%
7/27/1981	15.50%	12.81%	2.69%
7/31/1981	14.20%	12.86%	1.34%
7/31/1981	13.50%	12.86%	0.64%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	13.72%	12.93%	0.79%
8/12/1981	14.41%	12.93%	1.48%
8/25/1981	15.45%	13.01%	2.44%
8/27/1981	14.43%	13.04%	1.39%
8/28/1981	15.00%	13.05%	1.95%
9/23/1981	14.34%	13.23%	1.11%
9/24/1981	16.25%	13.24%	3.01%
9/29/1981	14.50%	13.29%	1.21%
9/30/1981	15.94%	13.31%	2.63%
10/2/1981	14.80%	13.34%	1.46%
10/12/1981	16.25%	13.41%	2.84%
10/20/1981	15.25%	13.49%	1.76%
10/20/1981	17.00%	13.49%	3.51%
10/20/1981	16.50%	13.49%	3.01%
10/23/1981	15.50%	13.53%	1.97%
10/26/1981	13.50%	13.54%	-0.04%
10/29/1981	16.50%	13.58%	2.92%
11/4/1981	15.33%	13.61%	1.72%
11/6/1981	15.17%	13.63%	1.54%
11/12/1981	15.00%	13.64%	1.36%
11/25/1981	16.10%	13.65%	2.45%
11/25/1981	16.10%	13.65%	2.45%
11/25/1981	15.25%	13.65%	1.60%
11/30/1981	16.75%	13.65%	3.10%
12/1/1981	15.70%	13.65%	2.05%
12/1/1981	16.00%	13.65%	2.35%
12/15/1981	15.81%	13.68%	2.13%
12/17/1981	14.75%	13.69%	1.06%
12/22/1981	16.00%	13.71%	2.29%
12/22/1981	15.70%	13.71%	1.99%
12/30/1981	16.00%	13.73%	2.27%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/30/1981	16.25%	13.73%	2.52%
1/4/1982	15.50%	13.74%	1.76%
1/14/1982	11.95%	13.80%	-1.85%
1/25/1982	16.25%	13.84%	2.41%
1/27/1982	16.84%	13.85%	2.99%
1/31/1982	14.00%	13.85%	0.15%
2/2/1982	16.24%	13.86%	2.38%
2/8/1982	15.50%	13.88%	1.62%
2/9/1982	14.95%	13.88%	1.07%
2/9/1982	15.75%	13.88%	1.87%
2/11/1982	16.00%	13.89%	2.11%
3/1/1982	15.96%	13.90%	2.06%
3/3/1982	15.00%	13.90%	1.10%
3/8/1982	17.10%	13.91%	3.19%
3/26/1982	16.00%	13.96%	2.04%
3/31/1982	16.25%	13.97%	2.28%
4/1/1982	16.50%	13.97%	2.53%
4/5/1982	15.00%	13.98%	1.02%
4/8/1982	16.50%	13.98%	2.52%
4/11/1982	15.10%	13.98%	1.12%
4/11/1982	16.70%	13.98%	2.72%
4/17/1982	14.70%	13.98%	0.72%
4/27/1982	15.00%	13.97%	1.03%
5/10/1982	14.57%	13.94%	0.63%
5/14/1982	15.80%	13.92%	1.88%
5/20/1982	15.82%	13.91%	1.91%
5/21/1982	15.50%	13.90%	1.60%
5/25/1982	16.25%	13.90%	2.35%
6/2/1982	14.50%	13.88%	0.62%
6/7/1982	16.00%	13.86%	2.14%
6/23/1982	15.50%	13.82%	1.68%
6/25/1982	16.50%	13.82%	2.68%
7/1/1982	16.00%	13.81%	2.19%
7/1/1982	15.55%	13.81%	1.74%
7/2/1982	15.10%	13.80%	1.30%
7/13/1982	16.80%	13.76%	3.04%
7/22/1982	14.50%	13.72%	0.78%
7/28/1982	16.10%	13.70%	2.40%
7/30/1982	14.82%	13.68%	1.14%
8/4/1982	15.58%	13.65%	1.93%
8/6/1982	16.50%	13.64%	2.86%
8/11/1982	17.11%	13.62%	3.49%
8/25/1982	16.00%	13.58%	2.42%
8/30/1982	16.25%	13.57%	2.68%
9/3/1982	15.50%	13.56%	1.94%
9/9/1982	16.04%	13.54%	2.50%
9/15/1982	16.04%	13.52%	2.52%
9/17/1982	15.25%	13.51%	1.74%
9/29/1982	14.50%	13.43%	1.07%
9/30/1982	16.50%	13.42%	3.08%
9/30/1982	16.70%	13.42%	3.28%
9/30/1982	15.50%	13.42%	2.08%
9/30/1982	14.74%	13.42%	1.32%
10/1/1982	16.50%	13.41%	3.09%
10/8/1982	15.00%	13.34%	1.66%
10/15/1982	15.90%	13.27%	2.63%
10/19/1982	15.90%	13.23%	2.67%
10/27/1982	17.00%	13.13%	3.87%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/28/1982	14.75%	13.12%	1.63%
11/2/1982	16.25%	13.09%	3.16%
11/4/1982	15.75%	13.05%	2.70%
11/5/1982	14.73%	13.03%	1.70%
11/17/1982	16.00%	12.88%	3.12%
11/23/1982	15.50%	12.80%	2.70%
11/24/1982	16.02%	12.78%	3.24%
11/24/1982	14.50%	12.78%	1.72%
11/30/1982	16.10%	12.73%	3.37%
11/30/1982	15.50%	12.73%	2.77%
11/30/1982	15.50%	12.73%	2.77%
11/30/1982	12.98%	12.73%	0.25%
11/30/1982	15.65%	12.73%	2.92%
11/30/1982	16.00%	12.73%	3.27%
12/3/1982	15.33%	12.69%	2.64%
12/8/1982	15.75%	12.64%	3.11%
12/13/1982	16.00%	12.59%	3.41%
12/14/1982	16.40%	12.58%	3.82%
12/17/1982	16.25%	12.53%	3.72%
12/20/1982	15.00%	12.52%	2.48%
12/21/1982	15.70%	12.50%	3.20%
12/28/1982	15.25%	12.44%	2.81%
12/28/1982	15.25%	12.44%	2.81%
12/29/1982	16.25%	12.42%	3.83%
12/29/1982	16.25%	12.42%	3.83%
1/11/1983	15.90%	12.27%	3.63%
1/12/1983	15.50%	12.25%	3.25%
1/18/1983	15.00%	12.19%	2.81%
1/24/1983	16.00%	12.14%	3.86%
1/24/1983	15.50%	12.14%	3.36%
1/28/1983	14.90%	12.09%	2.81%
1/31/1983	15.00%	12.08%	2.92%
2/10/1983	15.00%	11.99%	3.01%
2/25/1983	15.70%	11.86%	3.84%
3/2/1983	15.25%	11.81%	3.44%
3/16/1983	16.00%	11.65%	4.35%
3/21/1983	14.96%	11.60%	3.36%
3/23/1983	15.40%	11.56%	3.84%
3/23/1983	16.10%	11.56%	4.54%
3/24/1983	15.00%	11.54%	3.46%
4/11/1983	13.25%	11.34%	1.91%
4/29/1983	15.05%	11.12%	3.93%
5/3/1983	15.40%	11.09%	4.31%
5/9/1983	15.50%	11.02%	4.48%
5/19/1983	14.85%	10.91%	3.94%
5/31/1983	14.00%	10.86%	3.14%
6/2/1983	14.50%	10.84%	3.66%
6/7/1983	14.50%	10.82%	3.68%
6/9/1983	14.85%	10.80%	4.05%
6/20/1983	14.15%	10.75%	3.40%
6/20/1983	16.50%	10.75%	5.75%
6/27/1983	14.50%	10.72%	3.78%
6/30/1983	14.80%	10.71%	4.09%
6/30/1983	15.90%	10.71%	5.19%
7/1/1983	14.80%	10.71%	4.09%
7/5/1983	15.00%	10.71%	4.29%
7/8/1983	15.50%	10.70%	4.80%
7/19/1983	15.10%	10.71%	4.39%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/19/1983	15.00%	10.71%	4.29%
8/18/1983	15.30%	10.81%	4.49%
8/19/1983	15.79%	10.81%	4.98%
8/29/1983	16.00%	10.85%	5.15%
8/31/1983	15.25%	10.86%	4.39%
8/31/1983	14.75%	10.86%	3.89%
9/8/1983	14.75%	10.89%	3.86%
9/16/1983	15.51%	10.92%	4.59%
9/26/1983	14.50%	10.95%	3.55%
9/28/1983	14.25%	10.96%	3.29%
9/30/1983	16.15%	10.97%	5.18%
9/30/1983	16.25%	10.97%	5.28%
10/1/1983	16.25%	10.97%	5.28%
10/13/1983	15.52%	11.02%	4.50%
10/19/1983	15.20%	11.04%	4.16%
10/26/1983	14.75%	11.06%	3.69%
10/27/1983	15.33%	11.07%	4.26%
10/27/1983	14.88%	11.07%	3.81%
11/9/1983	14.82%	11.10%	3.72%
11/9/1983	16.51%	11.10%	5.41%
11/9/1983	16.51%	11.10%	5.41%
12/1/1983	14.50%	11.16%	3.34%
12/8/1983	15.90%	11.20%	4.70%
12/9/1983	15.30%	11.20%	4.10%
12/12/1983	14.50%	11.21%	3.29%
12/12/1983	15.50%	11.21%	4.29%
12/20/1983	16.00%	11.25%	4.75%
12/20/1983	15.40%	11.25%	4.15%
12/22/1983	15.75%	11.26%	4.49%
12/29/1983	15.00%	11.29%	3.71%
12/30/1983	15.00%	11.29%	3.71%
1/10/1984	15.90%	11.33%	4.57%
1/13/1984	15.50%	11.35%	4.15%
1/18/1984	15.53%	11.37%	4.16%
1/26/1984	15.90%	11.41%	4.49%
2/14/1984	14.25%	11.50%	2.75%
2/28/1984	14.50%	11.57%	2.93%
3/20/1984	16.00%	11.69%	4.31%
3/23/1984	15.50%	11.71%	3.79%
4/8/1984	15.20%	11.80%	3.40%
4/17/1984	16.20%	11.84%	4.36%
4/26/1984	15.85%	11.89%	3.96%
5/15/1984	13.35%	11.99%	1.36%
5/16/1984	15.00%	11.99%	3.01%
5/22/1984	14.40%	12.03%	2.37%
6/13/1984	15.50%	12.18%	3.32%
7/10/1984	16.00%	12.36%	3.64%
8/7/1984	16.69%	12.50%	4.19%
8/9/1984	15.33%	12.50%	2.83%
8/17/1984	14.82%	12.53%	2.29%
8/21/1984	14.64%	12.53%	2.11%
8/27/1984	14.52%	12.55%	1.97%
8/28/1984	14.75%	12.56%	2.19%
8/30/1984	15.60%	12.57%	3.03%
9/12/1984	15.90%	12.59%	3.31%
9/12/1984	15.60%	12.59%	3.01%
9/25/1984	16.25%	12.60%	3.65%
10/2/1984	14.80%	12.62%	2.18%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/9/1984	14.75%	12.62%	2.13%
10/10/1984	15.50%	12.63%	2.87%
10/18/1984	15.00%	12.64%	2.36%
10/24/1984	15.50%	12.64%	2.86%
11/7/1984	15.00%	12.63%	2.37%
11/20/1984	15.92%	12.62%	3.30%
11/30/1984	15.50%	12.59%	2.91%
12/18/1984	15.00%	12.55%	2.45%
12/20/1984	15.00%	12.54%	2.46%
12/28/1984	15.75%	12.51%	3.24%
12/28/1984	16.25%	12.51%	3.74%
1/2/1985	16.00%	12.50%	3.50%
1/31/1985	14.75%	12.38%	2.37%
2/7/1985	14.85%	12.34%	2.51%
2/15/1985	15.00%	12.28%	2.72%
2/20/1985	14.50%	12.26%	2.24%
2/22/1985	14.86%	12.26%	2.60%
3/14/1985	15.50%	12.18%	3.32%
3/28/1985	14.80%	12.10%	2.70%
4/8/1985	15.50%	12.05%	3.45%
4/15/1985	15.70%	11.99%	3.71%
6/10/1985	15.75%	11.59%	4.16%
6/26/1985	14.82%	11.47%	3.35%
7/9/1985	15.00%	11.39%	3.61%
7/26/1985	14.50%	11.27%	3.23%
8/29/1985	14.50%	11.12%	3.38%
8/30/1985	14.38%	11.11%	3.27%
9/12/1985	15.25%	11.07%	4.18%
9/23/1985	15.30%	11.04%	4.26%
9/25/1985	14.50%	11.03%	3.47%
9/26/1985	13.80%	11.02%	2.78%
9/26/1985	14.50%	11.02%	3.48%
10/25/1985	15.25%	10.92%	4.33%
11/8/1985	12.94%	10.86%	2.08%
11/20/1985	14.90%	10.81%	4.09%
11/25/1985	13.30%	10.79%	2.51%
12/6/1985	12.00%	10.73%	1.27%
12/11/1985	14.90%	10.69%	4.21%
12/20/1985	15.00%	10.60%	4.40%
12/20/1985	14.88%	10.60%	4.28%
12/20/1985	15.00%	10.60%	4.40%
12/30/1985	15.75%	10.54%	5.21%
12/31/1985	14.00%	10.52%	3.48%
12/31/1985	14.50%	10.52%	3.98%
1/17/1986	14.50%	10.39%	4.11%
2/11/1986	12.50%	10.22%	2.28%
2/12/1986	15.20%	10.20%	5.00%
3/11/1986	14.00%	9.98%	4.02%
4/2/1986	12.90%	9.77%	3.13%
4/28/1986	13.01%	9.48%	3.53%
5/21/1986	13.25%	9.19%	4.06%
5/28/1986	14.00%	9.13%	4.87%
5/29/1986	13.90%	9.12%	4.78%
6/2/1986	13.00%	9.09%	3.91%
6/11/1986	14.00%	8.99%	5.01%
6/13/1986	13.55%	8.96%	4.59%
6/27/1986	11.88%	8.79%	3.09%
7/14/1986	12.60%	8.61%	3.99%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/30/1986	13.30%	8.41%	4.89%
8/14/1986	13.50%	8.24%	5.26%
9/5/1986	13.30%	8.04%	5.26%
9/23/1986	12.75%	7.92%	4.83%
10/30/1986	13.00%	7.69%	5.31%
10/31/1986	13.75%	7.68%	6.07%
11/10/1986	14.00%	7.63%	6.37%
11/19/1986	13.75%	7.58%	6.17%
11/25/1986	13.15%	7.55%	5.60%
12/22/1986	13.80%	7.48%	6.32%
12/30/1986	13.90%	7.47%	6.43%
1/20/1987	12.75%	7.46%	5.29%
1/23/1987	13.55%	7.47%	6.08%
1/27/1987	12.16%	7.47%	4.69%
2/13/1987	12.60%	7.47%	5.13%
2/24/1987	12.00%	7.47%	4.53%
3/30/1987	12.20%	7.46%	4.74%
3/31/1987	13.00%	7.46%	5.54%
5/5/1987	12.85%	7.60%	5.25%
5/28/1987	13.50%	7.72%	5.78%
6/15/1987	13.20%	7.80%	5.40%
6/30/1987	12.60%	7.85%	4.75%
7/10/1987	12.90%	7.88%	5.02%
7/27/1987	13.50%	7.93%	5.57%
8/25/1987	11.40%	8.08%	3.32%
9/18/1987	13.00%	8.26%	4.74%
10/20/1987	12.60%	8.53%	4.07%
10/20/1987	12.98%	8.53%	4.45%
11/12/1987	12.75%	8.66%	4.09%
11/13/1987	12.75%	8.67%	4.08%
11/24/1987	12.50%	8.72%	3.78%
12/8/1987	12.50%	8.80%	3.70%
12/22/1987	12.00%	8.89%	3.11%
12/31/1987	13.25%	8.93%	4.32%
12/31/1987	12.85%	8.93%	3.92%
1/15/1988	13.15%	8.98%	4.17%
1/20/1988	12.75%	8.98%	3.77%
1/29/1988	13.20%	8.99%	4.21%
2/4/1988	12.60%	8.98%	3.62%
3/23/1988	13.00%	8.94%	4.06%
5/27/1988	13.18%	9.02%	4.16%
6/14/1988	13.50%	9.00%	4.50%
6/17/1988	11.72%	8.99%	2.73%
6/24/1988	11.50%	8.98%	2.52%
7/1/1988	12.75%	8.96%	3.79%
7/8/1988	12.00%	8.94%	3.06%
7/18/1988	12.00%	8.92%	3.08%
7/20/1988	13.40%	8.91%	4.49%
8/8/1988	12.74%	8.90%	3.84%
9/20/1988	12.90%	8.93%	3.97%
9/26/1988	12.40%	8.93%	3.47%
9/27/1988	13.65%	8.93%	4.72%
9/30/1988	13.25%	8.94%	4.31%
10/13/1988	13.10%	8.93%	4.17%
10/21/1988	12.80%	8.93%	3.87%
10/25/1988	13.25%	8.94%	4.31%
10/26/1988	13.50%	8.94%	4.56%
10/27/1988	12.95%	8.94%	4.01%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/28/1988	13.00%	8.94%	4.06%
11/15/1988	12.00%	8.97%	3.03%
11/29/1988	12.75%	9.00%	3.75%
12/19/1988	13.00%	9.05%	3.95%
12/21/1988	12.90%	9.05%	3.85%
12/22/1988	13.50%	9.05%	4.45%
1/26/1989	12.60%	9.06%	3.54%
1/27/1989	13.00%	9.06%	3.94%
2/8/1989	13.37%	9.05%	4.32%
3/8/1989	13.00%	9.04%	3.96%
5/4/1989	13.00%	9.04%	3.96%
6/8/1989	13.50%	8.96%	4.54%
7/19/1989	11.80%	8.84%	2.96%
7/25/1989	12.80%	8.82%	3.98%
7/31/1989	13.00%	8.80%	4.20%
8/14/1989	12.50%	8.76%	3.74%
8/22/1989	12.80%	8.73%	4.07%
8/23/1989	12.90%	8.73%	4.17%
9/21/1989	12.10%	8.63%	3.47%
10/6/1989	13.00%	8.58%	4.42%
10/17/1989	12.41%	8.55%	3.86%
10/18/1989	13.25%	8.54%	4.71%
10/20/1989	12.90%	8.53%	4.37%
10/31/1989	13.60%	8.50%	5.10%
11/3/1989	12.93%	8.49%	4.44%
11/5/1989	13.20%	8.49%	4.71%
11/9/1989	12.60%	8.46%	4.14%
11/9/1989	13.00%	8.46%	4.54%
11/28/1989	12.75%	8.38%	4.37%
12/7/1989	13.25%	8.38%	4.87%
12/15/1989	13.00%	8.38%	4.62%
12/20/1989	12.90%	8.38%	4.52%
12/21/1989	12.80%	8.38%	4.42%
12/21/1989	12.90%	8.38%	4.52%
12/27/1989	12.50%	8.38%	4.12%
1/9/1990	13.00%	8.35%	4.65%
1/18/1990	12.50%	8.31%	4.19%
1/26/1990	12.10%	8.29%	3.81%
3/21/1990	12.80%	8.20%	4.60%
3/28/1990	13.00%	8.20%	4.80%
4/5/1990	12.20%	8.21%	3.99%
4/12/1990	13.25%	8.22%	5.03%
4/30/1990	12.45%	8.26%	4.19%
5/31/1990	12.40%	8.34%	4.06%
6/15/1990	13.20%	8.36%	4.84%
6/27/1990	12.90%	8.37%	4.53%
6/29/1990	13.25%	8.37%	4.88%
7/6/1990	12.10%	8.38%	3.72%
7/19/1990	11.70%	8.40%	3.30%
8/31/1990	12.50%	8.52%	3.98%
8/31/1990	12.50%	8.52%	3.98%
9/13/1990	12.50%	8.57%	3.93%
9/18/1990	12.75%	8.59%	4.16%
9/20/1990	12.50%	8.60%	3.90%
10/2/1990	13.00%	8.64%	4.36%
10/17/1990	11.90%	8.68%	3.22%
10/31/1990	12.95%	8.70%	4.25%
11/9/1990	13.25%	8.70%	4.55%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/19/1990	13.00%	8.70%	4.30%
11/21/1990	12.50%	8.70%	3.80%
11/21/1990	12.10%	8.70%	3.40%
11/28/1990	12.75%	8.70%	4.05%
11/29/1990	12.75%	8.70%	4.05%
12/18/1990	13.10%	8.67%	4.43%
12/20/1990	12.50%	8.67%	3.83%
12/21/1990	13.60%	8.67%	4.93%
12/21/1990	13.00%	8.67%	4.33%
12/21/1990	12.50%	8.67%	3.83%
1/3/1991	13.02%	8.66%	4.36%
1/16/1991	13.25%	8.64%	4.61%
1/25/1991	11.70%	8.61%	3.09%
2/15/1991	12.70%	8.56%	4.14%
2/15/1991	12.80%	8.56%	4.24%
4/3/1991	13.00%	8.51%	4.49%
4/30/1991	12.45%	8.48%	3.97%
4/30/1991	13.00%	8.48%	4.52%
6/25/1991	11.70%	8.35%	3.35%
6/28/1991	12.50%	8.34%	4.16%
7/1/1991	11.70%	8.34%	3.36%
7/19/1991	12.10%	8.31%	3.79%
7/19/1991	12.30%	8.31%	3.99%
7/22/1991	12.90%	8.31%	4.59%
8/15/1991	12.25%	8.28%	3.97%
8/29/1991	13.30%	8.26%	5.04%
9/27/1991	12.50%	8.23%	4.27%
9/30/1991	12.40%	8.23%	4.17%
10/3/1991	11.30%	8.22%	3.08%
10/9/1991	11.70%	8.21%	3.49%
10/15/1991	13.40%	8.20%	5.20%
11/1/1991	12.90%	8.19%	4.71%
11/8/1991	12.75%	8.19%	4.56%
11/26/1991	12.00%	8.18%	3.82%
11/26/1991	11.60%	8.18%	3.42%
11/27/1991	12.70%	8.18%	4.52%
12/6/1991	12.70%	8.16%	4.54%
12/10/1991	11.75%	8.16%	3.59%
12/19/1991	12.60%	8.14%	4.46%
12/19/1991	12.80%	8.14%	4.66%
12/30/1991	12.10%	8.11%	3.99%
1/22/1992	12.84%	8.05%	4.79%
1/31/1992	12.00%	8.03%	3.97%
2/20/1992	13.00%	8.00%	5.00%
2/27/1992	11.75%	7.99%	3.76%
3/18/1992	12.50%	7.95%	4.55%
5/15/1992	12.75%	7.87%	4.88%
6/24/1992	12.20%	7.85%	4.35%
6/29/1992	11.00%	7.85%	3.15%
7/14/1992	12.00%	7.83%	4.17%
7/22/1992	11.20%	7.82%	3.38%
8/10/1992	12.10%	7.79%	4.31%
8/26/1992	12.43%	7.75%	4.68%
9/30/1992	11.60%	7.72%	3.88%
10/6/1992	12.25%	7.72%	4.53%
10/13/1992	12.75%	7.71%	5.04%
10/23/1992	11.65%	7.71%	3.94%
10/28/1992	12.25%	7.71%	4.54%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/29/1992	12.75%	7.71%	5.04%
10/30/1992	11.40%	7.70%	3.70%
11/9/1992	10.60%	7.70%	2.90%
11/25/1992	12.00%	7.68%	4.32%
11/25/1992	11.00%	7.68%	3.32%
12/3/1992	11.85%	7.67%	4.18%
12/16/1992	11.90%	7.64%	4.26%
12/22/1992	12.30%	7.63%	4.67%
12/22/1992	12.40%	7.63%	4.77%
12/30/1992	12.00%	7.61%	4.39%
12/31/1992	12.00%	7.61%	4.39%
1/12/1993	12.00%	7.59%	4.41%
1/12/1993	12.00%	7.59%	4.41%
2/2/1993	11.40%	7.53%	3.87%
2/22/1993	11.60%	7.48%	4.12%
4/23/1993	11.75%	7.27%	4.48%
5/3/1993	11.75%	7.25%	4.50%
5/3/1993	11.50%	7.25%	4.25%
6/3/1993	12.00%	7.20%	4.80%
6/7/1993	11.50%	7.20%	4.30%
6/22/1993	11.75%	7.17%	4.58%
7/21/1993	11.78%	7.07%	4.71%
7/21/1993	11.90%	7.07%	4.83%
7/23/1993	11.50%	7.06%	4.44%
7/29/1993	11.50%	7.04%	4.46%
8/12/1993	10.75%	6.98%	3.77%
8/24/1993	11.50%	6.92%	4.58%
8/31/1993	11.90%	6.89%	5.01%
9/1/1993	11.25%	6.88%	4.37%
9/1/1993	11.47%	6.88%	4.59%
9/27/1993	10.50%	6.75%	3.75%
9/29/1993	11.00%	6.73%	4.27%
9/30/1993	11.60%	6.72%	4.88%
10/8/1993	11.50%	6.68%	4.82%
10/14/1993	11.20%	6.66%	4.54%
10/15/1993	11.75%	6.65%	5.10%
10/25/1993	11.55%	6.61%	4.94%
10/28/1993	11.50%	6.59%	4.91%
10/29/1993	11.25%	6.58%	4.67%
10/29/1993	10.20%	6.58%	3.62%
10/29/1993	10.10%	6.58%	3.52%
11/2/1993	10.80%	6.57%	4.23%
11/12/1993	11.80%	6.53%	5.27%
11/23/1993	12.50%	6.51%	5.99%
11/26/1993	11.00%	6.50%	4.50%
12/1/1993	11.45%	6.49%	4.96%
12/16/1993	11.20%	6.46%	4.74%
12/16/1993	10.60%	6.46%	4.14%
12/21/1993	11.30%	6.45%	4.85%
12/22/1993	11.00%	6.45%	4.55%
12/23/1993	10.10%	6.44%	3.66%
1/5/1994	11.50%	6.41%	5.09%
1/10/1994	11.00%	6.41%	4.59%
1/25/1994	12.00%	6.37%	5.63%
2/2/1994	10.40%	6.36%	4.04%
2/9/1994	10.70%	6.34%	4.36%
4/6/1994	11.24%	6.35%	4.89%
4/25/1994	11.00%	6.39%	4.61%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
6/16/1994	10.50%	6.63%	3.87%
6/23/1994	10.60%	6.67%	3.93%
7/19/1994	10.70%	6.82%	3.88%
9/29/1994	10.90%	7.19%	3.71%
9/29/1994	11.00%	7.19%	3.81%
10/7/1994	11.87%	7.25%	4.62%
10/18/1994	11.50%	7.30%	4.20%
10/18/1994	11.50%	7.30%	4.20%
10/24/1994	11.00%	7.34%	3.66%
11/22/1994	12.12%	7.51%	4.61%
11/29/1994	11.30%	7.54%	3.76%
12/1/1994	11.00%	7.56%	3.44%
12/8/1994	11.70%	7.58%	4.12%
12/8/1994	11.50%	7.58%	3.92%
12/12/1994	11.82%	7.59%	4.23%
12/14/1994	11.50%	7.60%	3.90%
12/19/1994	11.50%	7.62%	3.88%
4/19/1995	11.00%	7.71%	3.29%
9/11/1995	11.30%	7.17%	4.13%
9/15/1995	10.40%	7.14%	3.26%
9/29/1995	11.50%	7.07%	4.43%
10/13/1995	10.76%	6.99%	3.77%
11/7/1995	12.50%	6.87%	5.63%
11/8/1995	11.30%	6.86%	4.44%
11/8/1995	11.10%	6.86%	4.24%
11/17/1995	10.90%	6.81%	4.09%
11/20/1995	11.40%	6.81%	4.59%
11/27/1995	13.60%	6.77%	6.83%
12/14/1995	11.30%	6.68%	4.62%
12/20/1995	11.60%	6.66%	4.94%
1/31/1996	11.30%	6.46%	4.84%
3/11/1996	11.60%	6.40%	5.20%
4/3/1996	11.13%	6.41%	4.72%
4/15/1996	10.50%	6.41%	4.09%
4/17/1996	10.77%	6.41%	4.36%
4/26/1996	10.60%	6.41%	4.19%
5/10/1996	11.00%	6.41%	4.59%
5/13/1996	11.25%	6.41%	4.84%
7/3/1996	11.25%	6.49%	4.76%
7/22/1996	11.25%	6.54%	4.71%
10/3/1996	10.00%	6.76%	3.24%
10/29/1996	11.30%	6.83%	4.47%
11/26/1996	11.30%	6.86%	4.44%
11/27/1996	11.30%	6.86%	4.44%
11/29/1996	11.00%	6.85%	4.15%
12/12/1996	11.96%	6.84%	5.12%
12/17/1996	11.50%	6.84%	4.66%
1/22/1997	11.30%	6.83%	4.47%
1/27/1997	11.25%	6.83%	4.42%
1/31/1997	11.25%	6.83%	4.42%
2/13/1997	11.00%	6.82%	4.18%
2/13/1997	11.80%	6.82%	4.98%
2/20/1997	11.80%	6.81%	4.99%
3/27/1997	10.75%	6.79%	3.96%
4/29/1997	11.70%	6.80%	4.90%
7/17/1997	12.00%	6.77%	5.23%
10/29/1997	10.75%	6.70%	4.05%
10/31/1997	11.25%	6.70%	4.55%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/24/1997	10.75%	6.54%	4.21%
4/28/1998	10.90%	6.11%	4.79%
4/30/1998	12.20%	6.10%	6.10%
6/30/1998	11.00%	5.95%	5.05%
8/26/1998	10.93%	5.82%	5.11%
9/3/1998	11.40%	5.80%	5.60%
9/15/1998	11.90%	5.77%	6.13%
10/7/1998	11.06%	5.71%	5.35%
10/30/1998	11.40%	5.63%	5.77%
12/10/1998	12.20%	5.52%	6.68%
12/17/1998	12.10%	5.50%	6.60%
2/19/1999	11.15%	5.32%	5.83%
3/1/1999	10.65%	5.31%	5.34%
3/1/1999	10.65%	5.31%	5.34%
6/8/1999	11.25%	5.35%	5.90%
11/12/1999	10.25%	5.91%	4.34%
12/14/1999	10.50%	5.99%	4.51%
1/28/2000	10.71%	6.16%	4.55%
2/17/2000	10.60%	6.19%	4.41%
5/25/2000	10.80%	6.19%	4.61%
6/19/2000	11.05%	6.18%	4.87%
6/22/2000	11.25%	6.18%	5.07%
7/17/2000	11.06%	6.15%	4.91%
7/20/2000	12.20%	6.14%	6.06%
8/11/2000	11.00%	6.11%	4.89%
9/27/2000	11.25%	6.01%	5.24%
9/29/2000	11.16%	6.00%	5.16%
10/5/2000	11.30%	5.99%	5.31%
11/28/2000	12.90%	5.87%	7.03%
11/30/2000	12.10%	5.87%	6.23%
2/5/2001	11.50%	5.76%	5.74%
3/15/2001	11.25%	5.67%	5.58%
5/8/2001	10.75%	5.61%	5.14%
10/24/2001	11.00%	5.54%	5.46%
10/24/2001	10.30%	5.54%	4.76%
1/9/2002	10.00%	5.50%	4.50%
1/30/2002	11.00%	5.48%	5.52%
1/31/2002	11.00%	5.47%	5.53%
4/17/2002	11.50%	5.44%	6.06%
4/29/2002	11.00%	5.45%	5.55%
6/11/2002	11.77%	5.48%	6.29%
6/20/2002	12.30%	5.47%	6.83%
8/28/2002	11.00%	5.49%	5.51%
9/11/2002	11.20%	5.45%	5.75%
9/12/2002	12.30%	5.45%	6.85%
10/28/2002	11.30%	5.35%	5.95%
10/30/2002	10.60%	5.34%	5.26%
11/1/2002	12.60%	5.34%	7.26%
11/7/2002	11.40%	5.33%	6.07%
11/8/2002	10.75%	5.33%	5.42%
11/20/2002	10.00%	5.30%	4.70%
11/20/2002	10.50%	5.30%	5.20%
12/4/2002	10.75%	5.27%	5.48%
12/30/2002	11.20%	5.19%	6.01%
1/6/2003	11.25%	5.17%	6.08%
2/28/2003	12.30%	5.01%	7.29%
3/7/2003	9.96%	4.99%	4.97%
3/12/2003	11.40%	4.98%	6.42%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
3/20/2003	12.00%	4.96%	7.04%
4/3/2003	12.00%	4.93%	7.07%
5/2/2003	11.40%	4.89%	6.51%
5/15/2003	11.05%	4.87%	6.18%
6/26/2003	11.00%	4.80%	6.20%
7/1/2003	11.00%	4.79%	6.21%
7/29/2003	11.71%	4.78%	6.93%
8/22/2003	10.20%	4.82%	5.38%
9/17/2003	9.90%	4.84%	5.06%
9/25/2003	10.25%	4.85%	5.40%
10/17/2003	10.54%	4.87%	5.67%
10/22/2003	10.46%	4.87%	5.59%
10/22/2003	10.71%	4.87%	5.84%
10/30/2003	11.00%	4.88%	6.12%
10/31/2003	10.20%	4.88%	5.32%
10/31/2003	10.75%	4.88%	5.87%
11/10/2003	10.60%	4.89%	5.71%
12/9/2003	10.50%	4.93%	5.57%
12/18/2003	10.50%	4.94%	5.56%
12/19/2003	12.00%	4.94%	7.06%
12/19/2003	12.00%	4.94%	7.06%
1/13/2004	10.25%	4.95%	5.30%
1/13/2004	12.00%	4.95%	7.05%
2/9/2004	11.25%	4.98%	6.27%
3/16/2004	10.90%	5.05%	5.85%
3/16/2004	10.90%	5.05%	5.85%
5/25/2004	10.00%	5.06%	4.94%
6/2/2004	11.22%	5.07%	6.15%
6/30/2004	10.50%	5.10%	5.40%
7/8/2004	10.00%	5.10%	4.90%
7/22/2004	10.25%	5.10%	5.15%
8/26/2004	10.50%	5.10%	5.40%
8/26/2004	10.50%	5.10%	5.40%
9/9/2004	10.40%	5.10%	5.30%
9/21/2004	10.50%	5.09%	5.41%
9/27/2004	10.30%	5.09%	5.21%
9/27/2004	10.50%	5.09%	5.41%
10/20/2004	10.20%	5.08%	5.12%
11/30/2004	10.60%	5.08%	5.52%
12/8/2004	9.90%	5.08%	4.82%
12/21/2004	11.50%	5.09%	6.41%
12/22/2004	11.50%	5.09%	6.41%
12/28/2004	10.25%	5.09%	5.16%
2/18/2005	10.30%	4.95%	5.35%
3/29/2005	11.00%	4.87%	6.13%
4/13/2005	10.60%	4.84%	5.76%
4/28/2005	11.00%	4.80%	6.20%
5/17/2005	10.00%	4.77%	5.23%
6/8/2005	10.18%	4.72%	5.46%
6/10/2005	10.90%	4.71%	6.19%
7/6/2005	10.50%	4.65%	5.85%
7/19/2005	11.50%	4.64%	6.86%
8/11/2005	10.40%	4.60%	5.80%
9/19/2005	9.45%	4.54%	4.91%
9/30/2005	10.51%	4.52%	5.99%
10/4/2005	9.90%	4.52%	5.38%
10/4/2005	10.75%	4.52%	6.23%
10/14/2005	10.40%	4.52%	5.88%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/31/2005	10.25%	4.53%	5.72%
11/2/2005	9.70%	4.53%	5.17%
11/30/2005	10.00%	4.54%	5.46%
12/9/2005	9.70%	4.53%	5.17%
12/12/2005	11.00%	4.53%	6.47%
12/20/2005	10.13%	4.53%	5.60%
12/21/2005	11.00%	4.53%	6.47%
12/21/2005	10.40%	4.53%	5.87%
12/22/2005	10.20%	4.53%	5.67%
12/22/2005	11.00%	4.53%	6.47%
12/28/2005	10.00%	4.52%	5.48%
1/5/2006	11.00%	4.52%	6.48%
1/25/2006	11.20%	4.52%	6.68%
1/25/2006	11.20%	4.52%	6.68%
2/3/2006	10.50%	4.52%	5.98%
2/15/2006	9.50%	4.53%	4.97%
4/26/2006	10.60%	4.65%	5.95%
7/24/2006	9.60%	4.86%	4.74%
7/24/2006	10.00%	4.86%	5.14%
9/20/2006	11.00%	4.93%	6.07%
9/26/2006	10.75%	4.93%	5.82%
10/20/2006	9.80%	4.96%	4.84%
11/2/2006	9.71%	4.96%	4.75%
11/9/2006	10.00%	4.97%	5.03%
11/21/2006	11.00%	4.98%	6.02%
12/5/2006	10.20%	4.97%	5.23%
1/5/2007	10.40%	4.95%	5.45%
1/9/2007	11.00%	4.95%	6.05%
1/11/2007	10.90%	4.94%	5.96%
1/19/2007	10.80%	4.93%	5.87%
1/26/2007	10.00%	4.92%	5.08%
2/8/2007	10.40%	4.91%	5.49%
3/14/2007	10.10%	4.86%	5.24%
3/20/2007	10.25%	4.85%	5.40%
3/21/2007	11.35%	4.85%	6.50%
3/22/2007	10.50%	4.84%	5.66%
3/29/2007	10.00%	4.83%	5.17%
6/13/2007	10.75%	4.81%	5.94%
6/29/2007	10.10%	4.84%	5.26%
6/29/2007	9.53%	4.84%	4.69%
7/3/2007	10.25%	4.85%	5.40%
7/13/2007	9.50%	4.86%	4.64%
7/24/2007	10.40%	4.87%	5.53%
8/1/2007	10.15%	4.88%	5.27%
8/29/2007	10.50%	4.91%	5.59%
9/10/2007	9.71%	4.91%	4.80%
9/19/2007	10.00%	4.91%	5.09%
9/25/2007	9.70%	4.91%	4.79%
10/8/2007	10.48%	4.92%	5.56%
10/19/2007	10.50%	4.91%	5.59%
10/25/2007	9.65%	4.91%	4.74%
11/15/2007	10.00%	4.89%	5.11%
11/20/2007	9.90%	4.89%	5.01%
11/27/2007	10.00%	4.88%	5.12%
11/29/2007	10.90%	4.88%	6.02%
12/14/2007	10.80%	4.87%	5.93%
12/18/2007	10.40%	4.86%	5.54%
12/19/2007	9.80%	4.86%	4.94%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/19/2007	9.80%	4.86%	4.94%
12/19/2007	10.20%	4.86%	5.34%
12/21/2007	9.10%	4.86%	4.24%
1/8/2008	10.75%	4.83%	5.92%
1/17/2008	10.75%	4.81%	5.94%
1/17/2008	10.75%	4.81%	5.94%
2/5/2008	9.99%	4.78%	5.21%
2/5/2008	10.19%	4.78%	5.41%
2/13/2008	10.20%	4.76%	5.44%
3/31/2008	10.00%	4.64%	5.36%
5/28/2008	10.50%	4.53%	5.97%
6/24/2008	10.00%	4.53%	5.47%
6/27/2008	10.00%	4.52%	5.48%
7/31/2008	10.70%	4.50%	6.20%
7/31/2008	10.82%	4.50%	6.32%
8/27/2008	10.25%	4.51%	5.74%
9/2/2008	10.25%	4.50%	5.75%
9/19/2008	10.70%	4.48%	6.22%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/24/2008	10.68%	4.48%	6.20%
9/30/2008	10.20%	4.48%	5.72%
10/3/2008	10.30%	4.47%	5.83%
10/8/2008	10.15%	4.47%	5.68%
10/20/2008	10.06%	4.47%	5.59%
10/24/2008	10.60%	4.46%	6.14%
10/24/2008	10.60%	4.46%	6.14%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/21/2008	10.50%	4.42%	6.08%
11/24/2008	10.50%	4.42%	6.08%
12/3/2008	10.39%	4.37%	6.02%
12/24/2008	10.00%	4.26%	5.74%
12/26/2008	10.10%	4.24%	5.86%
12/29/2008	10.20%	4.23%	5.97%
1/13/2009	10.45%	4.14%	6.31%
2/2/2009	10.05%	4.04%	6.01%
3/9/2009	10.30%	3.90%	6.40%
3/25/2009	10.17%	3.84%	6.33%
4/2/2009	10.75%	3.81%	6.94%
5/5/2009	10.75%	3.72%	7.03%
5/15/2009	10.20%	3.71%	6.49%
5/29/2009	9.54%	3.71%	5.83%
6/3/2009	10.10%	3.71%	6.39%
6/22/2009	10.00%	3.73%	6.27%
6/29/2009	10.21%	3.74%	6.47%
6/30/2009	9.31%	3.74%	5.57%
7/17/2009	9.26%	3.75%	5.51%
7/17/2009	10.50%	3.75%	6.75%
10/16/2009	10.40%	4.08%	6.32%
10/26/2009	10.10%	4.10%	6.00%
10/28/2009	10.15%	4.11%	6.04%
10/28/2009	10.15%	4.11%	6.04%
10/30/2009	9.95%	4.12%	5.83%
11/20/2009	9.45%	4.18%	5.27%
12/14/2009	10.50%	4.24%	6.26%
12/16/2009	10.75%	4.25%	6.50%
12/17/2009	10.30%	4.25%	6.05%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/18/2009	10.40%	4.25%	6.15%
12/18/2009	10.50%	4.25%	6.25%
12/18/2009	10.40%	4.25%	6.15%
12/22/2009	10.20%	4.27%	5.93%
12/22/2009	10.40%	4.27%	6.13%
12/28/2009	10.85%	4.29%	6.56%
12/29/2009	10.38%	4.29%	6.09%
1/11/2010	10.24%	4.34%	5.90%
1/21/2010	10.33%	4.36%	5.97%
1/21/2010	10.23%	4.36%	5.87%
1/26/2010	10.40%	4.37%	6.03%
2/10/2010	10.00%	4.39%	5.61%
2/23/2010	10.50%	4.40%	6.10%
3/9/2010	9.60%	4.40%	5.20%
3/24/2010	10.13%	4.42%	5.71%
3/31/2010	10.70%	4.43%	6.27%
4/1/2010	9.50%	4.43%	5.07%
4/2/2010	10.10%	4.44%	5.66%
4/8/2010	10.35%	4.44%	5.91%
4/29/2010	9.40%	4.46%	4.94%
4/29/2010	9.19%	4.46%	4.73%
4/29/2010	9.40%	4.46%	4.94%
5/17/2010	10.55%	4.46%	6.09%
5/24/2010	10.05%	4.46%	5.59%
6/3/2010	11.00%	4.45%	6.55%
6/16/2010	10.00%	4.45%	5.55%
6/18/2010	10.30%	4.45%	5.85%
8/9/2010	12.55%	4.41%	8.14%
8/17/2010	10.10%	4.40%	5.70%
9/16/2010	10.30%	4.31%	5.99%
9/16/2010	9.60%	4.31%	5.29%
9/16/2010	10.00%	4.31%	5.69%
9/16/2010	10.00%	4.31%	5.69%
10/21/2010	10.40%	4.20%	6.20%
11/2/2010	9.75%	4.18%	5.57%
11/2/2010	9.75%	4.18%	5.57%
11/3/2010	10.75%	4.18%	6.57%
11/19/2010	10.20%	4.15%	6.05%
12/1/2010	10.00%	4.13%	5.87%
12/6/2010	9.56%	4.13%	5.43%
12/6/2010	10.09%	4.13%	5.96%
12/9/2010	10.25%	4.12%	6.13%
12/14/2010	10.33%	4.12%	6.21%
12/17/2010	10.10%	4.12%	5.98%
12/20/2010	10.10%	4.12%	5.98%
12/23/2010	9.92%	4.11%	5.81%
1/6/2011	10.35%	4.10%	6.25%
1/12/2011	10.30%	4.09%	6.21%
1/13/2011	10.30%	4.09%	6.21%
3/10/2011	10.10%	4.16%	5.94%
3/31/2011	9.45%	4.20%	5.25%
4/18/2011	10.05%	4.23%	5.82%
5/26/2011	10.50%	4.31%	6.19%
6/21/2011	10.00%	4.35%	5.65%
6/29/2011	8.83%	4.37%	4.46%
8/1/2011	9.20%	4.41%	4.79%
9/1/2011	10.10%	4.33%	5.77%
11/14/2011	9.60%	3.94%	5.66%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/13/2011	9.50%	3.77%	5.73%
12/20/2011	10.00%	3.72%	6.28%
12/22/2011	10.40%	3.71%	6.69%
1/10/2012	9.06%	3.60%	5.46%
1/10/2012	9.45%	3.60%	5.85%
1/10/2012	9.45%	3.60%	5.85%
1/23/2012	10.20%	3.53%	6.67%
1/31/2012	10.00%	3.49%	6.51%
4/24/2012	9.75%	3.16%	6.59%
4/24/2012	9.50%	3.16%	6.34%
5/7/2012	9.80%	3.14%	6.66%
5/22/2012	9.60%	3.10%	6.50%
5/24/2012	9.70%	3.09%	6.61%
6/7/2012	10.30%	3.06%	7.24%
6/15/2012	10.40%	3.05%	7.35%
6/18/2012	9.60%	3.05%	6.55%
7/2/2012	9.75%	3.04%	6.71%
10/24/2012	10.30%	2.92%	7.38%
10/26/2012	9.50%	2.92%	6.58%
10/31/2012	10.00%	2.92%	7.08%
10/31/2012	9.30%	2.92%	6.38%
10/31/2012	9.90%	2.92%	6.98%
11/1/2012	9.45%	2.92%	6.53%
11/8/2012	10.10%	2.91%	7.19%
11/9/2012	10.30%	2.91%	7.39%
11/26/2012	10.00%	2.89%	7.11%
11/28/2012	10.40%	2.88%	7.52%
11/28/2012	10.50%	2.88%	7.62%
12/4/2012	10.50%	2.87%	7.63%
12/4/2012	10.00%	2.87%	7.13%
12/20/2012	10.40%	2.84%	7.56%
12/20/2012	10.30%	2.84%	7.46%
12/20/2012	10.10%	2.84%	7.26%
12/20/2012	10.25%	2.84%	7.41%
12/20/2012	10.50%	2.84%	7.66%
12/20/2012	9.50%	2.84%	6.66%
12/26/2012	9.80%	2.83%	6.97%
2/22/2013	9.60%	2.86%	6.74%
3/14/2013	9.30%	2.89%	6.41%
3/27/2013	9.80%	2.91%	6.89%
4/23/2013	9.80%	2.95%	6.85%
5/10/2013	9.25%	2.96%	6.29%
6/13/2013	9.40%	3.01%	6.39%
6/18/2013	9.28%	3.02%	6.26%
6/18/2013	9.28%	3.02%	6.26%
6/25/2013	9.80%	3.04%	6.76%
9/23/2013	9.60%	3.32%	6.28%
11/6/2013	10.20%	3.42%	6.78%
11/13/2013	9.84%	3.44%	6.40%
11/14/2013	10.25%	3.44%	6.81%
11/22/2013	9.50%	3.46%	6.04%
12/5/2013	10.20%	3.49%	6.71%
12/13/2013	9.60%	3.52%	6.08%
12/16/2013	9.73%	3.52%	6.21%
12/17/2013	10.00%	3.52%	6.48%
12/18/2013	9.08%	3.53%	5.55%
12/23/2013	9.72%	3.54%	6.18%
12/30/2013	10.00%	3.57%	6.43%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
1/21/2014	9.65%	3.65%	6.00%
1/22/2014	9.18%	3.65%	5.53%
2/20/2014	9.30%	3.71%	5.59%
2/21/2014	9.85%	3.71%	6.14%
2/28/2014	9.55%	3.72%	5.83%
3/16/2014	9.72%	3.73%	5.99%
4/21/2014	9.50%	3.73%	5.77%
4/22/2014	9.80%	3.73%	6.07%
5/8/2014	9.59%	3.71%	5.88%
5/8/2014	9.10%	3.71%	5.39%
6/6/2014	10.40%	3.66%	6.74%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
6/12/2014	10.10%	3.66%	6.44%
7/7/2014	9.30%	3.63%	5.67%
7/25/2014	9.30%	3.61%	5.69%
7/31/2014	9.90%	3.59%	6.31%
9/4/2014	9.10%	3.51%	5.59%
9/24/2014	9.35%	3.46%	5.89%
9/30/2014	9.75%	3.45%	6.30%
10/29/2014	10.80%	3.37%	7.43%
11/6/2014	10.20%	3.35%	6.85%
11/14/2014	10.20%	3.33%	6.87%
11/14/2014	10.30%	3.33%	6.97%
11/26/2014	10.20%	3.31%	6.89%
12/3/2014	10.00%	3.29%	6.71%
1/13/2015	10.30%	3.16%	7.14%
1/21/2015	9.05%	3.13%	5.92%
1/21/2015	9.05%	3.13%	5.92%
4/9/2015	9.50%	2.88%	6.62%
5/11/2015	9.80%	2.82%	6.98%
6/17/2015	9.00%	2.79%	6.21%
8/21/2015	9.75%	2.78%	6.97%
10/7/2015	9.55%	2.82%	6.73%
10/13/2015	9.75%	2.83%	6.92%
10/15/2015	9.00%	2.83%	6.17%
10/30/2015	9.80%	2.86%	6.94%
11/19/2015	10.00%	2.89%	7.11%
12/3/2015	10.00%	2.91%	7.09%
12/9/2015	9.60%	2.91%	6.69%
12/11/2015	9.90%	2.92%	6.98%
12/18/2015	9.50%	2.93%	6.57%
1/6/2016	9.50%	2.96%	6.54%
1/6/2016	9.50%	2.96%	6.54%
1/28/2016	9.40%	2.97%	6.43%
2/10/2016	9.60%	2.95%	6.65%
2/16/2016	9.50%	2.94%	6.56%
2/29/2016	9.40%	2.92%	6.48%
4/29/2016	9.80%	2.83%	6.97%
5/5/2016	9.49%	2.82%	6.67%
6/1/2016	9.55%	2.80%	6.75%
6/3/2016	9.65%	2.79%	6.86%
6/15/2016	9.00%	2.77%	6.23%
6/15/2016	9.00%	2.77%	6.23%
9/2/2016	9.50%	2.57%	6.93%
9/23/2016	9.75%	2.52%	7.23%
9/27/2016	9.50%	2.51%	6.99%
9/29/2016	9.11%	2.51%	6.60%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/13/2016	10.20%	2.49%	7.71%
10/28/2016	9.70%	2.47%	7.23%
11/9/2016	9.80%	2.48%	7.32%
11/18/2016	10.00%	2.49%	7.51%
12/9/2016	10.10%	2.52%	7.58%
12/15/2016	9.00%	2.53%	6.47%
12/15/2016	9.00%	2.53%	6.47%
12/20/2016	9.75%	2.53%	7.22%
12/22/2016	9.50%	2.54%	6.96%
1/24/2017	9.00%	2.59%	6.41%
2/21/2017	10.55%	2.63%	7.92%
3/1/2017	9.25%	2.65%	6.60%
4/11/2017	9.50%	2.76%	6.74%
4/20/2017	8.70%	2.79%	5.91%
4/28/2017	9.50%	2.81%	6.69%
5/23/2017	9.60%	2.87%	6.73%
6/6/2017	9.70%	2.90%	6.80%
6/22/2017	9.70%	2.93%	6.77%
6/30/2017	9.60%	2.94%	6.66%
7/20/2017	9.55%	2.97%	6.58%
7/31/2017	10.10%	2.98%	7.12%
9/13/2017	9.40%	2.93%	6.47%
9/19/2017	9.70%	2.92%	6.78%
9/22/2017	11.88%	2.92%	8.96%
9/27/2017	10.20%	2.92%	7.28%
10/20/2017	9.60%	2.90%	6.70%
10/26/2017	10.20%	2.90%	7.30%
10/30/2017	10.05%	2.90%	7.15%
12/5/2017	9.50%	2.86%	6.64%
12/7/2017	9.80%	2.86%	6.94%
12/13/2017	9.25%	2.85%	6.40%
12/28/2017	9.50%	2.84%	6.66%
1/31/2018	9.80%	2.83%	6.97%
2/21/2018	9.80%	2.84%	6.96%
2/21/2018	9.80%	2.84%	6.96%
2/28/2018	9.50%	2.85%	6.65%
3/15/2018	9.00%	2.87%	6.13%
3/26/2018	10.19%	2.88%	7.31%
4/26/2018	9.50%	2.90%	6.60%
4/27/2018	9.30%	2.91%	6.39%
5/2/2018	9.50%	2.91%	6.59%
5/3/2018	9.70%	2.91%	6.79%
5/29/2018	9.40%	2.95%	6.45%
6/6/2018	9.80%	2.96%	6.84%
6/14/2018	8.80%	2.97%	5.83%
7/16/2018	9.60%	2.98%	6.62%
7/20/2018	9.40%	2.99%	6.41%
8/24/2018	9.28%	3.02%	6.26%
8/28/2018	10.00%	3.02%	6.98%
9/13/2018	10.00%	3.04%	6.96%
9/14/2018	10.00%	3.04%	6.96%
9/19/2018	9.85%	3.05%	6.80%
9/20/2018	9.80%	3.05%	6.75%
9/26/2018	9.40%	3.06%	6.34%
9/26/2018	10.20%	3.06%	7.14%
9/28/2018	9.50%	3.06%	6.44%
9/28/2018	9.50%	3.06%	6.44%
10/5/2018	9.61%	3.08%	6.53%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
10/15/2018	9.80%	3.09%	6.71%
10/26/2018	9.40%	3.11%	6.29%
10/29/2018	9.60%	3.11%	6.49%
11/1/2018	9.87%	3.11%	6.76%
11/8/2018	9.70%	3.12%	6.58%
11/8/2018	9.70%	3.12%	6.58%
12/11/2018	9.70%	3.14%	6.56%
12/12/2018	9.30%	3.14%	6.16%
12/13/2018	9.60%	3.14%	6.46%
12/19/2018	9.30%	3.14%	6.16%
12/21/2018	9.35%	3.14%	6.21%
12/24/2018	9.25%	3.14%	6.11%
12/24/2018	9.25%	3.14%	6.11%
1/4/2019	9.80%	3.14%	6.66%
1/18/2019	9.70%	3.14%	6.56%
3/14/2019	9.00%	3.12%	5.88%
3/27/2019	9.70%	3.12%	6.58%
4/30/2019	9.73%	3.11%	6.62%
5/7/2019	9.65%	3.10%	6.55%
5/21/2019	9.80%	3.10%	6.70%
9/4/2019	10.00%	2.76%	7.24%
9/26/2019	9.90%	2.69%	7.21%
10/2/2019	9.73%	2.67%	7.06%
10/2/2019	9.90%	2.67%	7.23%
10/8/2019	9.40%	2.65%	6.75%
10/15/2019	9.70%	2.62%	7.08%
10/21/2019	9.40%	2.61%	6.79%
10/31/2019	9.70%	2.58%	7.12%
10/31/2019	10.00%	2.58%	7.42%
10/31/2019	10.00%	2.58%	7.42%
10/31/2019	10.20%	2.58%	7.62%
11/7/2019	9.35%	2.56%	6.79%
11/13/2019	9.60%	2.54%	7.06%
11/13/2019	9.60%	2.54%	7.06%
12/6/2019	9.87%	2.47%	7.40%
12/11/2019	9.40%	2.46%	6.94%
12/17/2019	9.75%	2.45%	7.30%
12/18/2019	9.60%	2.45%	7.15%
12/18/2019	9.60%	2.45%	7.15%
12/19/2019	10.20%	2.44%	7.76%
12/19/2019	10.05%	2.44%	7.61%
12/19/2019	10.25%	2.44%	7.81%
12/20/2019	9.20%	2.44%	6.76%
12/26/2019	9.75%	2.43%	7.32%
1/9/2020	9.80%	2.40%	7.40%
1/15/2020	9.35%	2.38%	6.97%
1/16/2020	8.80%	2.38%	6.42%
1/24/2020	9.44%	2.35%	7.09%
2/3/2020	9.40%	2.33%	7.07%
2/17/2020	9.80%	2.29%	7.51%
2/24/2020	9.10%	2.27%	6.83%
2/25/2020	9.50%	2.27%	7.23%
2/28/2020	9.70%	2.26%	7.44%
3/25/2020	9.40%	2.15%	7.25%
3/26/2020	9.48%	2.15%	7.33%
4/21/2020	9.80%	2.02%	7.78%
5/19/2020	9.20%	1.94%	7.26%
6/16/2020	9.65%	1.87%	7.78%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
7/8/2020	9.40%	1.81%	7.59%
8/4/2020	9.50%	1.70%	7.80%
8/20/2020	9.90%	1.65%	8.25%
8/21/2020	9.35%	1.64%	7.71%
9/10/2020	9.90%	1.58%	8.32%
9/23/2020	9.60%	1.54%	8.06%
9/25/2020	9.25%	1.53%	7.72%
9/25/2020	9.25%	1.53%	7.72%
10/4/2020	9.80%	1.50%	8.30%
10/7/2020	9.70%	1.49%	8.21%
10/12/2020	9.20%	1.48%	7.72%
10/16/2020	9.40%	1.47%	7.93%
10/30/2020	9.90%	1.45%	8.45%
11/7/2020	9.60%	1.43%	8.17%
11/19/2020	9.90%	1.42%	8.48%
11/19/2020	8.80%	1.42%	7.38%
11/19/2020	8.80%	1.42%	7.38%
11/24/2020	9.80%	1.42%	8.38%
12/9/2020	9.10%	1.43%	7.67%
12/10/2020	9.40%	1.43%	7.97%
12/16/2020	9.65%	1.44%	8.21%
12/16/2020	9.38%	1.44%	7.94%
12/23/2020	10.00%	1.45%	8.55%
1/4/2021	9.95%	1.46%	8.49%
1/6/2021	9.60%	1.47%	8.13%
1/6/2021	9.40%	1.47%	7.93%
1/12/2021	9.95%	1.48%	8.47%
1/13/2021	9.67%	1.49%	8.18%
1/26/2021	9.50%	1.51%	7.99%
2/16/2021	9.80%	1.56%	8.24%
2/19/2021	9.86%	1.57%	8.29%
2/24/2021	9.25%	1.58%	7.67%
3/25/2021	10.00%	1.67%	8.33%
3/25/2021	10.00%	1.67%	8.33%
3/25/2021	10.00%	1.67%	8.33%
4/9/2021	9.70%	1.73%	7.97%
5/5/2021	9.30%	1.82%	7.48%
5/18/2021	9.40%	1.87%	7.53%
5/19/2021	8.80%	1.87%	6.93%
6/17/2021	10.24%	1.96%	8.28%
6/30/2021	9.43%	1.99%	7.44%
7/27/2021	9.54%	2.03%	7.51%
7/30/2021	9.30%	2.03%	7.27%
8/12/2021	8.80%	2.05%	6.75%
8/12/2021	8.80%	2.05%	6.75%
9/1/2021	9.40%	2.07%	7.33%
9/8/2021	9.67%	2.07%	7.60%
9/9/2021	9.85%	2.08%	7.77%
9/14/2021	9.50%	2.08%	7.42%
9/27/2021	9.40%	2.09%	7.31%
9/29/2021	9.80%	2.09%	7.71%
9/30/2021	9.70%	2.09%	7.61%
10/6/2021	9.70%	2.10%	7.60%
10/27/2021	9.37%	2.12%	7.25%
11/17/2021	9.80%	2.11%	7.69%
11/17/2021	9.60%	2.11%	7.49%
11/18/2021	9.75%	2.11%	7.64%
11/18/2021	9.00%	2.11%	6.89%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/18/2021	10.00%	2.11%	7.89%
11/18/2021	10.00%	2.11%	7.89%
11/23/2021	9.80%	2.10%	7.70%
11/30/2021	9.40%	2.09%	7.31%
12/3/2021	9.65%	2.08%	7.57%
12/9/2021	9.90%	2.07%	7.83%
12/13/2021	9.20%	2.06%	7.14%
12/28/2021	9.60%	2.04%	7.56%
12/28/2021	9.35%	2.04%	7.31%
12/28/2021	9.38%	2.04%	7.34%
1/3/2022	9.25%	2.03%	7.22%
1/6/2022	9.60%	2.02%	7.58%
1/20/2022	9.00%	2.02%	6.98%
1/21/2022	9.60%	2.02%	7.58%
3/22/2022	9.40%	2.02%	7.38%
3/22/2022	9.40%	2.02%	7.38%
4/14/2022	9.20%	2.08%	7.12%
5/19/2022	9.23%	2.23%	7.00%
5/19/2022	9.95%	2.23%	7.72%
5/19/2022	9.95%	2.23%	7.72%
6/16/2022	9.25%	2.36%	6.89%
7/7/2022	9.90%	2.45%	7.45%
7/20/2022	9.30%	2.50%	6.80%
7/27/2022	9.85%	2.53%	7.32%
8/2/2022	9.40%	2.55%	6.85%
8/17/2022	9.60%	2.61%	6.99%
8/18/2022	9.39%	2.62%	6.77%
8/23/2022	9.40%	2.64%	6.76%
9/15/2022	9.30%	2.78%	6.52%
10/10/2022	9.60%	2.93%	6.67%
10/12/2022	9.60%	2.95%	6.65%
10/24/2022	9.40%	3.03%	6.37%
10/25/2022	9.20%	3.04%	6.16%
10/27/2022	9.70%	3.06%	6.64%
10/27/2022	9.80%	3.06%	6.74%
11/3/2022	10.20%	3.11%	7.09%
11/17/2022	9.65%	3.21%	6.44%
11/30/2022	9.38%	3.28%	6.10%
12/15/2022	9.80%	3.35%	6.45%
12/21/2022	9.60%	3.37%	6.23%
12/22/2022	9.40%	3.38%	6.02%
12/22/2022	9.80%	3.38%	6.42%
12/23/2022	9.60%	3.38%	6.22%
12/29/2022	9.80%	3.41%	6.39%
12/29/2022	9.80%	3.41%	6.39%
1/19/2023	9.60%	3.4757%	6.12%
1/23/2023	9.30%	3.48%	5.82%
1/24/2023	10.25%	3.49%	6.76%
1/26/2023	9.60%	3.49%	6.11%
3/15/2023	9.80%	3.61%	6.19%
3/23/2023	9.57%	3.62%	5.95%
3/28/2023	9.50%	3.63%	5.87%
5/4/2023	9.30%	3.72%	5.58%
6/30/2023	9.50%	3.81%	5.69%
7/20/2023	9.25%	3.80%	5.45%
8/30/2023	9.90%	3.85%	6.05%
8/30/2023	9.80%	3.85%	5.95%
8/31/2023	9.40%	3.85%	5.55%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
9/20/2023	9.35%	3.90%	5.45%
9/20/2023	9.49%	3.90%	5.59%
10/5/2023	9.30%	3.95%	5.35%
10/6/2023	9.80%	3.96%	5.84%
10/12/2023	9.20%	3.99%	5.21%
10/12/2023	9.20%	3.99%	5.21%
10/25/2023	9.55%	4.05%	5.50%
10/26/2023	9.65%	4.06%	5.59%
10/26/2023	9.50%	4.06%	5.44%
11/1/2023	9.60%	4.09%	5.51%
11/3/2023	9.70%	4.10%	5.60%
11/7/2023	9.65%	4.11%	5.54%
11/9/2023	10.15%	4.12%	6.03%
11/9/2023	9.80%	4.12%	5.68%
11/9/2023	9.80%	4.12%	5.68%
11/16/2023	9.44%	4.14%	5.30%
11/16/2023	9.38%	4.14%	5.24%
11/16/2023	9.51%	4.14%	5.37%
11/16/2023	9.38%	4.14%	5.24%
12/4/2023	9.80%	4.18%	5.62%
12/14/2023	9.45%	4.20%	5.25%
12/14/2023	9.50%	4.20%	5.30%
12/15/2023	9.65%	4.20%	5.45%
12/21/2023	9.75%	4.21%	5.54%
12/22/2023	10.50%	4.21%	6.29%
1/17/2024	9.85%	4.25%	5.60%
1/31/2024	9.70%	4.28%	5.42%
3/24/2024	9.30%	4.38%	4.92%
4/8/2024	11.88%	4.41%	7.47%
4/8/2024	9.50%	4.41%	5.09%
4/8/2024	9.50%	4.41%	5.09%
4/17/2024	9.75%	4.44%	5.31%
5/13/2024	9.80%	4.48%	5.32%
6/26/2024	9.80%	4.49%	5.31%
6/28/2024	9.40%	4.48%	4.92%
7/18/2024	9.50%	4.45%	5.05%
7/23/2024	9.90%	4.44%	5.46%
7/25/2024	9.38%	4.44%	4.94%
7/31/2024	9.75%	4.43%	5.32%
8/15/2024	9.35%	4.40%	4.95%
8/15/2024	9.35%	4.40%	4.95%
9/17/2024	9.65%	4.38%	5.27%
9/18/2024	9.45%	4.38%	5.07%
9/26/2024	9.86%	4.38%	5.48%
10/1/2024	9.85%	4.38%	5.47%
10/9/2024	9.60%	4.38%	5.22%
10/17/2024	10.08%	4.38%	5.70%
10/25/2024	9.35%	4.39%	4.96%
10/25/2024	9.40%	4.39%	5.01%
10/31/2024	9.90%	4.39%	5.51%
11/6/2024	10.00%	4.40%	5.60%
11/7/2024	9.80%	4.40%	5.40%
11/7/2024	9.90%	4.40%	5.50%
11/7/2024	9.90%	4.40%	5.50%
11/18/2024	9.15%	4.40%	4.75%
11/18/2024	9.15%	4.40%	4.75%
11/20/2024	9.70%	4.40%	5.30%
11/21/2024	9.85%	4.40%	5.45%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
11/21/2024	9.60%	4.40%	5.20%
11/21/2024	9.60%	4.40%	5.20%
12/19/2024	9.70%	4.42%	5.28%
12/19/2024	9.80%	4.42%	5.38%
12/19/2024	9.80%	4.42%	5.38%
12/19/2024	9.80%	4.42%	5.38%
12/20/2024	9.80%	4.42%	5.38%
12/30/2024	9.75%	4.43%	5.32%
1/7/2025	9.80%	4.43%	5.37%
1/15/2025	9.90%	4.44%	5.46%
2/13/2025	9.60%	4.45%	5.15%
2/24/2025	9.50%	4.46%	5.04%
3/20/2025	9.75%	4.47%	5.28%
3/27/2025	9.84%	4.47%	5.37%
4/10/2025	9.90%	4.48%	5.42%
4/22/2025	9.80%	4.50%	5.30%
4/25/2025	9.95%	4.51%	5.44%
4/25/2025	9.95%	4.51%	5.44%
5/13/2025	9.80%	4.55%	5.25%
5/15/2025	9.75%	4.56%	5.19%
5/23/2025	9.50%	4.58%	4.92%
6/12/2025	9.50%	4.65%	4.85%
6/17/2025	9.80%	4.66%	5.14%
6/18/2025	9.60%	4.66%	4.94%
6/24/2025	9.55%	4.68%	4.87%
6/24/2025	9.65%	4.68%	4.97%
6/26/2025	9.79%	4.69%	5.10%
7/1/2025	9.75%	4.70%	5.05%
8/11/2025	9.75%	4.76%	4.99%
8/14/2025	9.50%	4.76%	4.74%
8/14/2025	9.50%	4.76%	4.74%
8/26/2025	9.30%	4.78%	4.52%
8/29/2025	9.60%	4.79%	4.81%
9/30/2025	9.80%	4.80%	5.00%
10/7/2025	10.30%	4.79%	5.51%
10/8/2025	9.60%	4.79%	4.81%
10/24/2025	9.50%	4.78%	4.72%
11/4/2025	9.40%	4.77%	4.63%
11/5/2025	9.32%	4.77%	4.55%
11/6/2025	9.80%	4.77%	5.03%
11/6/2025	9.80%	4.77%	5.03%
11/19/2025	9.60%	4.78%	4.82%
11/19/2025	9.60%	4.78%	4.82%
11/19/2025	9.60%	4.78%	4.82%
11/20/2025	9.65%	4.78%	4.87%
11/20/2025	9.80%	4.78%	5.02%
12/4/2025	10.00%	4.78%	5.22%
12/9/2025	9.65%	4.79%	4.86%
12/9/2025	9.85%	4.79%	5.06%
12/17/2025	9.60%	4.79%	4.81%
12/17/2025	9.85%	4.79%	5.06%
12/18/2025	9.78%	4.79%	4.99%
12/23/2025	9.80%	4.80%	5.00%

[6]	[7]	[8]	[9]
Date of Gas Rate Case	Return on Equity	30-Year Treasury Yield	Risk Premium
12/30/2025	9.50%	4.80%	4.70%
1/7/2026	9.79%	4.81%	4.98%
1/22/2026	9.40%	4.81%	4.59%
		# of Cases:	1,389

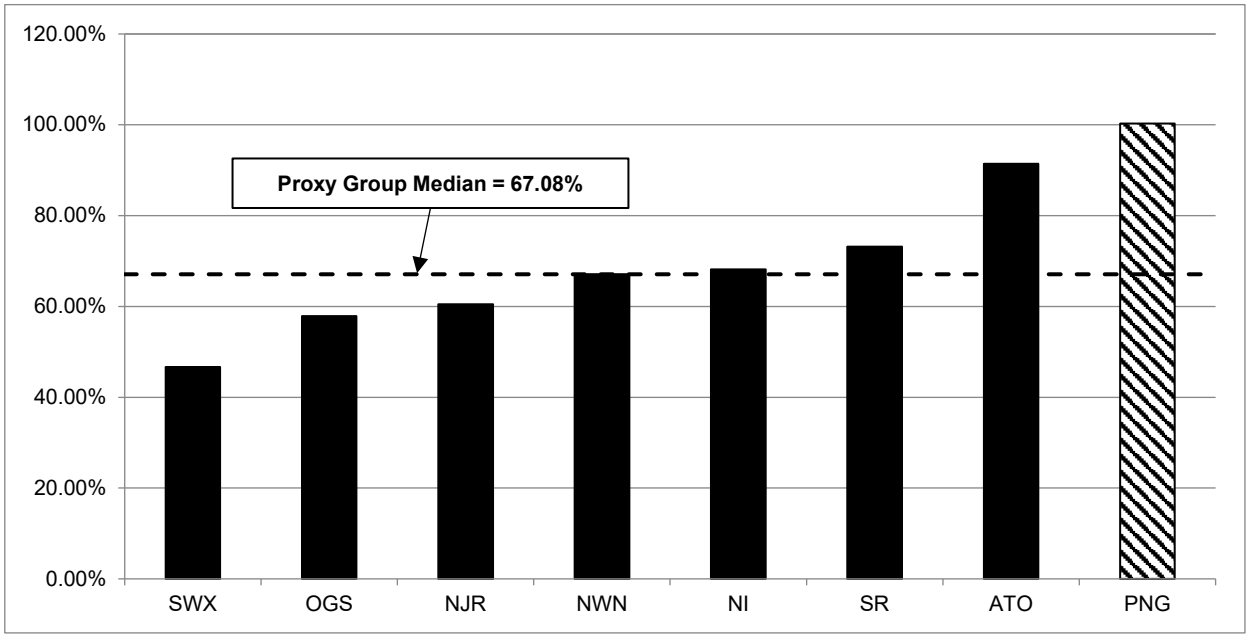
2026-2030 Capital Expenditures as a Percent of 2024 Net Plant
($ Millions)

Company	Ticker	[1] 2024	[2] 2026	[3] 2027	[4] 2028	[5] 2029	[6] 2030	[7] 2026-2030 Cap. Ex. / 2024 Net Plant
Atmos Energy Corporation	ATO							
Capital Spending per Share			$25.00	$23.30	$21.60	$21.60	$21.60	
Common Shares Outstanding			168.00	176.50	185.00	185.00	185.00	
Capital Expenditures			$4,200.0	$4,112.5	$3,996.0	$3,996.0	$3,996.0	91.43%
Net Plant		$22,204.0						
New Jersey Resources Corporation	NJR							
Capital Spending per Share			$5.75	$6.13	$6.50	$6.50	$6.50	
Common Shares Outstanding			102.00	103.50	105.00	105.00	105.00	
Capital Expenditures			$586.5	$633.9	$682.5	$682.5	$682.5	60.48%
Net Plant		$5,403.2						
NiSource Inc.	NI							
Capital Spending per Share			$6.00	$6.50	$7.00	$7.00	$7.00	
Common Shares Outstanding			500.00	512.50	525.00	525.00	525.00	
Capital Expenditures			$3,000.0	$3,331.3	$3,675.0	$3,675.0	$3,675.0	68.19%
Net Plant		$25,454.0						
Northwest Natural Holding Company	NWN							
Capital Spending per Share			$9.80	$10.05	$10.30	$10.30	$10.30	
Common Shares Outstanding			45.00	47.50	50.00	50.00	50.00	
Capital Expenditures			$441.0	$477.4	$515.0	$515.0	$515.0	67.08%
Net Plant		$3,672.3						
ONE Gas, Inc.	OGS							
Capital Spending per Share			$11.95	$11.55	$11.15	$11.15	$11.15	
Common Shares Outstanding			62.00	66.00	70.00	70.00	70.00	
Capital Expenditures			$740.9	$762.3	$780.5	$780.5	$780.5	57.85%
Net Plant		$6,645.9						
Southwest Gas Holdings, Inc.	SWX							
Capital Spending per Share			$10.30	$10.08	$9.85	$9.85	$9.85	
Common Shares Outstanding			73.00	75.00	77.00	77.00	77.00	
Capital Expenditures			$751.9	$755.6	$758.5	$758.5	$758.5	46.65%
Net Plant		$8,109.1						
Spire Inc.	SR							
Capital Spending per Share			$14.50	$13.63	$12.75	$12.75	$12.75	
Common Shares Outstanding			62.00	67.00	72.00	72.00	72.00	
Capital Expenditures			$899.0	$912.9	$918.0	$918.0	$918.0	73.13%
Net Plant		$6,243.3						
Peoples Natural Gas	PNG	2024	2026	2027	2028	2029	2030	
Capital Expenditures (2026-2030) [8]			$736.69	$783.70	$803.32	$817.32	$845.89	100.27%
Net Plant [9]		$3,976.0						

Peoples Natural Gas CapEx Total (2026 - 2030)	$3,986.9
Peoples Natural Gas CapEx Annual Average	$797.4
Proxy Group Median	67.08%
Peoples Natural Gas / Proxy Group Median	1.49

Notes:
[1] - [6] Source: Value Line company reports dated November 21, 2025
[7] Equals (Col. [2] + [3] + [4] + [5] + [6]) / Col. [1]
[8] Source: Company provided data
[9] Source: S&P Capital IQ

2026-2030 Capital Expenditures as a Percent of 2024 Net Plant



Projected CAPEX / 2024 Net Plant

Rank	Company		2026-2030
1	Southwest Gas Holdings, Inc.	SWX	46.65%
2	ONE Gas, Inc.	OGS	57.85%
3	New Jersey Resources Corporation	NJR	60.48%
4	Northwest Natural Holding Company	NWN	67.08%
5	NiSource Inc.	NI	68.19%
6	Spire Inc.	SR	73.13%
7	Atmos Energy Corporation	ATO	91.43%
8	Peoples Natural Gas	PNG	100.27%
	Proxy Group Median		67.08%
	PNG/Proxy Group		1.49

Notes:
Source: JEN-7, page 1 Col. [7]

Proxy Group Regulatory Risk Comparative Assessment

Company	Parent	Jurisdiction	Natural Gas Commodity [1]	Decoupling (F/P) [2]	New Capital Investment [3]	Energy Efficiency [4]	Other [5]	Jurisdiction Test Year Convention	Jurisdiction Rate Base Methodology	Formula-Based Rates / Annual Rate Review Mechanism
Atmos Energy	ATO	**Colorado**	✓	P	✓	✓	✓	Historical	Average	
Atmos Energy	ATO	**Kansas**	✓	P	✓		✓	Historical	Year End	
Atmos Energy	ATO	**Kentucky**	✓	P	✓	✓	✓	Historical	Year End	
Atmos Energy	ATO	**Louisiana — PSC**	✓	P	✓	✓	✓	Historical	Average	✓
Atmos Energy	ATO	**Mississippi**	✓	P	✓	✓	✓	Forecast Permitted	Average	✓
Atmos Energy	ATO	**Tennessee**	✓	P	✓		✓	Forecast	Average	✓
Atmos Energy	ATO	**Texas — RRC**	✓	P	✓	✓	✓	Historical	Year End	✓
Atmos Energy	ATO	**Virginia**	✓	P	✓			Forecast Permitted	Average	
New Jersey Natural Gas	NJR	**New Jersey**	✓	P	✓	✓	✓	Partially Forecast	Year End	
Northern Indiana Public Service Co.	NI	**Indiana**	✓	P	✓	✓	✓	Forecast Permitted	Year End	
Columbia Gas of Kentucky Inc	NI	**Kentucky**	✓	P	✓	✓	✓	Historical	Year End	
Columbia Gas of Maryland Inc.	NI	**Maryland**	✓	P	✓	✓	✓	Forecast Permitted	Average	
Columbia Gas of Ohio Inc.	NI	**Ohio**	NA	F	✓	✓	✓	Partially Forecast	Year End	
Columbia Gas of Pennsylvania Inc.	NI	**Pennsylvania**	✓	P	✓	✓	✓	Forecast	Year End	
Columbia Gas of Virginia Inc.	NI	**Virginia**	✓	F	✓	✓	✓	Forecast Permitted	Average	
Northwest Natural Gas Company	NWN	**Oregon**	✓	P	✓	✓	✓	Partially Forecast	Average	
Northwest Natural Gas Company	NWN	**Washington**	✓			✓	✓	Forecast Permitted	Average	
Kansas Gas Service	OGS	**Kansas**	✓	P	✓		✓	Historical	Year End	
Oklahoma Natural Gas	OGS	**Oklahoma**	✓	P	✓	✓	✓	Historical	Year End	✓
Texas Gas Service	OGS	**Texas — RRC**	✓	P	✓	✓	✓	Historical	Year End	
Southwest Gas Corp	SWX	**Arizona**	✓	F	✓	✓	✓	Historical	Year End	
Southwest Gas Corp	SWX	**California**	✓	F	✓	✓	✓	Forecast	Average	
Southwest Gas Corp	SWX	**Nevada**	✓	F	✓	✓	✓	Forecast Permitted	Year End	
Spire Alabama	SR	**Alabama**	✓	P	✓		✓	Historical	Year End	✓
Spire Gulf, Inc.	SR	**Alabama**	✓	P	✓		✓	Historical	Year End	✓
Spire Mississippi	SR	**Mississippi**	✓	P	✓	✓		Forecast Permitted	Average	✓
Spire Missouri - East	SR	**Missouri**	✓	P	✓		✓	Partially Forecast	Year End	
Spire Missouri - West	SR	**Missouri**	✓	P	✓		✓	Partially Forecast	Year End	
	% of Proxy Group (Op Co)		100%	96%	96%	71%	93%	57%	61%	29%
Peoples Natural Gas		Pennsylvania	✓	P	✓	✓	✓	Forecast	Year End	

Notes:

A mechanism may cover one or more cost categories; therefore, designations may not indicate separate mechanisms for each category.

[1] Columbia Gas of Ohio does not have a supply obligation for retail customers.

[2] Full or partial decoupling (such as Straight-Fixed Variable rate design, weather normalization clauses, and recovery of lost revenues as a result of Energy Efficiency programs).

[3] Includes recovery of capital costs including infrastructure replacement programs and capital/plant additions.

[4] Utility-sponsored conservation, energy efficiency, or other demand side management programs.

[5] Pension expenses, bad debt costs, storm costs, environmental costs, regulatory fee, government franchise fees and taxes, economic development, and low income assistance

Sources: Company SEC Form 10-Ks; Operating company tariffs; Regulatory Research Associates, *State Regulatory Evaluations Quarterly Update* , June 2025; Regulatory Research Associates, *Adjustment Clauses: A State-by-State Overview,* September 2025; Regulatory Research Associates, Alternative Ratemaking Frameworks in the U.S., April 16, 2020.

Flotation Cost Adjustment

Company	Date [i]	[1] Shares Issued (000)	[2] Offering Price	[3] Under-writing Discount [ii]	[4] Offering Expense ($000)	[5] Net Proceeds Per Share	[6] Total Flotation Costs ($000)	[7] Gross Equity Issue Before Costs ($000)	[8] Net Proceeds ($000)	[9] Flotation Cost Percentage
Atmos Energy Corporation	11/28/2018	8,059	$ 92.75	$ 0.98	1000	$ 91.65	$ 8,873	$ 747,500	$ 738,627	1.187%
Atmos Energy Corporation	11/28/2017	4,558	$ 88.56	$ 1.77	NA	$ 86.79	$ 8,068	$ 403,692	$ 395,624	1.999%
New Jersey Resources Corporation	12/4/2019	6,545	$ 41.25	$ 1.24	500	$ 39.94	$ 8,600	$ 270,000	$ 261,400	3.185%
NiSource Inc.	9/8/2010	24,265	$ 16.50	$ 0.54	400	$ 15.95	$ 13,411	$ 400,373	$ 386,962	3.350%
NiSource Inc.	11/6/2002	41,400	$ 18.30	$ 0.55	300	$ 17.74	$ 23,029	$ 757,620	$ 734,591	3.040%
Northwest Natural Holding Company	3/30/2022	2,875	$ 50.00	$ 1.63	450	$ 48.22	$ 5,122	$ 143,750	$ 138,628	3.563%
Northwest Natural Holding Company	6/4/2019	1,438	$ 67.00	$ 2.18	400	$ 64.54	$ 3,530	$ 96,313	$ 92,782	3.665%
ONE Gas, Inc.	5/8/2025	2,500	$ 78.76	$ 0.95	350	$ 77.67	$ 2,725	$ 196,900	$ 194,175	1.384%
ONE Gas, Inc.	9/11/2023	2,300	$ 76.18	$ 1.65	135	$ 74.47	$ 3,930	$ 175,214	$ 171,284	2.243%
Southwest Gas Holdings, Inc.	3/7/2023	4,113	$ 60.12	$ 2.03	538	$ 57.96	$ 8,883	$ 247,250	$ 238,367	3.593%
Southwest Gas Holdings, Inc.	3/28/2022	6,325	$ 74.00	$ 2.50	730	$ 71.39	$ 16,527	$ 468,050	$ 451,523	3.531%
Spire, Inc.	6/13/2023	1,745	$ 64.20	$ 0.60	450	$ 63.34	$ 1,497	$ 112,000	$ 110,503	1.336%
Spire, Inc.	5/7/2018	2,300	$ 68.75	$ 2.11	325	$ 66.50	$ 5,177	$ 158,125	$ 152,948	3.274%
Total							$ 109,371	$ 4,176,786	$ 4,067,415	
							WEIGHTED AVERAGE FLOTATION COSTS			2.62% [10]

Notes:
[i] Offering Completion Date
[ii] Underwriting discount was calculated as the market price minus the offering price when not explicitly given in the prospectus.

The flotation cost adjustment is derived by dividing the dividend yield by 1 − F (where F = flotation costs expressed in percentage terms), or by 0.9738, and adding that result to the constant growth rate to determine the cost of equity. Using the formulas shown previously in my testimony, the Constant Growth DCF calculation is modified as follows to accommodate an adjustment for flotation costs:

$$k = \frac{D \times (1 + 0.5g)}{P \times (1 - F)} + g$$

Company	Ticker	[11] Annualized Dividend	[12] Stock Price	[13] Dividend Yield	[14] Expected Dividend Yield	[15] Expected Dividend Yield Adjusted for Flotation Costs	[16] Zacks Earnings Growth	[17] CIQ Earnings Growth	[18] Value Line Earnings Growth	[19] Average Earnings Growth	[20] ROE	[21] ROE Adjusted for Flotation Costs
Atmos Energy Corporation	ATO	$4.00	$167.81	2.38%	2.48%	2.54%	6.50%	8.26%	8.50%	7.75%	10.23%	10.30%
New Jersey Resources Corporation	NJR	$1.90	$47.20	4.03%	4.18%	4.29%	n/a	8.40%	6.50%	7.45%	11.63%	11.74%
NiSource Inc.	NI	$1.12	$42.61	2.63%	2.73%	2.80%	6.00%	8.90%	8.00%	7.63%	10.36%	10.44%
Northwest Natural Holding Co.	NWN	$1.97	$46.74	4.21%	4.34%	4.46%	n/a	5.50%	6.50%	6.00%	10.34%	10.46%
ONE Gas, Inc.	OGS	$2.68	$77.89	3.44%	3.55%	3.64%	6.70%	7.10%	4.50%	6.10%	9.65%	9.74%
Southwest Gas Holdings, Inc.	SWX	$2.48	$82.09	3.02%	3.17%	3.26%	9.20%	10.50%	n/a	9.85%	13.02%	13.11%
Spire, Inc.	SR	$3.30	$83.22	3.97%	4.13%	4.24%	10.50%	9.60%	4.50%	8.20%	12.33%	12.44%
Mean											11.08%	11.17%
Flotation Cost Adjustment											[22]	0.09%

Notes:
[1] - [4] Source: SEC Form 424B2 (Prospectus)
[5] Equals [8]/[1]
[6] Equals [4] + ([1] x [3])
[7] Equals [1] x [2]
[8] Equals [7] - [6]
[9] Equals [6] / [7]
[10] Equals average [6] / average [7]
[11] Source: S&P Capital IQ
[12] Source: S&P Capital IQ, equals 30 trading day average as of 1/30/2026
[13] Equals [11] / [12]
[14] Equals [13] x (1 + 0.5 x [19])
[15] Equals [14] / (1 − Flotation Cost)
[16] Source: Zacks
[17] Source: S&P Capital IQ
[18] Source: Value Line
[19] Equals Average ([16], [17], [18])
[20] Equals [14] + [19]
[21] Equals [15] + [19]
[22] Equals Average ([21]) − Average ([20])

Peoples Natural Gas Company LLC
Investor Provided Capitalization
Actual at November 30, 2025 and Estimated at November 30, 2026 and December 31, 2027

	Actual at November 30, 2025			Estimated at November 30, 2026			Estimated at December 31, 2027		
		Ratios			Ratios			Ratios	
	Amount Outstanding	Excl. ST Debt	Incl. ST Debt	Amount Outstanding	Excl. ST Debt	Incl. ST Debt	Amount Outstanding	Excl. ST Debt	Incl. ST Debt
Long-Term Debt	$ 1,988,122,867	45.86%	45.86%	$ 2,250,004,309	45.53%	45.53%	$ 2,572,425,035	45.53%	45.53%
Common Equity									
Contributions from Members, net	$ 1,186,208,162			$ 1,290,023,037			$ 1,288,621,817		
Retained Earnings	$ 1,160,637,137			$ 1,401,980,969			$ 1,789,121,620		
Total Common Equity	$ 2,346,845,299	54.14%	54.14%	$ 2,692,004,006	54.47%	54.47%	$ 3,077,743,437	54.47%	54.47%
Total Permanent Capital	$ 4,334,968,166	100.00%	100.00%	$ 4,942,008,315	100.00%	100.00%	$ 5,650,168,471	100.00%	100.00%
Short-Term Debt	$ -		0.00%	$ -		0.00%	$ -		0.00%
Total Capital Employed	$ 4,334,968,166		100.00%	$ 4,942,008,315		100.00%	$ 5,650,168,471		100.00%

CAPITAL STRUCTURE ANALYSIS

COMMON EQUITY RATIO [1]

Proxy Group Company	Ticker	2024	2023	2022	Average
Atmos Energy Corp.	ATO	60.26%	60.20%	60.01%	60.16%
New Jersey Resources Corporation	NJR	55.92%	55.15%	53.98%	55.01%
NiSource Inc.	NI	54.89%	55.44%	54.17%	54.83%
Northwest Natural Holding Co.	NWN	49.60%	47.26%	53.27%	50.05%
ONE Gas, Inc.	OGS	58.96%	60.41%	58.24%	59.21%
Southwest Gas Holdings, Inc.	SWX	48.13%	47.45%	43.96%	46.51%
Spire, Inc.	SR	52.99%	51.91%	57.15%	54.02%
Proxy Group					
MEAN		54.39%	53.98%	54.40%	54.26%
MEDIAN		54.89%	55.15%	54.17%	54.83%
LOW		48.13%	47.26%	43.96%	46.51%
HIGH		60.26%	60.41%	60.01%	60.16%

COMMON EQUITY RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2024	2023	2022	Average
Atmos Energy Corporation	ATO	60.26%	60.20%	60.01%	60.16%
New Jersey Natural Gas Company	NJR	55.92%	55.15%	53.98%	55.01%
Columbia Gas of Kentucky, Incorporated	NI	51.44%	53.66%	54.91%	53.34%
Columbia Gas of Maryland, Incorporated	NI	52.00%	52.00%	51.96%	51.99%
Columbia Gas of Ohio, Inc.	NI	50.27%	50.50%	50.67%	50.48%
Columbia Gas of Pennsylvania, Inc.	NI	56.07%	55.88%	56.64%	56.20%
Columbia Gas of Virginia, Incorporated	NI	44.58%	45.25%	44.25%	44.69%
Northern Indiana Public Service Company, LLC	NI	58.24%	59.26%	56.92%	58.14%
Northwest Natural Gas Company	NWN	49.60%	47.26%	53.27%	50.05%
Kansas Gas Service Company, Inc.	OGS	59.53%	60.44%	58.37%	59.45%
Oklahoma Natural Gas Company	OGS	59.23%	60.46%	58.26%	59.32%
Texas Gas Service Company, Inc.	OGS	58.22%	60.35%	58.13%	58.90%
Southwest Gas Corporation	SWX	48.13%	47.45%	43.96%	46.51%
Spire Alabama Inc.	SR	55.84%	55.31%	61.18%	57.44%
Spire Gulf Inc.	SR	48.89%	46.42%	51.61%	48.97%
Spire Mississippi Inc.	SR	NA	NA	NA	NA
Spire Missouri Inc.	SR	51.95%	50.66%	55.55%	52.72%
Operating Company					
MEAN		53.76%	53.76%	54.35%	53.96%
MEDIAN		53.92%	54.40%	55.23%	54.18%
LOW		44.58%	45.25%	43.96%	44.69%
HIGH		60.26%	60.46%	61.18%	60.16%

Notes:
Sources: Operating Company Annual LDC Reports; S&P Capital IQ
[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.
[2] Spire Mississippi was excluded because it does not report long-term debt.

CAPITAL STRUCTURE ANALYSIS

LONG-TERM DEBT RATIO [1]

Proxy Group Company	Ticker	2024	2023	2022	Average
Atmos Energy Corp.	ATO	39.74%	39.80%	39.99%	39.84%
New Jersey Resources Corporation	NJR	44.08%	44.85%	46.02%	44.99%
NiSource Inc.	NI	45.11%	44.56%	45.83%	45.17%
Northwest Natural Holding Co.	NWN	50.40%	52.74%	46.73%	49.95%
ONE Gas, Inc.	OGS	41.04%	39.59%	41.76%	40.79%
Southwest Gas Holdings, Inc.	SWX	51.87%	52.55%	56.04%	53.49%
Spire, Inc.	SR	47.01%	48.09%	42.85%	45.98%
Proxy Group					
MEAN		45.61%	46.02%	45.60%	45.74%
MEDIAN		45.11%	44.85%	45.83%	45.17%
LOW		39.74%	39.59%	39.99%	39.84%
HIGH		51.87%	52.74%	56.04%	53.49%

LONG-TERM DEBT RATIO - UTILITY OPERATING COMPANIES [2]

Company Name	Ticker	2024	2023	2022	Average
Atmos Energy Corporation	ATO	39.74%	39.80%	39.99%	39.84%
New Jersey Natural Gas Company	NJR	44.08%	44.85%	46.02%	44.99%
Columbia Gas of Kentucky, Incorporated	NI	48.56%	46.34%	45.09%	46.66%
Columbia Gas of Maryland, Incorporated	NI	48.00%	48.00%	48.04%	48.01%
Columbia Gas of Ohio, Inc.	NI	49.73%	49.50%	49.33%	49.52%
Columbia Gas of Pennsylvania, Inc.	NI	43.93%	44.12%	43.36%	43.80%
Columbia Gas of Virginia, Incorporated	NI	55.42%	54.75%	55.75%	55.31%
Northern Indiana Public Service Company, LLC	NI	41.76%	40.74%	43.08%	41.86%
Northwest Natural Gas Company	NWN	50.40%	52.74%	46.73%	49.95%
Kansas Gas Service Company, Inc.	OGS	40.47%	39.56%	41.63%	40.55%
Oklahoma Natural Gas Company	OGS	40.77%	39.54%	41.74%	40.68%
Texas Gas Service Company, Inc.	OGS	41.78%	39.65%	41.87%	41.10%
Southwest Gas Corporation	SWX	51.87%	52.55%	56.04%	53.49%
Spire Alabama Inc.	SR	44.16%	44.69%	38.82%	42.56%
Spire Gulf Inc.	SR	51.11%	53.58%	48.39%	51.03%
Spire Mississippi Inc.	SR	NA	NA	NA	NA
Spire Missouri Inc.	SR	48.05%	49.34%	44.45%	47.28%
Operating Company					
MEAN		46.24%	46.24%	45.65%	46.04%
MEDIAN		46.08%	45.60%	44.77%	45.82%
LOW		39.74%	39.54%	38.82%	39.84%
HIGH		55.42%	54.75%	56.04%	55.31%

Notes:
Sources: Operating Company Annual LDC Reports; S&P Capital IQ
[1] Ratios are weighted by actual common equity and total long-term debt of operating subsidiaries.
[2] Spire Mississippi was excluded because it does not report long-term debt.

Gas Proxy Group Current Authorized Equity Ratio by Jurisdiction

Ticker	Company Name	Docket Number	Jurisdiction	Date Authorized	Current Authorized Equity Ratio	
ATO	Atmos Energy Corporation					
	Colorado Division	D-22AL-0348G	CO	5/4/2023	58.00%	
	Kansas Division	D-23-ATMG-359-RTS	KS	5/9/2023	NA	
	Kansas Division	D-19-ATMG-525-RTS	KS	2/24/2020	56.32%	
	Kentucky Division	C-2024-00276	KY	8/11/2025	53.50%	
	Louisiana Division	D-U-37754	LA	7/21/2025	58.00%	[1]
	Mississippi Division	D-2025-UN-59	MS	11/4/2025	50.00%	
	Tennessee Division	D-25-00007	TN	7/15/2025	61.05%	
	West Texas Division	OS-24-00018879 [2]	TX RRC	5/13/2025	61.00%	
	Mid-Tex (Environs)	OS-24-00019196	TX RRC	6/17/2025	60.97%	
	Mid-Tex (Cities)	[2]	TX RRC	10/1/2023	58.00%	
	Mid-Tex (Dallas)	[2]	TX RRC	6/1/2024	60.00%	
	Mid-Tex (ATM Cities)	[2]	TX RRC	6/17/2025	61.00%	
	Virginia Division	PUR-2023-00008	VA	5/13/2024	60.59%	
NI	NiSource Inc.					
	Columbia Gas of Kentucky, Incorporated	C-2024-00092	KY	12/30/2024	52.64%	
	Columbia Gas of Maryland, Incorporated	C-9754	MD	4/22/2025	52.17%	
	Columbia Gas of Ohio, Inc.	C-21-0637-GA-AIR	OH	1/26/2023	50.60%	
	Columbia Gas of Pennsylvania, Inc.	D-R-2025-3053499	PA	12/4/2025	54.40%	
	Columbia Gas of Virginia, Incorporated	C-PUR-2024-00030	VA	5/15/2025	43.16%	[3]
	Northern Indiana Public Service Company	Ca-45967	IN	7/31/2024	58.51%	[4]
NJR	New Jersey Resources Corporation					
	New Jersey Natural Gas Company	D-GR24010071	NJ	11/21/2024	54.00%	
NWN	Northwest Natural Holding Company					
	Northwest Natural Gas Company	D-UG-520	OR	10/24/2025	50.00%	
	Northwest Natural Gas Company	D-UG-200994	WA	10/21/2021	NA	
	Northwest Natural Gas Company	D-UG-181053	WA	10/21/2019	49.00%	
OGS	ONE Gas, Inc.					
	Kansas Gas Service Company, Inc.	D-24-KGSG-610-RTS	KS	10/3/2024	NA	
	Oklahoma Natural Gas Company	Ca-PUD2025-000011	OK	7/23/2025	NA	
	Oklahoma Natural Gas Company	Ca-PUD202200023	OK	11/29/2022	NA	
	Oklahoma Natural Gas Company	Ca-PUD202100063	OK	11/30/2021	58.55%	
	Texas Gas Service Company, Inc. (Central-Gulf)	D-OS-24-00017471	TX RRC	11/20/2024	59.58%	
	Texas Gas Service Company, Inc. (Rio Grande)	D-OSS-23-00014399	TX RRC	1/31/2024	59.07%	
	Texas Gas Service Company, Inc. (WTX North)	D-OSS-22-00009896	TX RRC	1/19/2023	59.74%	
SR	Spire Inc.					[5]
	Spire Alabama Inc.	D-18328	AL	9/30/2022	55.50%	
	Spire Missouri Inc.	C-GR-2025-0107	MO	9/3/2025	NA	
	Spire Missouri Inc.	C-GR-2021-0108	MO	10/27/2021	49.86%	
	Spire Mississippi	D-2015-UN-109	MS	12/2/2022	50.00%	
	Spire Gulf Inc.	D-28101	AL	9/30/2021	55.50%	
SWX	Southwest Gas Holdings Inc.					
	Arizonia Division	D-G-G-01551A-23-0341	AZ	3/27/2025	48.50%	
	California Division (SoCal)	A-19-08-015 (SoCal)	CA	3/25/2021	52.00%	
	California Division (NoCal)	A-19-08-015 (NoCal)	CA	3/25/2021	52.00%	
	California Division (LkTah)	A-19-08-015 (LkTah)	CA	3/25/2021	52.00%	
	Nevada Division (Northern)	D-23-09012 (Northern)	NV	4/8/2024	50.00%	
	Nevada Division (Southern)	D-23-09012 (Southern)	NV	4/8/2024	50.00%	
	Average				54.72%	
	Median				54.40%	
	High				61.05%	
	Low				43.16%	
	Count≥54.00%				19	
	Total Count				35	
	Percentage≥54.00%				54%	

Source: Regulatory Research Associates; SEC Form 10-K for ATO and SR
If the capital structure was not determined in the most recent rate proceeding, the authorized equity ratio determined in the next most recent proceeding with a determination was used.

Notes:

[1] Atmos' Louisiana jurisdiction is authorized through rate stabilization clause (RSC) proceedings, not a general rate case

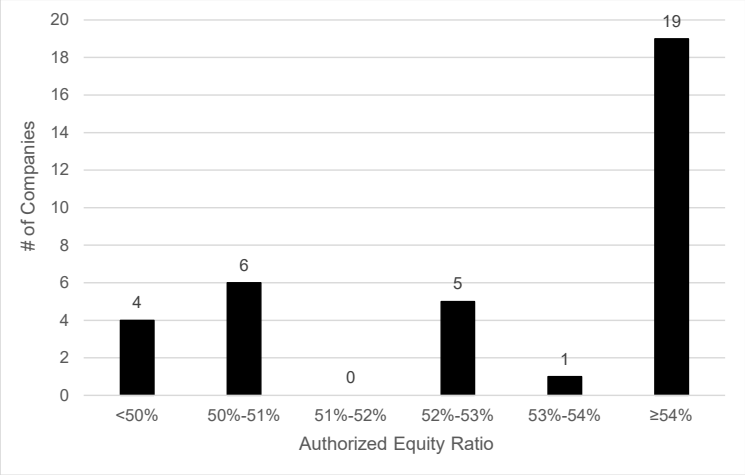
[2] Gas utilities regulated by the Texas Rail Road Commission (RRC) have a general rate case only if they are unable to reach a settlement with the cities and unincorporated areas ("environs") within their service territories. Current authorized equity ratio for Atmos Texas' territories is published in ATO's December 2025 Investor Presentation and 2024 10-K.

[3] Calculated using investor-supplied capital sources only. Columbia Gas of Virginia's authorized capital structure includes 7.316% short-term debt, 47.348% long-term debt, 2.166% preferred stock, 43.147% common equity and 0.023% Job Development Credits.

[4] Calculated using investor-supplied capital sources only. Indiana includes non-investor supplied capital in the ratemaking capital structure reported by RRA. Including non-investor supplied capital, NIPSCO's authorized equity ratio is 52.39%

[5] Source: Spire, Inc. 2025 Investor Presentation and 2024 10-K; authorized equity ratios in Spire's AL and MS jurisdictions are authorized through rate stabilization proceedings, not general rate cases

Equity Ratio	Count
<50%	4
50%-51%	6
51%-52%	0
52%-53%	5
53%-54%	1
≥54%	19



Peoples Natural Gas Company LLC
Calculation of the Embeded Costs of Long Term Debt

Actual at 11/30/2025

Series	Principal Amount Outstanding	Percent to Total	Effective Cost Rate (1)	Weighted Cost Rate
2013 Intercompany Promissory Note, Tranche 3	$ 110,007,200	5.53%	4.30%	0.24%
2017 Intercompany Promissory Note, Tranche 2	178,911,000	9.00%	3.47%	0.31%
2017 Intercompany Promissory Note, Tranche 3	178,911,000	9.00%	3.70%	0.33%
2022 Intercompany Promissory Note, Tranche 1	183,149,854	9.21%	2.80%	0.26%
2022 Intercompany Promissory Note, Tranche 2	219,779,827	11.05%	3.41%	0.38%
2022 Intercompany Promissory Note, Tranche 7	65,364,587	3.29%	2.51%	0.08%
2022 Intercompany Promissory Note, Tranche 8	81,705,732	4.11%	5.43%	0.22%
2022 Intercompany Promissory Note, Tranche 1	38,636,364	1.94%	2.80%	0.05%
2022 Intercompany Promissory Note, Tranche 2	46,363,636	2.33%	3.41%	0.08%
2023 Intercompany Promissory Note, Tranche 1	152,444,444	7.67%	2.51%	0.19%
2023 Intercompany Promissory Note, Tranche 2	190,555,556	9.58%	5.41%	0.52%
2024 Intercompany Promissory Note, Tranche 1	48,839,507	2.46%	2.54%	0.06%
2024 Intercompany Promissory Note, Tranche 2	61,049,382	3.07%	5.46%	0.17%
2025 Intercompany Promissory Note, Tranche 1	148,500,000	7.47%	5.50%	0.41%
Intercompany Demand Note	283,904,778	14.28%	4.97% (2)	0.71%
Long Term Debt	$ 1,988,122,867	100.00%		4.02%
Long Term Debt	$ 1,988,122,867	100.00%	4.02%	4.02%
Short Term Debt	$ -	0.00%	4.97% (2)	0.00%
TOTAL	$ 1,988,122,867	100.00%		4.02%

Peoples Natural Gas Company LLC
Calculation of the Embeded Costs of Long Term Debt

Estimated at 11/30/2026

Series	Principal Amount Outstanding	Percent to Total	Effective Cost Rate	Weighted Cost Rate
2013 Intercompany Promissory Note, Tranche 3	$ -	0.00%	4.30%	0.00%
2017 Intercompany Promissory Note, Tranche 2	178,911,000	7.95%	3.47%	0.28%
2017 Intercompany Promissory Note, Tranche 3	178,911,000	7.95%	3.70%	0.29%
2022 Intercompany Promissory Note, Tranche 1	183,149,854	8.14%	2.80%	0.23%
2022 Intercompany Promissory Note, Tranche 2	219,779,827	9.77%	3.41%	0.33%
2022 Intercompany Promissory Note, Tranche 7	65,364,587	2.91%	2.51%	0.07%
2022 Intercompany Promissory Note, Tranche 8	81,705,732	3.63%	5.43%	0.20%
2022 Intercompany Promissory Note, Tranche 1	38,636,364	1.72%	2.80%	0.05%
2022 Intercompany Promissory Note, Tranche 2	46,363,636	2.06%	3.41%	0.07%
2023 Intercompany Promissory Note, Tranche 1	152,444,444	6.78%	2.51%	0.17%
2023 Intercompany Promissory Note, Tranche 2	190,555,556	8.47%	5.41%	0.46%
2024 Intercompany Promissory Note, Tranche 1	48,839,507	2.17%	2.54%	0.06%
2024 Intercompany Promissory Note, Tranche 2	61,049,382	2.71%	5.46%	0.15%
2025 Intercompany Promissory Note, Tranche 1	148,500,000	6.60%	5.50%	0.36%
2025 Intercompany Promissory Note, Tranche 2	61,409,190	2.73%	5.49%	0.15%
2025 Intercompany Promissory Note, Tranche 2	323,735,810	14.39%	5.39%	0.78%
2026 Intercompany Promissory Note, Tranche 1	129,000,000	5.73%	5.50%	0.32%
2026 Intercompany Promissory Note, Tranche 2	166,000,000	7.38%	5.50%	0.41%
Intercompany Demand Note	(24,351,580)	-1.08%	4.40% (3)	-0.05%
Long Term Debt	$ 2,250,004,309	100.00%		4.31%
Long Term Debt	$ 2,250,004,309	100.00%	4.31%	4.31%
Short Term Debt	$ -	0.00%	4.40% (3)	0.00%
TOTAL	$ 2,250,004,309	100.00%		4.31%

Peoples Natural Gas Company LLC
Calculation of the Embeded Costs of Long Term Debt

Estimated at 12/31/2027

Series	Principal Amount Outstanding	Percent to Total	Effective Cost Rate	Weighted Cost Rate
2017 Intercompany Promissory Note, Tranche 2	-	0.00%	3.47%	0.00%
2017 Intercompany Promissory Note, Tranche 3	178,911,000	6.95%	3.70%	0.26%
2022 Intercompany Promissory Note, Tranche 1	183,149,854	7.12%	2.80%	0.20%
2022 Intercompany Promissory Note, Tranche 2	219,779,827	8.54%	3.41%	0.29%
2022 Intercompany Promissory Note, Tranche 7	65,364,587	2.54%	2.51%	0.06%
2022 Intercompany Promissory Note, Tranche 8	81,705,732	3.18%	5.43%	0.17%
2022 Intercompany Promissory Note, Tranche 1	38,636,364	1.50%	2.80%	0.04%
2022 Intercompany Promissory Note, Tranche 2	46,363,636	1.80%	3.41%	0.06%
2023 Intercompany Promissory Note, Tranche 1	152,444,444	5.93%	2.51%	0.15%
2023 Intercompany Promissory Note, Tranche 2	190,555,556	7.41%	5.41%	0.40%
2024 Intercompany Promissory Note, Tranche 1	48,839,507	1.90%	2.54%	0.05%
2024 Intercompany Promissory Note, Tranche 2	61,049,382	2.37%	5.46%	0.13%
2025 Intercompany Promissory Note, Tranche 1	148,500,000	5.77%	5.50%	0.32%
2025 Intercompany Promissory Note, Tranche 2	61,409,190	2.39%	5.49%	0.13%
2025 Intercompany Promissory Note, Tranche 2	323,735,810	12.58%	5.39%	0.68%
2026 Intercompany Promissory Note, Tranche 1	129,000,000	5.01%	5.50%	0.28%
2026 Intercompany Promissory Note, Tranche 2	166,000,000	6.45%	5.50%	0.35%
2027 Intercompany Promissory Note, Tranche 1	137,000,000	5.33%	5.57%	0.30%
2027 Intercompany Promissory Note, Tranche 2	339,980,146	13.22%	5.57%	0.74%
Intercompany Demand Note	(0)	0.00%	4.30% (3)	0.00%
Long Term Debt	$ 2,572,425,035	100.00%		4.61%
Long Term Debt	$ 2,572,425,035	100.00%	4.61%	4.61%
Short Term Debt	$ -	0.00%	4.30% (3)	0.00%
TOTAL	$ 2,572,425,035	100.00%		4.61%

Notes:
(1) As Calculated on Page 4 of this Schedule
(2) Actual Rate at 11/30/2025
(3) Represents projected SOFR rate plus margin of 1.00%

Sources: Company provided data; Blue Chip Financial Forecasts; Bloomberg Professional

Peoples Natural Gas Company LLC
Calculation of the Effective Cost of Long Term Debt by Series

Series	Coupon Rate	Date of Issue	Date of Maturity	Average Term in Years	Principal Amount Issued	Discount and Expenses	Net Proceeds	Net Proceeds Ratio	Effective Cost Rate
2013 Intercompany Promissory Note, Tranche 3	4.25%	12/19/2013	12/19/2025	12	$ 110,007,200	$ 523,077	$ 109,484,123	99.52%	4.30%
2017 Intercompany Promissory Note, Tranche 2	3.38%	12/18/2017	12/18/2027	10	$ 178,911,000	$ 1,338,539	$ 177,572,461	99.25%	3.47%
2017 Intercompany Promissory Note, Tranche 3	3.63%	12/18/2017	12/18/2032	15	$ 178,911,000	$ 1,340,456	$ 177,570,544	99.25%	3.70%
2022 Intercompany Promissory Note, Tranche 1	2.70%	10/31/2021	4/15/2030	8	$ 183,149,854	$ 1,334,416	$ 181,815,438	99.27%	2.80%
2022 Intercompany Promissory Note, Tranche 2	3.35%	10/31/2021	4/15/2050	28	$ 219,779,827	$ 2,272,105	$ 217,507,722	98.97%	3.41%
2022 Intercompany Promissory Note, Tranche 7	2.40%	12/31/2021	5/1/2031	9	$ 65,364,587	$ 618,896	$ 64,745,691	99.05%	2.51%
2022 Intercompany Promissory Note, Tranche 8	5.30%	12/31/2021	5/1/2052	30	$ 81,705,732	$ 1,621,181	$ 80,084,551	98.02%	5.43%
2022 Intercompany Promissory Note, Tranche 1	2.70%	12/31/2023	4/15/2030	6	$ 38,636,364	$ 288,944	$ 38,347,420	99.25%	2.83%
2022 Intercompany Promissory Note, Tranche 2	3.35%	12/31/2023	4/15/2050	26	$ 46,363,636	$ 483,062	$ 45,880,574	98.96%	3.41%
2023 Intercompany Promissory Note, Tranche 1	2.40%	12/31/2023	5/1/2031	7	$ 152,444,444	$ 1,084,290	$ 151,360,154	99.29%	2.51%
2023 Intercompany Promissory Note, Tranche 2	5.30%	12/31/2023	5/1/2052	28	$ 190,555,556	$ 3,149,448	$ 187,406,108	98.35%	5.41%
2024 Intercompany Promissory Note, Tranche 1	2.40%	7/31/2024	5/1/2031	7	$ 48,839,507	$ 427,408	$ 48,412,099	99.12%	2.54%
2024 Intercompany Promissory Note, Tranche 2	5.30%	7/31/2024	5/2/2052	28	$ 61,049,382	$ 1,387,828	$ 59,661,554	97.73%	5.46%
2025 Intercompany Promissory Note, Tranche 1	5.38%	1/2/2025	1/15/2034	9	$ 148,500,000	$ 1,344,240	$ 147,155,760	99.09%	5.50%
Intercompany Demand Note, Capex Portion	4.97%				$ 283,904,778	$ -	$ 283,904,778		4.97%
2025 Intercompany Promissory Note, Tranche 2	5.38%	12/31/2025	1/15/2034	8	$ 61,409,190	$ 456,309	$ 60,952,881	99.26%	5.49%
2025 Intercompany Promissory Note, Tranche 2	5.25%	12/31/2025	8/15/2035	10	$ 323,735,810	$ 3,324,481	$ 320,411,329	98.97%	5.39%
2026 Intercompany Promissory Note, Tranche 1	5.33%	7/31/2026	7/31/2038	12	$ 129,000,000	$ 1,935,000	$ 127,065,000	98.50%	5.50%
2026 Intercompany Promissory Note, Tranche 2	5.33%	12/31/2026	12/31/2038	12	$ 166,000,000	$ 2,490,000	$ 163,510,000	98.50%	5.50%
2027 Intercompany Promissory Note, Tranche 1	5.40%	7/31/2027	7/31/2039	12	$ 137,000,000	$ 2,055,000	$ 134,945,000	98.50%	5.57%
2027 Intercompany Promissory Note, Tranche 2	5.40%	12/31/2027	12/31/2039	12	$ 339,980,146	$ 5,099,702	$ 334,880,444	98.50%	5.57%

Notes:
(1) The effective cost for each issue is the yield to maturity ("ytm") using as inputs the average term of the issue, the coupon rate and the net proceeds ratio.

PEOPLES STATEMENT NO. 16

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
	:	
vs.	:	Docket No. R-2026-3060855
	:	
	:	
Peoples Natural Gas Company, LLC	:	

DIRECT TESTIMONY OF

JOHN J. SPANOS

ON BEHALF OF

PEOPLES NATURAL GAS COMPANY, LLC

March 27, 2026

Q. PLEASE STATE YOUR NAME AND ADDRESS.

A. John J. Spanos. My business address is 300 Sterling Parkway, Mechanicsburg, Pennsylvania (formerly 207 Senate Avenue, Camp Hill, Pennsylvania).

Q. WITH WHAT FIRM ARE YOU ASSOCIATED AND IN WHAT CAPACITY?

A. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC ("Gannett Fleming"), a subsidiary of GFT Infrastructure, Inc. as President.

Q. HOW LONG HAVE YOU BEEN ASSOCIATED WITH GANNETT FLEMING?

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

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 of Pennsylvania.

Q. ARE YOU A MEMBER OF ANY PROFESSIONAL SOCIETIES?

A. Yes. I am a member and past President of the Society of Depreciation Professionals. I am also 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. WILL YOU OUTLINE YOUR EXPERIENCE IN THE FIELD OF DEPRECIATION?

A. I have over 39 years of depreciation experience which includes giving expert testimony in more than 510 cases before 47 regulatory commissions, including the Pennsylvania Public Utility Commission ("Commission"). My participation in the cases where I appeared as an expert witness has included conducting and analyzing depreciation studies for companies, government-owned utilities and other service providers in the electric, gas, water, wastewater and pipeline industries. In addition to the cases in which I submitted testimony, I have supervised over 900 other depreciation or valuation assignments. Please refer to Appendix A for additional information on my qualifications, work history, case experience, and my leadership in the Society of Depreciation Professionals.

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the gas plant of the Peoples Natural Gas Company LLC ("Peoples" or the "Company").

Q. HAVE YOU PREPARED EXHIBITS PRESENTING THE RESULTS OF YOUR STUDIES?

A. Yes, I have prepared three exhibits, consisting of the following: Exhibit Nos. 5A, 5B, and 5C present the results of the depreciation studies for the gas operations as of November 30, 2025, November 30, 2026 and December 31, 2027.

In addition, I am responsible for the responses to Depreciation Data Filing Requirements FR Sch 4, FR Sch 5, FR Sch 6, FR Sch 7 and FR Sch 8 that are presented as Exhibit No. 8 and FR Sch 1, FR Sch 2, FR Sch 3, FR Sch 4, FR Sch 5 and FR Sch 6 that are presented as Exhibit No. 9.

Q. PLEASE DESCRIBE WHAT IS SET FORTH IN EACH OF THE EXHIBIT NOS. 5.

A. Exhibit No. 5A, titled "2025 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2025," includes the results of the depreciation study related to the assets as of November 30, 2025. The report also includes the detailed depreciation calculations. Exhibit No. 5B, titled "2026 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2026," includes the results of the depreciation study related to the assets estimated as of November 30, 2026. The report also includes explanatory text, statistics related to the estimation of service life, and the detailed depreciation calculations. Exhibit No. 5C, titled "2027 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2027," includes the results of the depreciation study related to the assets estimated as of December 31, 2027.

Q. WHAT WERE THE PURPOSES OF YOUR DEPRECIATION STUDIES?

A. The purposes of the depreciation studies were to estimate the annual depreciation accruals

related to gas plant in service for ratemaking purposes and, using Commission-approved procedures, to estimate the Company's book reserve as of November 30, 2025, November 30, 2026 and December 31, 2027.

Q. IS THE COMPANY'S CLAIM FOR ANNUAL DEPRECIATION IN THE CURRENT PROCEEDING BASED ON THE SAME METHODS OF DEPRECIATION WHICH WERE USED IN ITS MOST RECENT ANNUAL DEPRECIATION REPORTS FILED IN JUNE 2025?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation, which has been used for over thirty years. For Accounts 391.01, 391.02, 391.03, 393, 394, 394.01, 397.02, 397.03, 397.10, 397.20 and 398, the claim is based on the straight line remaining life method of amortization. The accounts have a large number of units, but small asset values representing slightly more than 1 percent of the depreciable plant. The assets represent items located in office buildings, service centers, garages and warehouses. Given the difficulty in maintaining accounting records for these numerous assets and high cost for periodic inventories, retirements are recorded when a vintage is fully amortized, rather than as the units are removed from service. All units are retired when the age of the vintage reaches the amortization period. The annual amortization is based on amortization accounting which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

Q. WHAT GROUP PROCEDURE IS BEING USED IN THIS PROCEEDING FOR DEPRECIABLE ACCOUNTS?

A. The average service life procedure is used in the current proceeding for plant installed prior to 1983 and the equal life group procedure for 1983 and subsequent vintages. These calculations have been used in the same manner for the Company's most recent annual depreciation reports.

Q. IS THE COMPANY'S CLAIM FOR ACCRUED DEPRECIATION IN THE CURRENT PROCEEDING MADE ON THE SAME BASIS AS HAS BEEN USED FOR OVER THIRTY YEARS?

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

Q. HOW WAS THE BOOK RESERVE USED IN THE CALCULATION OF ANNUAL DEPRECIATION?

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

Q. HOW WAS THE BOOK RESERVE AS OF NOVEMBER 30, 2026, ESTIMATED?

A. The book reserve as of November 30, 2026, by account, was projected by adding estimated accruals, gross salvage and the amortization of net salvage, and subtracting estimated retirements and cost of removal from the book reserve as of November 30, 2025. Annual accruals were estimated using the annual accruals calculated as of November 30, 2025. For most accounts, gross salvage and cost of removal were estimated by: (1) expressing actual

gross salvage and cost of removal as a percent of retirements by account, for the most recent five-year period, and (2) applying those percents to the projected retirements by account.

For the purpose of calculating the annual accruals, the projected book reserve by account was allocated to vintages based on calculated accrued depreciation as of November 30, 2026.

Q. WAS THE BOOK RESERVE AS OF DECEMBER 31, 2027, ESTIMATED USING THE SAME METHODOLOGY?

A. Yes.

Q. HAS A SERVICE LIFE STUDY OF THE COMPANY'S GAS UTILITY PROPERTY BEEN PERFORMED?

A. Yes. A service life study was performed as of December 2022. The service life study was the basis for the service lives I used to calculate annual accruals. The service life study was used for Exhibit No. 5.

Q. BRIEFLY OUTLINE THE PROCEDURE USED IN PERFORMING THE SERVICE LIFE STUDY.

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

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

Q. WHAT STATISTICAL DATA WERE EMPLOYED IN THE HISTORICAL ANALYSES PERFORMED FOR THE PURPOSE OF ESTIMATING SERVICE LIFE CHARACTERISTICS?

A. The data consisted of the entries made to record retirements and other transactions related to the gas plant during the period 1939-2022. The year 1939 is the first year continuing property records were maintained.

These entries were classified by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed. Types of transactions included in the data were plant additions, retirements, transfers, and balances. In the presentation of service life statistics, only the significant exposure points that were utilized in determining survivor curves were plotted. This process is utilized to show my judgment in service life determinations.

Q. WHAT WAS THE SOURCE OF THESE DATA?

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

Q. WERE THE METHODS USED IN THE SERVICE LIFE STUDY THE SAME AS

THOSE USED IN OTHER DEPRECIATION STUDIES FOR GAS UTILITY PLANT PRESENTED BEFORE THIS COMMISSION?

A. Yes. The methods are the same ones that have been presented previously for Peoples Natural Gas Company LLC and for other gas companies before the Commission and that have been accepted by the Commission in its past orders concerning gas utilities.

Q. WERE THERE ANY NEW ASSET CLASSES INCLUDED IN THE STUDIES?

A. Yes. Since the last service life study was performed, the Company has added new technology meters identified as Intelis meters. These assets are in Account 381.20, Meters – Intelis and have a survivor curve of 20-S2. Based on the technology of the meters and how the meters will be utilized, the average life of 20 years is consistent with Company plans and others in the industry that have these types of meters.

Q. WHAT APPROACH DID YOU USE TO ESTIMATE THE LIVES OF SIGNIFICANT STRUCTURES SUCH AS OFFICE BUILDINGS AND SERVICE CENTERS?

A. I used the life span technique to estimate the lives of significant structures. In this technique, the survivor characteristics of the structures are described by the use of interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the structure such as plumbing, heating, doors, windows, roofs, etc. that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the structure by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves

truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation inasmuch as concurrent retirement of all years of installation will occur when the structure is retired.

Q. HAS YOUR FIRM USED THIS APPROACH IN OTHER PROCEEDINGS BEFORE THIS COMMISSION?

A. Yes, we have used the life span technique on many occasions before the Commission.

Q. WHAT ARE THE BASES FOR THE PROBABLE RETIREMENT YEARS THAT YOU HAVE ESTIMATED FOR EACH STRUCTURE?

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

Q. ARE THE FACTORS CONSIDERED IN YOUR ESTIMATES OF SERVICE LIFE PRESENTED IN EXHIBIT NO. 5B?

A. Yes. A discussion of the factors considered in the estimation of service lives is presented in Part III of the exhibit.

Q. PLEASE OUTLINE THE CONTENTS OF EXHIBIT NOS. 5B.

A. Exhibit Nos. 5B, is presented in eight parts. Part I, Introduction, sets forth the scope and basis of the study. Part II, Estimation of Survivor Curves, includes a description of the Iowa Curves and the formulation of the retirement rate method. Part III, Service Life Considerations, and Part IV, Calculation of Annual and Accrued Depreciation, include a description of the judgment utilized for life parameters and the explanation of depreciation procedures. Part V, Results of Study, presents a description of the results and summaries of the depreciation calculations. Part VI, Service Life Statistics, presents the graphs and tables which relate to the service life study. Part VII, Detailed Depreciation Calculations, sets forth the detailed depreciation calculations by account. Part VIII, Experienced and Estimated Net Salvage, presents the cost of removal and gross salvage by account for the years 2021 through 2025. For Exhibit No. 5B, Table 1, pages V-4 through V-6 presents the estimated survivor curve, the original cost as of November 30, 2026, and the book reserve and calculated annual depreciation for each account or subaccount of Gas Plant. Table 2, pages V-7 and V-8 presents the bringforward to November 30, 2026, of the book depreciation reserve as of November 30, 2025. Table 3 on pages V-9 and V-10 sets forth the calculation of the annual accruals used in the bringforward. Table 4, page V-11, presents the experienced and estimated net salvage during the five-year period, 2021 through 2025. The section beginning on page VI-1 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VII-1 presents the depreciation calculations related to original cost. The tabulation on pages VII-3 through VII- 5 presents the cumulative depreciated original cost by year installed. The tabulations on pages VII-7 through VII-122 present the calculation

of annual depreciation by vintage by account for each depreciable group of utility plant. The tabulation on pages VIII-2 through VIII-4 presents the retirements, gross salvage, and cost of removal by account for each year during the period 2021 through 2025.

Q. PLEASE OUTLINE THE CONTENTS OF EXHIBIT NO. 5C.

A. Exhibit No. 5C includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of December 31, 2027. The descriptions and explanations presented in Exhibit No. 5B are also applicable to the depreciation calculations presented in Exhibit No. 5C. The graphs and tables related to service life presented in Exhibit No. 5B, also support the service life estimates used in Exhibit No. 5C inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of December 31, 2027, are organized and presented in the same manner as those as of November 30, 2026.

Q. PLEASE OUTLINE THE CONTENTS OF EXHIBIT NOS. 5A.

A. Exhibit No. 5A includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of November 30, 2025. The descriptions and explanations presented in Exhibit No. 5B are also applicable to the depreciation calculations presented in Exhibit No. 5A. The graphs and tables related to service life presented in Exhibit No. 5B also support the service life estimates used in Exhibit No. 5A, inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of November 30, 2025, are organized and presented in the same manner as those as of November 30, 2026.

Q. PLEASE USE AN EXAMPLE TO ILLUSTRATE THE MANNER IN WHICH THE STUDIES ARE AS PRESENTED IN EXHIBIT NO. 5B.

A. I will use Account 380, Services, as my example, inasmuch as it is one of the largest depreciable groups and represents 16 percent of the original cost of depreciable gas plant as of November 30, 2026. The retirement rate method was used to analyze the survivor characteristics of this group. The life table for the 1939-2022 experience band is presented on pages VI-167 through VI-170 of Exhibit No. 5B. The life table, or original survivor curve, is plotted along with the estimated smooth survivor curve, the 55-R2, on page VI-166. The calculations of the annual depreciation related to the original cost as of November 30,2025, of gas plant are presented on pages II-89 through II-91 of Exhibit No. 5A. The calculation is based on the 55-R2 survivor curve, the attained age, and the allocated book reserve. The calculations as of November 30, 2026, are presented on pages VII-91 through VII-93 of Exhibit No. 5B and are based in part on the bringforward of the book reserve. Also, the calculations as of December 31, 2027 are presented on pages II-92 and II-94 of Exhibit No. 5C and are based in part on the bringforward of the book reserve. The tabulations in Exhibit Nos. 5A, 5B, and 5C set forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. The totals are brought forward to Table 1 on page I-4 in Exhibit No. 5A, page V-5 in Exhibit No. 5B, and on page I-4 in Exhibit No. 5C.

Q. IN WHAT MANNER IS NET SALVAGE INCORPORATED IN THE DEPRECIATION CALCULATIONS?

A. As stated on page IV-9 of Exhibit No. 5B no adjustment for net salvage was made to the calculated annual depreciation amounts. The total calculated annual depreciation set forth

on page I-5 of Exhibit No. 5A, page V-6 of Exhibit No. 5B, and on page I-5 of Exhibit No. 5C should include an addition for the amortization of negative net salvage in accordance with the practice of this Commission. The amortization is based on experience during the period 2021 through 2025 for the calculation as of November 30, 2025, and on experience during the period 2022 through 2026 for the calculation as of November 30, 2026. The amortization for the December 31, 2027 calculation is based on experience during the period 2023 through 2027. The amounts of the five-year amortizations are calculated in Table 2 on page I-6 of Exhibit No. 5A, in Table 4 on page V-11 of Exhibit No. 5B, and in Table 4 on page I-10 of Exhibit No. 5C.

Q. DOES THIS COMPLETE YOUR TESTIMONY AT THIS TIME?

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

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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-El-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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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	Integrys – 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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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.	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.	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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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.	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	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.	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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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	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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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 Com	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 Com	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 Com	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	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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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	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

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
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	OR PUC	UM 2363	Northwest Natural Gas Company	Depreciation
484.	2024	IURC	Cause No. 46120	Northern Indiana Public Service Company LLC	Depreciation
485.	2024	MO PSC	GR-2024-0369	Ameren Missouri	Depreciation
486.	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
487.	2024	KY PSC	Case No. 2024-00354	Duke Energy Kentucky	Depreciation
488.	2024	MO PSC	GR-2025-0107	Spire Missouri, Inc.	Depreciation
489.	2024	OR PUC	UG 520	Northwest Natural Gas	Depreciation
490.	2024	TX PUC	SOAH Docket No. 473-25-11219; PUC Docket No. 57568	El Paso Electric	Depreciation
491.	2024	FERC	Docket No. RP24-1106-002	Adelphia Gateway, LLC	Depreciation
492.	2025	PA PUC	Docket No.R-2025-3053499	Columbia Gas of Pennsylvania, Inc.	Depreciation
493.	2025	NE PSC	Case No. NG-124	Black Hills Nebraska	Depreciation
494.	2025	KY PSC	Case No. 2025-00114	Louisville Gas and Electric	Depreciation
495.	2025	KY PSC	Case No. 2025-00113	Kentucky Utilities	Depreciation
496.	2025	PA PUC	Docket No. R-2025-2025-3053442, R-2025-3053573	The York Water Company	Depreciation
497.	2025	NC UC	Docket No. W-218, Sub 629	Aqua North Carolina, Inc.	Depreciation
498.	2025	TX PUC	Docket No. 58124	Aqua Texas, Inc.	Depreciation
499.	2025	FERC	Docket No. ER25-2479-000	Duke Energy Indiana, LLC	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
500.	2025	IURC	Cause No. 46258	Indianapolis Power & Light Company d/b/a AES Indiana	Depreciation
501.	2025	NY PSC	Case 25-E-0375 & Case 25-G-378	New York State Electric and Gas Corporation	Depreciation
502.	2025	NY PSC	Case 25-E-0379 & Case 25-G-0380	Rochester Gas and Electric Corporation	Depreciation
503.	2025	ILL CC	Docket No. 25-0055	Northern Illinois Gas Company d/b/a Nicor Gas Company	Depreciation
504.	2025	CA PUC	A.25-01-001	San Gabriel Water Company	Depreciation
505.	2025	FERC	Docket EL25-77-000	Valley Link	Depreciation
506.	2025	KY PSC	Docket No. 2025-00125	Duke Energy Kentucky	Depreciation
507.	2025	KY PSC	Docket No 2025-00208	East Kentucky Power Cooperative	Depreciation
508.	2025	SC PSC	Docket No. 2025-243-WS	Kiawah Island Utility	Depreciation
509.	2025	MA DPU	D.P.U. 25-170	The Berkshire Gas Company	Depreciation
510.	2025	WA UTC	Docket No. UG-250610	Northwest Natural Gas Company	Depreciation
511.	2025	SC PSC	Docket No. 2025-243-WS	Kiawah Island Utility, Inc. (South Carolina Water)	Depreciation
512.	2025	PA PUC	Docket No. R-2025-3057983, Docket No. R-2025-3058051	Pennsylvania-American Water Company	Depreciation
513.	2025	RI PUC	Docket No. 25-45-GE	Rhode Island Energy	Depreciation
514.	2025	IN URC	Cause No. 46334	Aqua Indiana, Inc.	Depreciation
515.	2025	SC PSC	Docket No. 2025-325-E	Dominion Energy South Carolina, Inc.	Depreciation
516.	2025	CA PUC	A.26-01-001	Suburban Water Systems	Depreciation
517.	2025	VA SCC	Case No. PUR-2025-00071	Aqua Virginia, Inc.	Depreciation
518.	2025	FERC	Docket No. ER26-750-000	Black Hills Power, Inc.	Depreciation
519.	2025	NC UTC	Docket No. E-7, Sub 1329	Duke Energy Carolinas, LLC	Depreciation
520.	2025	NC UTC	Docket No. E-2, Sub 1380	Duke Energy Progress, LLC	Depreciation
521.	2025	KY PSC	Case No. 2025-00257	Kentucky Power Company	Depreciation
522.	2025	PA PUC	Docket No. R-2025-3057237	City of Lancaster	Depreciation
523.	2025	PA PUC	Docket No. R-2025-3057164	PPL Electric Utilities	Depreciation
524.	2025	PA PUC	Docket No. R-2025-3059428	National Fuel Gas Distribution Corporation	Depreciation
525.	2026	PUCO	Case No. 25-1097-GA-AIR, Case No. 25-1098-GA-ALT, Case No. 25-1099-GA-AAM, Case No. 25-1100-GA-ATA	Enbridge Gas Ohio	Depreciation
526.	2026	OR PUC	UM 2428	Portland General Electric	Depreciation
527.	2026	MO PSC	Case No. ER-2026-0143	Evergy Missouri Metro	Depreciation

LIST OF CASES IN WHICH JOHN J. SPANOS SUBMITTED TESTIMONY, cont.

	Year	Jurisdiction	Docket No.	Client Utility	Subject
528.	2025	SD PUC	Docket No. EL26-	Black Hills Power	Depreciation
529.	2025	NM PRC	Case No. 25-XXXX	El Paso Electric Company	Depreciation
530.	2026	ILL CC	Docket No. 26-0065	North Shore Gas Company	Depreciation
531.	2026	ILL CC	Docket No. 26-0066	The Peoples Gas Light and Coke Company	Depreciation

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2026-3060855
PEOPLES NATURAL GAS COMPANY LLC	:	

PREPARED DIRECT TESTIMONY OF
JOHN D. TAYLOR
CHIEF EXECUTIVE OFFICER – ATRIUM ECONOMICS LLC
ON BEHALF OF
PEOPLES NATURAL GAS COMPANY LLC

DATE SERVED: March 27, 2026 Peoples Statement No. 17

DATE ADMITTED: _____

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PREPARED DIRECT TESTIMONY
OF JOHN D. TAYLOR

I. WITNESS IDENTIFICATION AND BACKGROUND

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 Chief Executive Officer. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING THIS DIRECT TESTIMONY?

A. I am submitting testimony on behalf of Peoples Natural Gas Company LLC ("Peoples" or the "Company").

Q. PLEASE DESCRIBE YOUR PROFESSIONAL BACKGROUND AND EMPLOYMENT EXPERIENCE.

A. Peoples Exhibit JDT-1 contains background information summarizing my education, presentation of expert testimony, and other industry-related activities.

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

A. My testimony provides the analytical foundation for Peoples' proposed rates and revenue recovery mechanisms. As such, my testimony addresses four integrated topics. First, I will present the Company's determination of normal weather and test year billing determinants. Second, I prepared and am sponsoring Peoples' fully allocated cost of service study ("ACOSS"), which is found in **Peoples Exhibit No. 11**. The ACOSS determines the embedded costs of serving Peoples' distribution customers associated with the Pennsylvania Public Utility Commission's ("Commission") jurisdiction. Third, I

support the apportionment, or allocation, of the class revenue increase, and the Company's rate design proposal. Finally, I am supporting the Company's Weather Normalization Adjustment ("WNA") mechanism update.

Q. PLEASE SUMMARIZE THE CONTENT OF YOUR TESTIMONY.

My testimony consists of this introduction section (I) and the following nine additional sections: (II) Normal Heating Degree Day Methodology, (III) Peoples' Billing Determinants, (IV) Allocated Cost of Service Study Overview, (V) Peoples' Allocated Cost of Service Study, (VI) Principals of Sound Rate Design, (VII) Peoples' Revenue Apportionment, (VIII) Peoples' Rate Design, (IX) Weather Normalization Adjustment Mechanism, and (X) Summary and Conclusions.

Q. MR. TAYLOR, ARE YOU SPONSORING ANY EXHIBITS IN THIS PROCEEDING?

A. Yes. I am sponsoring the following exhibits :

- Peoples Natural Gas Exhibit No. JDT-1, Resume of John D. Taylor;
- Peoples Natural Gas Exhibit No. JDT-2, Derivation of Total Gathering Cost of Service;
- Peoples Natural Gas Exhibit No. JDT-3, Proposed Class Revenue Apportionment;
- Peoples Natural Gas Exhibit No. JDT-4, Rate Design;
- Peoples Natural Gas Exhibit No. JDT-5, Bill Comparisons;
- Peoples Natural Gas Exhibit No. JDT-6, WNA Mechanism Policy Factors; and
- Peoples Natural Gas Exhibit No. No. 11, Allocated Cost of Service Study.

II. NORMAL HEATING DEGREE DAY METHODOLOGY

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR DIRECT TESTIMONY.

A. In this section of my testimony, I first present the Company's chosen methodology for determining normal weather, specifically for determining normal Heating Degree Days ("HDD"). Normal HDD is used to estimate the level of gas usage if HDD had been at a normal level, whether for a historic period or a future period.

Q. WHAT METHODOLOGY IS USED TO DETERMINE NORMAL HDD?

A. Peoples has chosen to use a trend methodology to estimate normal HDD. Recognizing that there is a clear, and generally accepted, climate warming trend (a downward trend in annual HDD), Peoples has chosen to use a regression-based methodology to estimate that warming trend and to develop an estimate of normal HDD. The trend is first estimated using sixty-five years of annual HDD data, and then that trend is extrapolated to calculate normal HDD in the Fully Projected Future Test Year ("FPFTY") of calendar year 2027.

The regression uses sixty-five years of annual Pittsburgh Area[1] HDD data (from 1960 to 2024) for the regression dependent variable, with a constant and trend as explanatory (or independent) variables. This is the standard method to estimate a linear trend in data. The regression equation is:

$$Annual\ HDD_y = \mathbf{Constant} + \boldsymbol{\beta} \times Trend_y$$

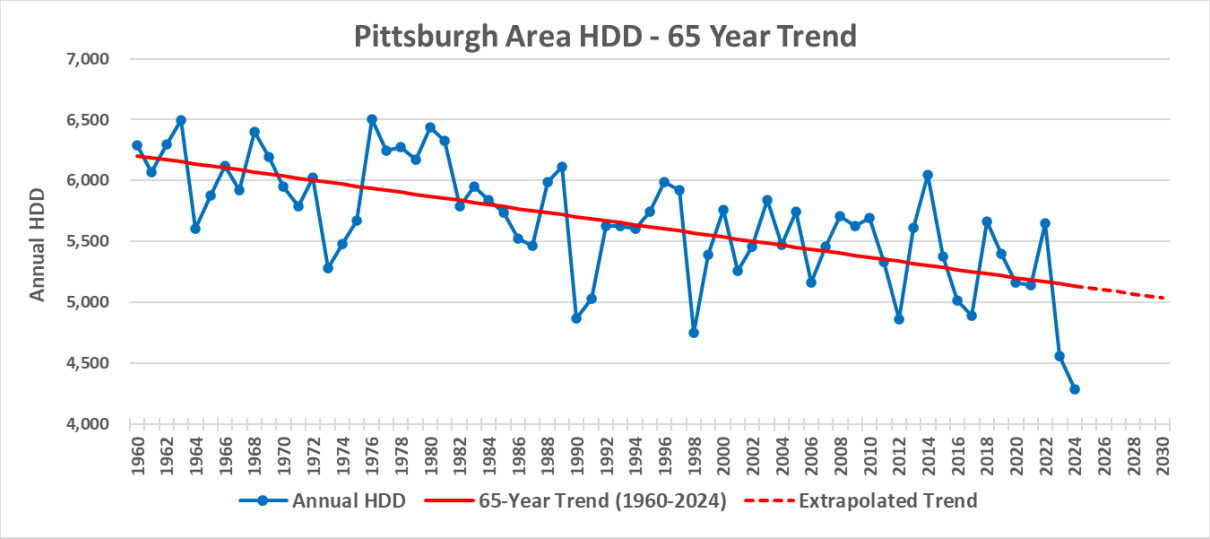
Where:

[1] HDD data is from the National Weather Service / NOAA for the "Pittsburgh Area". https://www.weather.gov/wrh/Climate?wfo=pbz

- *Annual HDD$_y$* is annual Pittsburgh Area HDD with a 65-degree base for year 'y' from 1960 to 2024, e.g., HDD$_{1970}$ is the annual HDD in 1970.
- *Trend$_y$* is the trend annual series, 1, 2, 3, 4, …, 65, from 1960 to 2024. The trend series could equivalently be the years 1960, 1961, 1962, …, 2024 and would produce an identical HDD trend, but with different coefficient estimates.
- **Constant** is the regression constant coefficient (or "intercept"), estimated to be 6,221 in this case.
- **β** is the coefficient of the trend variable, estimated to be -16.69 in this case, meaning that each year, it is estimated that annual HDD will be lower by 16.69 degrees.

The resulting trend is graphically depicted in Figure 1:

Figure 1 - Pittsburgh Area HDD - 65 Year Trend



Q. WHAT IS THE ESTIMATE OF NORMAL HDD FOR THE FPFTY USING THE TREND METHODOLOGY?

A. Extrapolating the regression trend (dotted red line in Figure 1) results in an annual HDD estimate for 2027, the FPFTY, of 5,086. The estimated normal HDD for 2026 is 5,103 and for 2028 is 5,069, reflecting the negative trend in annual HDD.

Q. CAN MONTHLY NORMAL HDDS BE DERIVED FROM THE ANNUAL TREND REGRESSION, AND IF SO, HOW?

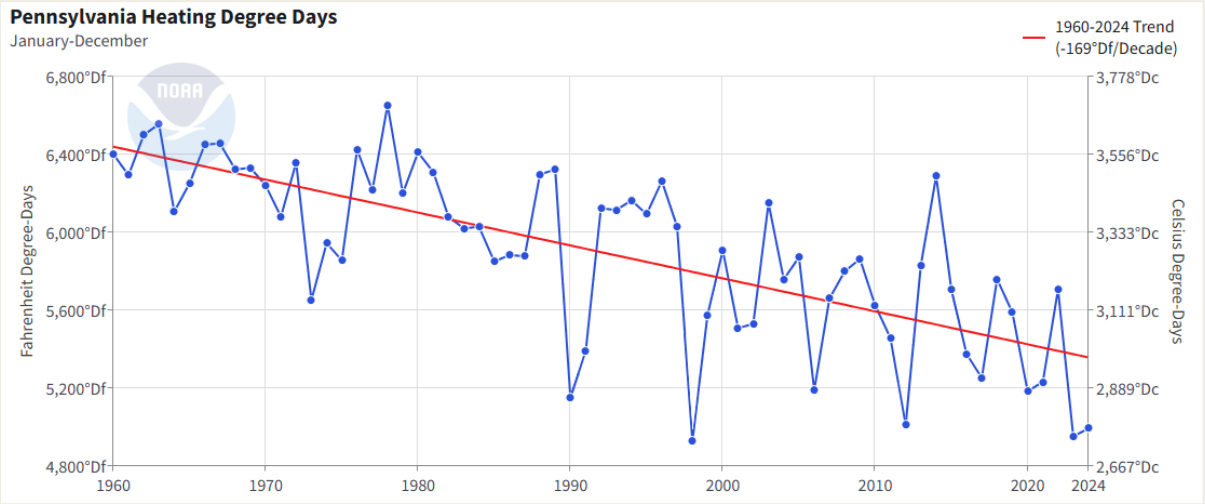
A. Yes. Monthly normal HDD is derived from annual normal HDD based on the average monthly HDD as a percentage of annual HDD over the 65-year period from 1960 to 2024. For example, over the past 65 years, actual HDD in January has on average been 20.21-percent (20.21%) of total annual HDD, so January normal HDD for 2027 is 20.21% of 5,086, or 1,028 HDD.

Q. ARE THESE RESULTS CONSISTENT WITH OTHER INDEPENDENT ANALYSIS?

A. Yes. The National Oceanic and Atmospheric Administration ("NOAA") provides the ability to do similar HDD analysis by State and Region through their internet site[2]. Figure 2 below shows annual HDD and trend for the Commonwealth of Pennsylvania for the same historical date range; 1960 through 2024.

[2] https://www.ncei.noaa.gov/access/monitoring/climate-at-a-glance/statewide/time-series

Figure 2 - NOAA Annual Pennsylvania HDD



The trend (-169 degrees per decade) in Figure 2 is very similar to the trend coefficient in the Pittsburgh Area HDD regression (-16.69 degrees per year).

Q. IN THE PREVIOUS RATE CASE (R-2023-3044549) AN AVERAGE OF THE 65-YEAR TREND AND A 20-YEAR AVERAGE WAS USED TO ESTIMATE NORMAL HDD. WHY HAS THIS CHANGED?

A. In the prior proceeding, the blended methodology reflected a gradual transition toward greater reliance on regression-based normalization. Averaging the 65-year regression trend with a 20-year historical average balanced long-term trend recognition with a more recent historical reference point, consistent with the principle of gradualism.

Since that case, additional data have further confirmed the persistence and consistency of a long-term warming trend. The 65-year regression framework captures that trend in a statistically rigorous manner by incorporating the full historical dataset and identifying the central tendency over time, rather than relying on a fixed historical averaging window.

While a 20-year average reflects relatively recent conditions, it does not account for the directional trend observed across the broader historical record. As a result, it embeds legacy weather patterns that are not representative of forward-looking expectations. The regression methodology, by contrast, reflects both the long-term record and the directional evolution of HDD.

Given the continued confirmation of the trend and the Company's use of the 65-year regression to normalize billing determinants in this proceeding, reliance solely on the regression methodology is appropriate. Continuation of the blended approach does not reflect the most reasonable estimate of HDD for the FPFTY in this case. The regression framework alone provides a transparent and analytically sound estimate of normal HDD.

III. PEOPLES' BILLING DETERMINANTS

Q. PLEASE SUMMARIZE THIS SECTION OF YOUR DIRECT TESTIMONY.

A. In this section of my testimony, I present the customer count forecast and normal usage estimate for the FPFTY. The same methodology used to develop the FPFTY normal usage estimate is used to normalize usage for the Historic Test Year ("HTY"), or in other words, estimate what usage would have been in the HTY had HDD been at normal levels.

Q. FOR WHAT RATE CLASSES HAVE YOU DEVELOPED CUSTOMER COUNT FORECASTS AND NORMAL USAGE ESTIMATES?

A. I have developed customer count forecasts and normal usage estimates for Residential, Small General Service ("SGS"), and Medium General Service ("MGS") rate classes using a regression methodology. The usage for these rate classes is generally considered to be weather sensitive and therefore should be weather normalized.

For Large Commercial and Industrial rate classes, actual numbers of customers and usage from the HTY is used to project future customer numbers and usage. The Company performs this calculation drawing upon its expertise and insights regarding these large customers to provide a reliable projection of future usage.

Q. PLEASE DESCRIBE THE PROCESS USED TO DEVELOP THE FPFTY NORMALIZED USAGE ESTIMATE FOR RESIDENTIAL, SGS, AND MGS RATE CLASSES.

A. The process consists of two primary components:

1) Forecasting the number of customers by rate class, and

2) Estimating normal Usage Per Customer ("UPC") by rate class.

The normalized usage estimate results from the multiplication of the customer count forecast by the normalized UPC estimate (i.e., an estimate of UPC at normal HDD) at the FPFTY.

Q. WHAT IS THE SOURCE OF THE CUSTOMER, UPC, AND HDD DATA?

A. Peoples provided historical monthly customer counts for Residential and Commercial, retail and transport, from January 2015 to May 2025. UPC is developed from individual customer billing data provided by Peoples, aggregated by rate category and billing month. Data is from January 2017 through May 2025. HDD data is from the National Weather Service / NOAA for the "Pittsburgh Area".

Q. HOW IS THE NUMBER OF CUSTOMERS FORECAST?

A. The number of customers is forecasted with a two-step process. First, the number of monthly Retail and Transport within Residential and Commercial is estimated, then

forecasted, using a regression methodology. Second, the Retail and Transport forecasts are broken down into sub-classes. The Residential Retail forecast is broken into Retail (non-CAP) and Retail CAP using the Company's assumption about the future number of CAP customers. The Commercial Retail and Transport forecasts are broken into SGS and MGS (each with two usage tier subclasses) based on the actual number of customers in May 2025.

Q. PLEASE FURTHER EXPLAIN THE REGRESSION METHODOLOGY FOR THE CUSTOMER FORECAST.

A. Regression models are used to estimate a relationship between the number of customers, which is the "dependent" variable in the regression, and "independent" or "explanatory" variables, which consist of a Constant, a Trend, and monthly indicator variables (often informally called "dummy" variables). The monthly indicator variables model the cyclical pattern often seen in monthly customer numbers. Although evaluated individually for each customer class, the customer regression models are generally of the form:

$$Customers_m = \textbf{Constant} + \boldsymbol{\beta_1} \times Trend_m + \boldsymbol{\beta_2} \times M_2 + \boldsymbol{\beta_3} \times M_3 + \ldots + \boldsymbol{\beta_{12}} \times M_{12}$$

Where:

- $Customers_m$ is monthly number of customers for the month 'm' from January 2023 to May 2025.
- $Trend_m$ is the monthly trend series 1, 2, 3, ...
- M_2 through M_{12} are monthly indicator variables for February through December, which take the value 1 for the month and 0 otherwise. The indicator variable for January is excluded.

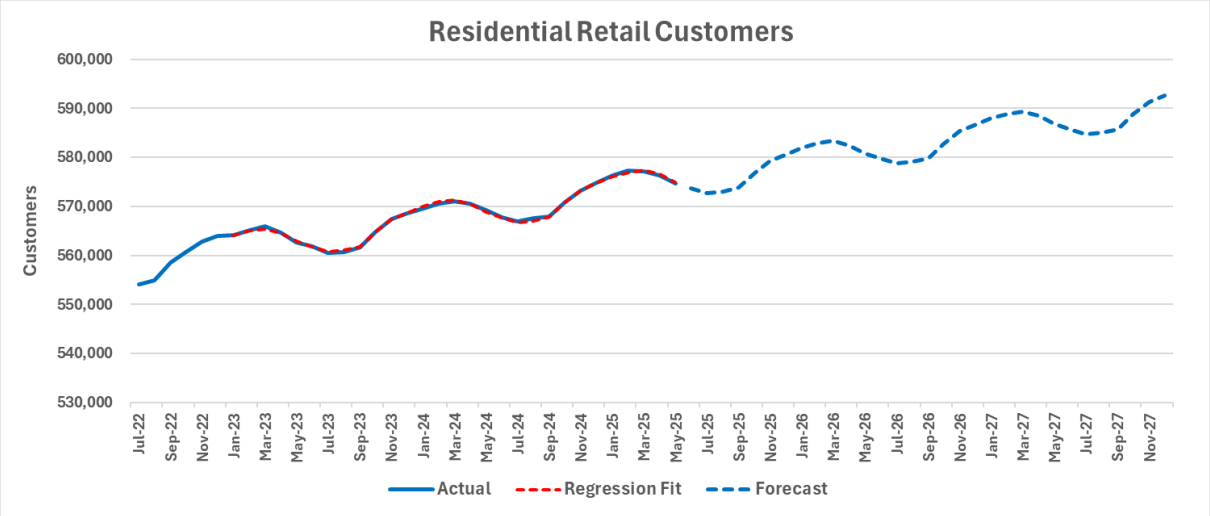
- **Constant** is the estimated constant coefficient in the regression.
- β_1 through β_{12} are the estimated regression coefficients.

The estimates of the Constant, Trend coefficient and monthly indicator variable coefficients are used to forecast the number of customers through 2027. The forecast is primarily driven by the Trend variable. For example, if the Trend variable for the last month of actual data, May-2025, has a value of 100, the customer forecast for June-2025 would use the Trend variable with a value of 101.

Q. PLEASE GIVE AN EXAMPLE OF THE CUSTOMER FORECAST ANALYSIS.

A. Figure 3 illustrates this analysis for Residential Retail customers.

Figure 3 - Residential Retail Customers - Actual & Forecast



Recent historical Residential customer numbers are first used to estimate a regression model, and then the estimates of the Constant, Trend coefficient, and monthly coefficient estimates are used to forecast the customer numbers through 2027. A similar regression analysis is performed for Residential Transport customers, and Commercial Retail and Transport customers.

Q. HOW IS THE ESTIMATE OF NORMAL UPC DEVELOPED?

A. First, regression models are used to estimate the relationship between UPC and HDD. Then the models are evaluated at an estimate of normal HDD to develop an estimate of normal UPC, or what UPC would be if HDD was at normal levels.

Q. PLEASE PROVIDE A DETAILED EXPLANATION OF THE UPC REGRESSION MODELS.

A. Regression models are specified to estimate the relationship between UPC and a Constant, HDD, and monthly indicator variables. In the regression, UPC is the "dependent" variable, and the Constant, HDD terms and monthly indicator variables are the "independent" or "explanatory" variables. Although evaluated individually for each rate class, the UPC regression models are generally of the form:

$$UPC_m = \textbf{Constant} + \boldsymbol{\beta_1} \times HDD_m + \boldsymbol{\beta_2} \times HDD_{m-1} + \boldsymbol{\beta_3} \times M_1 + \ldots + \boldsymbol{\beta_{13}} \times M_{12}$$

Where:

- UPC_m is monthly UPC for the month 'm' from August 2018 to May 2025.
- HDD_m and HDD_{m-1} are HDD for month 'm' and the prior month. Current and prior month HDD are used because UPC is based on usage billed in a month, which is comprised of actual usage during the current (billed) month and prior month.
- M_1 through M_{12} are monthly indicator variables for January through December and take the value 1 for the month and 0 otherwise. A monthly indicator variable, usually August, is excluded.
- **Constant** is the estimated constant coefficient in the regression.

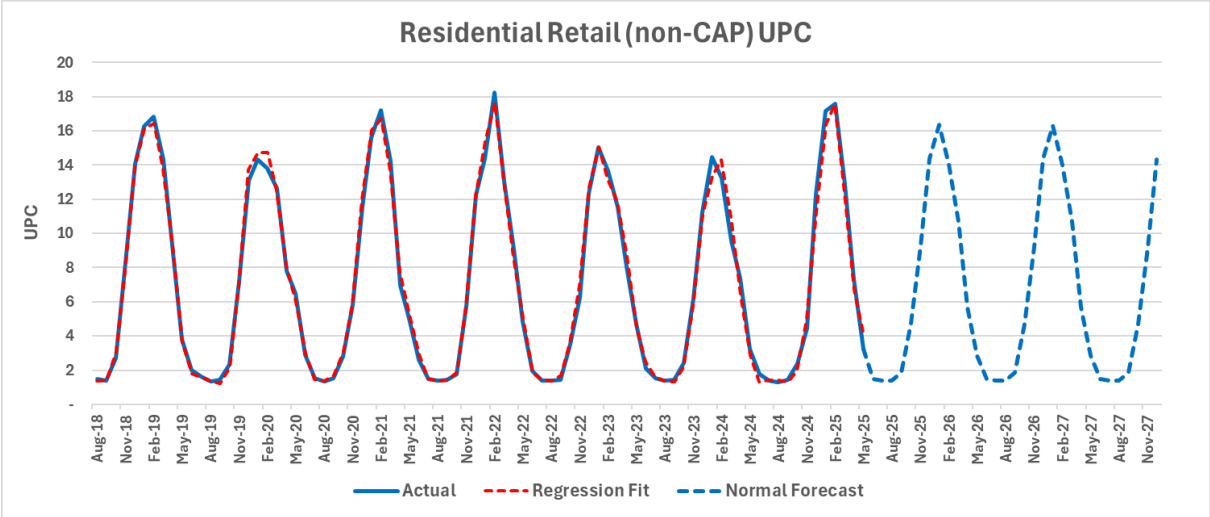
- β_1 through β_{13} are the estimated regression coefficients.

Second, the estimated regression coefficients, for each rate class, along with the monthly normal HDD develop with the HDD trend regression, are used to estimate (or "forecast") the normal monthly UPC; or in other words, estimate what UPC would be if HDD were the normal HDD developed with the HDD trend regression.

Q. PLEASE GIVE AN EXAMPLE OF THE UPC REGRESSION ANALYSIS AND FORECAST.

A. Figure 4 represents this analysis for Residential Retail (non-CAP) UPC.

Figure 4 - Residential Retail (non-CAP) UPC - Actual & Forecast



Historical Residential Retail (non-CAP) UPC is used to estimate the regression model. The Constant, HDD and monthly parameter estimates, along with the estimate of normal HDD, are used to forecast the UPC for the FPFTY (2027). Similarly for Residential CAP and Transport and Commercial rate classes.

Q. PLEASE SHOW AN EXAMPLE OF HOW THE FORECAST COMPONENTS COME TOGETHER TO PRODUCE AN ESTIMATE OF NORMAL USAGE FOR THE FPFTY (2027).

A. Figure 5 shows actual historical and estimated normal Total Residential usage, and Table 1 shows the three components of Total Residential usage; each component having a forecast of the number of customers, an estimate of normal UPC and the resulting usage for the FPFTY (2027).

Figure 5 - Residential Total Usage - Actual & Normal Estimate

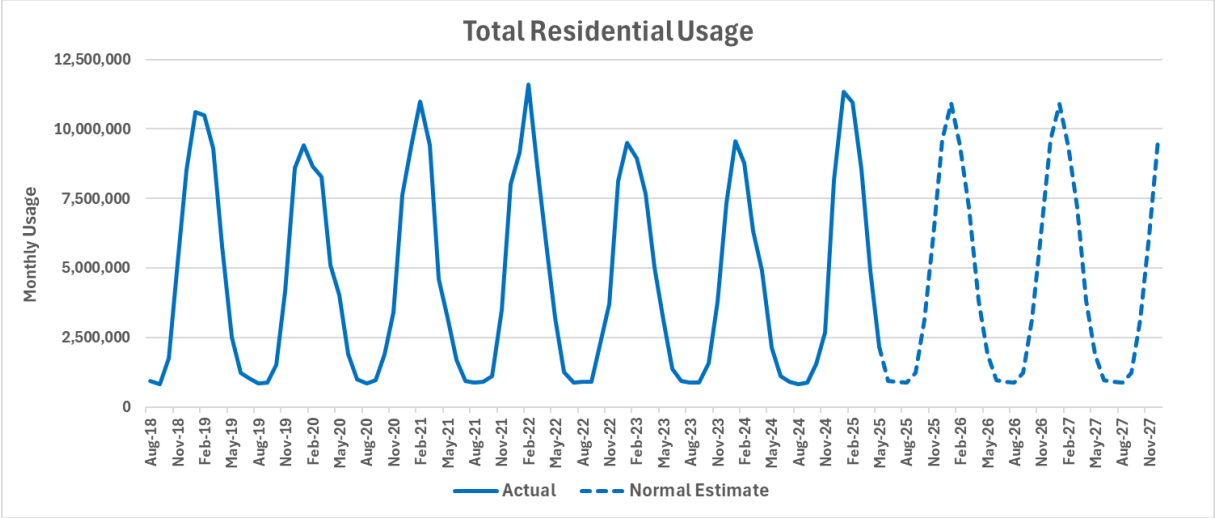


Table 1 - Residential Customer Forecast & Estimated Normal Usage

	Residential Retail (non CAP)			Residential CAP			Residential Transport		
Month	Customers	UPC	Usage	Customers	UPC	Usage	Customers	UPC	Usage
Jan-27	548,954	16.30	8,947,244	39,010	21.44	836,347	66,487	16.96	1,127,777
Feb-27	549,892	13.99	7,691,359	39,010	18.43	718,905	66,126	14.55	962,010
Mar-27	550,293	10.68	5,876,275	39,010	14.35	559,946	65,766	11.19	736,156
Apr-27	549,454	5.68	3,122,586	39,010	7.88	307,535	65,405	6.04	394,829
May-27	547,811	2.85	1,560,004	39,010	3.84	149,626	65,044	3.04	197,534
Jun-27	546,677	1.46	798,982	39,010	1.72	66,924	64,684	1.53	98,842
Jul-27	545,714	1.40	762,892	39,010	1.54	60,215	64,323	1.44	92,533
Aug-27	546,040	1.38	752,812	39,010	1.55	60,567	63,962	1.41	90,284
Sep-27	546,730	1.87	1,024,407	39,010	2.58	100,786	63,602	1.95	124,250
Oct-27	549,745	4.69	2,579,961	39,010	6.75	263,285	63,241	4.97	314,592
Nov-27	552,276	9.20	5,082,200	39,010	12.63	492,860	62,880	9.71	610,559
Dec-27	553,625	14.32	7,925,185	39,010	19.08	744,222	62,520	14.98	936,614
Total	**6,587,212**	**83.82**	**46,123,907**	**468,120**	**111.80**	**4,361,218**	**774,040**	**87.77**	**5,685,980**

Q. HOW ARE THE UPC REGRESSION RESULTS USED TO WEATHER-NORMALIZE HTY USAGE?

A. The estimated coefficient, β_1, for the HDD term in the UPC regression equation represents an estimate of the weather sensitivity of UPC to HDD, specifically, β_1 is the estimate of monthly Mcf per customer per HDD degree. The difference between normal HDD and actual HDD for a particular month, multiplied by β_1, provides an estimate of the difference in actual UPC from UPC had HDD been normal, or "normal UPC". Multiplying by the number of customers gives the estimate of the difference in actual usage from "normal usage", or usage had HDD been normal. The equation for the Normal Weather Usage Adjustment ("NWUA") for month 'm' is:

$$NWUA_m = (\text{Normal } HDD_m - \text{Actual } HDD_m) \times \beta_1 \times (\text{Actual Customers}_m)$$

Applying this equation to the months of the HTY, by rate class, and summing to annual, is the HTY Normal Weather Usage Adjustment.

For a hypothetical example, if for January, Actual HDD is 1,000 and Normal HDD is 1,100, and β_1 is 0.014, and there were 500,000 customers, the Weather Normalization Adjustment would be 700,000 Mcf. From the above equation for NWUA:

$$700{,}000 = (1{,}100 - 1{,}000) \times 0.014 \times 500{,}000$$

Due to January being 100 HDD warmer than normal, 700,000 Mcf is added to actual usage in January to produce weather normalized usage. In other words, it is estimated that 700,000 more Mcf would have been used in January had HDD been normal.

IV. ALLOCATED COST OF SERVICE STUDY OVERVIEW

Q. WHAT IS THE GENERAL PURPOSE AND USE OF AN ACOSS IN REGULATORY PROCEEDINGS?

A. The purpose of an ACOSS is to allocate the gas distribution utility's overall FPFTY costs to the various classes of service in a manner that reflects the relative costs of providing service to each class. An ACOSS represents an analysis of which customer or group of customers cause the utility to incur the costs to provide service. The requirement to develop the ACOSS results from the nature of utility costs. Utility costs are characterized by the existence of common costs. Common costs occur when the fixed costs of providing service to one or more rate classes, or the cost of providing multiple products to the same rate class, use the same facilities and the use by one rate class precludes the use by another rate class.

In addition, utility costs may be fixed or variable in nature. Fixed costs do not change with the level of gas throughput, while variable costs change directly with changes in gas throughput. Most non-fuel related utility costs are fixed in the short run and do not vary with changes in customers' loads. This includes the cost of distribution mains, service lines, meters, and regulators.

Finally, the ACOSS provides different contributions to the development of economically efficient rates and the cost responsibility by rate class. This is accomplished through analyzing costs and assigning each rate class its proportionate share of the utility's total revenues and costs within the test year. The results of these studies can be utilized to determine the relative cost of service for each rate class to help determine the individual class revenue responsibility and provide guidance with rate design. Using the cost information per unit of demand, customer, and commodity developed in the ACOSS to

understand and quantify the allocated costs in each rate class is a useful step in the rate design process to guide the development of rates.

Q. IS THE PREPARATION OF AN ACOSS AN EXACT SCIENCE?

A. No. The fundamental purpose of an ACOSS is to aid in the design of rates to be charged by identifying all of the capital and operating costs incurred by a utility to provide service to all of its customers and then assigning or allocating those costs to individual rate classes based on how those rate classes cause the costs to be incurred. The allocation of costs using an ACOSS is a practical requirement of utility regulation since rates are based on the cost of service for the utility under a cost-based regulatory model. As a general matter, utilities must be allowed a reasonable opportunity to earn a return of and on the assets used to serve their customers, with such return on being reflective of a fair rate of return. This is the cost of service standard and equates to the revenue requirements for utility service. The opportunity for the utility to earn its allowed rate of return depends on the rates applied to customers producing revenues that equate to the level of the revenue requirement.

Q. IS THERE A GUIDING PRINCIPLE THAT SUPPORTS THE APPROPRIATE ALLOCATION OF COSTS?

A. Yes, a fundamental foundational principle, cost causation, should be followed to produce accurate and reasonable results. Cost causation addresses the need to identify which customer or group of customers causes the utility to incur particular types of costs, so the analysis results in an appropriate allocation of the utility's total revenue requirement among the various rate classes. In other words, the costs assigned or allocated to particular

customers should be those costs that the particular customers caused the utility to incur because of the characteristics of the customers' usage of utility service.

Q. HOW DO YOU ESTABLISH THE COST AND UTILITY SERVICE RELATIONSHIPS?

A. An important element in the selection and development of a reasonable ACOSS methodology is the establishment of relationships between customer requirements, load profiles, and usage characteristics on the one hand and the costs incurred by the company in serving those requirements on the other hand. To accomplish this, I reviewed Peoples' expense and plant accounts, operational data, usage information, and conducted interviews with Peoples' employees. The details and data gathered provided information on the key factors that cause the costs to vary and supported studies of the relative costs of providing facilities and services for each rate class. From the results of those analyses, methods of direct assignment and common cost allocation methodologies can be chosen for the utility's plant and expense elements.

Q. WHAT ARE THE STEPS TO PERFORMING AN ACOSS?

A. A three-step analysis of the utility's total operating costs must be undertaken to establish each customer class's cost responsibility. The three steps that are the basis to conduct an ACOSS are: (1) cost functionalization, (2) cost classification, and (3) cost allocation.

Q. PLEASE DESCRIBE COST FUNCTIONALIZATION.

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. Peoples' primary functional cost categories associated with natural gas distribution services include

gas supply, gathering, storage, transmission, distribution, on-site distribution (services, meters, etc.), and customer accounts and services. Indirect costs that support these functions, such as general plant and administrative and general expenses, are allocated to functions using allocation factors related to plant and/or labor ratios, i.e., internal allocation factors.

Q. PLEASE DESCRIBE COST CLASSIFICATION.

A. The second step, cost classification, further separates the functionalized plant and expenses according to the primary factors that determine the amount of costs incurred. These factors are: (1) the number of customers; (2) the need to meet the peak demand requirements that customers place on the gas distribution system; and (3) the amount of gas consumed by customers. These classification categories have been identified for purposes of the ACOSS as: (1) customer costs; (2) demand costs; and (3) commodity costs, respectively.

Q. PLEASE DESCRIBE THE TYPES OF COSTS CONTAINED IN THE CUSTOMER, DEMAND, AND COMMODITY COSTS CATEGORIES.

A. Customer-related costs are incurred to attach a customer to the gas distribution system, meter any gas usage, and maintain the customer's account. Customer costs are a function of the number of customers served by the utility and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators, customer service, and accounting expenses.

Demand or capacity related costs are associated with plant that is designed, installed, and operated to meet maximum hourly or daily gas flow requirements, such as the utility's transmission and distribution mains, or more localized distribution facilities that are designed to satisfy individual customer maximum demands. Gas supply contracts also have a capacity related component of cost relative to Peoples' requirements for serving daily peak demands and the winter peaking season.

Commodity related costs are those costs that vary with the throughput sold to, or transported for, customers. Costs related to gas supply are classified as commodity because they vary with the amount of gas volumes purchased by Peoples for its customers.

Q. PLEASE DESCRIBE THE COST ALLOCATION PROCESS.

A. The final step is to allocate each functionalized and classified cost element to the individual rate class. Costs are typically allocated on customer, demand, commodity, or revenue allocation factors. From a cost-of-service perspective, the best approach is a direct assignment of costs where costs are incurred by a customer or class of customers and can be so identified. Where costs cannot be directly assigned, the development of allocation factors by rate class uses principles of both economics and engineering. This results in appropriate allocation factors for different elements of costs based on cost causation. For example, we know from the way customers are billed that each customer requires a meter. Meters differ in size and type depending on the customer's load characteristics. These meters have different costs based on size and type. Therefore, differences in the cost of meters are reflected by using a different average meter cost for each class of service.

Q. ARE THERE FACTORS THAT CAN INFLUENCE THE OVERALL COST ALLOCATION FRAMEWORK UTILIZED BY A GAS UTILITY WHEN PERFORMING AN ACOSS?

A. Yes. First, the fundamental and underlying philosophy applicable to all cost studies pertains to the concept of cost causation for purposes of allocating costs to customer groups. Cost causation addresses the question – which customer or group of customers causes the utility to incur particular types of costs? To answer this question, it is necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. The factors that can influence the cost allocation used to perform an ACOSS include: (1) the physical configuration of the utility's gas system; (2) the availability of data within the utility; and (3) the state regulatory policies and requirements applicable to the utility.

Q. WHY ARE THESE CONSIDERATIONS RELEVANT TO CONDUCTING PEOPLES' ACOSS?

A. It is important to understand these considerations because they influence the overall context within which a utility's cost study is conducted. In particular, they provide an indication of where efforts should be focused for purposes of conducting a more detailed analysis of the utility's gas system design and operations and understanding the regulatory environment in the state the utility operates in as it pertains to cost of service studies and gas ratemaking issues.

Q. HOW DOES THE AVAILABILITY OF DATA INFLUENCE AN ACOSS?

A. The structure of the utility's books and records can influence the cost study framework. This structure relates to attributes such as the level of detail, segregation of data by operating unit or geographic region, and the types of load data available.

Q. HOW DO STATE REGULATORY POLICIES AFFECT A UTILITY'S ACOSS?

A. State regulatory policies and requirements prescribe whether there are any historical precedents used to establish utility rates in the state. Specifically, state regulations and past precedents set forth the methodological preferences or guidelines for performing cost studies or designing rates which can influence the proposed cost allocation method utilized by the utility.

V. PEOPLES' ALLOCATED COST OF SERVICE STUDY

Q. PLEASE DESCRIBE THE ATRIUM MODEL USED IN CONDUCTING THE ACOSS FILED IN THIS PROCEEDING.

A. Peoples has selected the Atrium excel-based model ("Atrium ACOSS Model") to conduct the ACOSS in this general base rate case. Atrium developed the Atrium ACOSS Model on a proprietary basis for its consulting engagements, and it has been used in multiple jurisdictions. This is the same model I sponsored in the UGI Utilities, Inc. - Gas Division Docket No. R-2024-3052716 and Docket No. R-2025-3059523, and also National Fuel Gas Distribution Docket No. R-2022-3035730 and Docket No. R-2025-3059428.

Q. PLEASE DESCRIBE THE PROCESS OF PERFORMING PEOPLES' ACOSS PRESENTED IN THIS FILING.

A. The detailed process description of Peoples' ACOSS analysis is presented in **Peoples Exhibit No. 11**, providing a full scope of the process including the development of

allocation factors that support various cost of service studies presented in this proceeding as discussed below.

Q. PLEASE DISCUSS THE CONTENT OF EXHIBIT NO. 11.

A. **Peoples Exhibit No. 11** provides the information required under 52 Pa. Code § 53.53(a)(1) and, in particular, Exhibit A - Gas Utilities, by providing a cost of service study that fully distributes the Pennsylvania jurisdictional costs of providing retail distribution service to the various rate classes at both present and proposed rates. See 52 Pa. Code § 53.53(a)(1), Exhibit A.

Peoples Exhibit No. 11 consists of three sections detailing the process of developing the ACOSS. Section I – Introduction includes an introduction, the general purpose and process of the ACOSS, as well as an overview of the excel-based fully functional ACOSS model presented in this proceeding. Section II – Peoples' Cost of Service Procedures presents the ACOSS development process specific to the Company, including the Functionalization, Classification, and Allocation of costs. The Allocation section (Section II.3) describes all internal and external allocation factors and the allocation processes used in the ACOSS. The last section, Section III – Peoples' Cost of Service Results depicts the results of the ACOSS, including revenue requirement apportionment, comparison of cost of service with revenues under current and proposed rates, and development of rate of return by customer class under current and proposed rates.

Q. PLEASE DESCRIBE THE SCHEDULES INCLUDED IN EXHIBIT NO. 11.

A. **Peoples Exhibit No. 11** contains a narrative description of the ACOSS procedures, provides details on the allocation factors, and contains the following Schedules:

- Schedule 1 – Summary of Cost of Service and Rate of Return Under Current and Proposed Rates
- Schedule 2 - Functionalized and Classified Rate Base and Revenue Requirement, and Unit Costs by Customer Class
- Schedule 3 - Cost of Service Allocation Study Detail by Account
- Schedule 4 - Account Balances and Allocation Methods
- Schedule 5 - External Allocation Factors
- Schedule 6 - Internal Allocation Factors

Q. WHAT WAS THE SOURCE OF THE COST DATA ANALYZED IN PEOPLES' ACOSS?

A. All cost-of-service data was extracted from the Company's total cost of service (*i.e.*, total revenue requirement) and schedules contained in this general rate case filing for the FPFTY ending December 31, 2027. Where more detailed information was required to perform various analyses related to certain plant and expense elements, the data was derived from the historical books and records of the Company and information provided by Company personnel.

Q. HOW ARE PEOPLES' RATE CLASSES STRUCTURED FOR THE PURPOSES OF CONDUCTING ITS ACOSS?

A. For Peoples' ACOSS, I included five customer classes:

ACOSS Customer Class	Rate Schedule[3]
Residential	Rate RS, Rate CAP, Rate E-CAP
Small General	Rate SGS
Medium General	Rate MGS
Large General	Rate LGS
Mainline Service	Rate MLS

Q. IS THE COMPANY PROPOSING ANY MODIFICATION TO THE CURRENT CUSTOMER CLASSES?

A. No. The Company is not proposing any modifications to the existing customer classes. The current class structure aligns with the Company's approved tariff schedules and is consistent with the configuration adopted in the Company's most recent general rate case, Docket No. R-2023-3044549.

Q. HOW DID YOU CLASSIFY AND ALLOCATE THE COST OF DISTRIBUTION MAINS?

A. The cost of distribution mains was classified using an Average Study that combines the results of a Customer–Demand study and a Demand–Commodity study. This approach was applied separately to low-pressure and regulated pressure mains.

Under the Customer–Demand study, mains costs are classified between customer and demand components based on the results of a Minimum Size System ("MSS") study. Under the Demand–Commodity study, mains costs are classified on a 50/50 basis between demand and commodity components.

The Average Study reflects an equal weighting of these two approaches. The resulting classification is shown below in Table 2.

[3] Including transportation and standby services

Table 2 –Average Study Classification

	(a) Customer-Demand Study	(b) Demand-Commodity Study	(a) and (b) Average
Customer	48.14%	0.00%	24.07%
Demand	51.86%	50.00%	50.93%
Commodity	0.00%	50.00%	25.00%
Total	100.00%	100.00%	100.00%

The classified costs are then allocated to customer classes using the corresponding allocation factors for each component.

Q. IS THE METHOD USED BY THE COMPANY TO DETERMINE A CUSTOMER COST COMPONENT OF DISTRIBUTION MAINS A GENERALLY ACCEPTED TECHNIQUE FOR DETERMINING CUSTOMER COSTS?

A. Yes. The two most commonly used methods for determining the customer cost component of distribution mains facilities consist of the following: (1) the zero-intercept approach and (2) the most commonly installed, minimum-sized unit of plant investment or MSS.

Two widely recognized references relied upon in the preparation of embedded cost of service studies—Electric Utility Cost Allocation Manual by John J. Doran et al. (National Association of Regulatory Utility Commissioners) and Gas Rate Fundamentals (American Gas Association)—describe minimum system concepts and methods as an appropriate technique for determining the customer component of utility distribution facilities. Accordingly, the inclusion and application of a customer component for distribution facilities, including distribution mains, is a well-supported and commonly accepted practice in the gas industry.

Please refer to Exhibit No. 11 for the detailed MSS study development process and results.

Q. HOW WERE THE COSTS OF THE COMPANY'S GATHERING SYSTEM ALLOCATED IN ITS COST-OF-SERVICE STUDY.

A. Peoples' gathering system is used to transport gas supplies delivered to its gas distribution system for its system supply and its end-use customers from local production facilities located within its service area. The plant and associated expenses for Peoples' gathering system were allocated to its classes of service based on the percentage of annual gas volumes in each class supplied by Pennsylvania gas producers that moved through the Company's gathering system. It is important to note that only a portion of the costs of People's gathering system allocated to each class of service was ultimately reflected in those classes' overall cost to serve. This is because a portion of gathering costs is recovered directly from the local gas producers connected to Peoples' system, with these associated producer revenues credited to the same rate classes receiving the cost allocation. In addition, the total Gathering cost of service is summarized in **Peoples Natural Gas Exhibit No. JDT-2**.

Q. HOW WERE THE COSTS OF THE COMPANY'S UNDERGROUND STORAGE FACILITIES ALLOCATED IN ITS COST-OF-SERVICE STUDIES?

A. Peoples currently owns and operates the Dice Storage Field, which has 1,530,000 Mcf of storage capacity and 32,000 Mcf of maximum design day withdrawal capacity. Peoples' underground storage is used to generally support the unplanned daily balancing requirements of its sales and transportation service customers. Based on a five-year

historical review of the daily withdrawal activity of this facility, it was determined that gas volumes are primarily withdrawn from this storage facility on most days during the months of December through May. As a result, Peoples' Storage Lines and Storage M&R Equipment were allocated to the rate classes in proportion to the total gas sales and transportation volumes for each class during the six-month period of December through May.

Q. DOES PEOPLES' ACOSS INCLUDE GAS COMMODITY COSTS?

A. Yes. The gas costs reflected in the ACOSS correspond to gas cost revenues that have a neutral impact on the study's results, resulting in a net-zero effect.

Q. PLEASE SUMMARIZE THE RESULTS OF THE COMPANY'S ACOSS.

A. Table 3 below presents a summary of the Company's ACOSS that can be reviewed in **Peoples Exhibit No. 11**. The ACOSS shows an overall revenue requirement of $1,347.8 million and a resulting deficiency of $163.2 million. The Company is proposing changes to forfeited discount revenue, gathering revenue and miscellaneous services charges equal to $2.3 million, resulting in a base rate deficiency of $160.9 million as shown in Table 3. The revenue deficiency/excess for each rate class shows revenue increases or decreases necessary to get the classes to their cost to serve.

Table 3 - Summary Results of the Company's ACOSS[4]

Customer Classes	Current Revenues	Cost to Serve	Class Revenue (Deficiency)/ Excess	Percentage Change to Cost to Serve
Residential	$ 875,171,173	$ 1,000,138,402	$ (124,967,230)	14.28%
Small General	116,045,549	146,336,484	(30,290,935)	26.10%
Medium General	108,167,260	130,673,890	(22,506,630)	20.81%
Large General	72,051,809	52,346,079	19,705,730	-27.35%
Mainline Service	13,178,274	18,291,147	(5,112,874)	38.80%
Total System	**$ 1,184,614,065**	**$ 1,347,786,003**	**$ (163,171,938)**	**13.77%**
Increase to Other Revenues			2,300,922	
Total	**1,184,614,065**	**1,347,786,003**	**(160,871,017)**	**13.58%**

The ACOSS shows that all classes, except Large General, are in a deficit position, requiring a revenue increase to reach their cost to serve. The Large General class is in a surplus position and would require a decrease to move to its cost to serve.

Q. PLEASE DESCRIBE THE RESULTS SHOWN IN TABLE 4.

A. Table 4, shown below, presents the current rate of return, revenue-to-cost ratio, and parity ratio by customer class based on the Company's ACOSS.

Table 4 – Current Rate of Return and Ratios

Customer Classes	Current Rate of Return	Current Revenue to Cost Ratio	Current Parity Ratio
Residential	5.8%	0.88	1.00
Small General	3.1%	0.79	0.90
Medium General	5.3%	0.83	0.94
Large General	18.1%	1.38	1.57
Mainline Service	0.6%	0.72	0.82
Total System	**6.0%**	**0.88**	**1.00**

The revenue-to-cost ratio compares the revenues collected from each class to the cost of serving that class, where values below 1.00 indicate under-recovery and values above 1.00 indicate over-recovery. The parity ratio reflects each class's rate of return relative to the system average. As shown, most customer classes, including Residential,

[4] See Exhibit No. 11, Schedule 1, lines 13, 52, 57, 24, 26, and 27.
Percent Change = Class Revenue (Deficiency)/Sufficiency ÷ Current Revenues

Small General, Medium General, and Mainline Service, are contributing less than their cost of service, while the Large General class is contributing more than its cost of service. Overall, the system revenue-to-cost ratio of 0.88 indicates that current revenues are below the cost of providing service.

Q. HAVE YOU PREPARED MORE DETAILED REPORTS OF PEOPLES' ACOSS RESULTS?

A. Yes, additional details are included in **Peoples Exhibit No. 11**. Schedule 4 "Account Balances and Allocation Methods" of **Peoples Exhibit No. 11** includes revenue requirement information by FERC account provided by Peoples and shows assigned functions, categories, and allocation factors. Schedule 3 "Cost of Service Allocation Study Detail by Account" of **Peoples Exhibit No. 11** presents the resulting allocations by customer class of Peoples' proposed revenue requirement based on the results of the computations included in the ACOSS.

VI. PRINCIPLES OF SOUND RATE DESIGN

Q. PLEASE IDENTIFY THE RATE DESIGN PRINCIPLES UTILIZED IN DEVELOPING THE COMPANY'S RATE DESIGN PROPOSALS.

A. 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. [5] Each of these principles plays an important role in analyzing the rate design proposals of Peoples and provides a roadmap that helps guide utilities and regulators when considering how to

[5] James Bonbright et al. Principles of Public Utility Rates, Public Utilities Reports, Inc. 2nd Edition, 1988.

achieve utility rates that are fair, efficient, practical, and reasonable. 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/Gradualism: 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.

In addition, these principles are consistent with Pennsylvania practice and precedent, including the *Lloyd* decision,[6] 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.

Q. HOW ARE THESE PRINCIPLES TRANSLATED INTO THE DESIGN OF RATES?

A. The overall rate design process, which includes both the apportionment of the revenues to be recovered among rate classes and the determination of rate structures within rate

[6] *Lloyd v. Pa. P.U.C.*, 904 A.2d 1010 (Pa. Cmwlth. 2006), *appeal denied*, 591 Pa. 676, 916 A.2d 1104 (2007) ("*Lloyd*").

classes, consists of finding a reasonable balance between the above-described criteria or guidelines that relate to the design of utility rates. Economic, regulatory, historical, and social factors all enter the process. In other words, both quantitative and qualitative information are evaluated before reaching a final rate design determination. Out of necessity, the rate design process must be, in part, influenced by judgmental evaluations.

VII. PEOPLES' REVENUE APPORTIONMENT

Q. PLEASE DESCRIBE THE APPROACH USED BY PEOPLES TO ALLOCATE ITS PROPOSED $160.9 MILLION BASE RATE REVENUE INCREASE AMONG ITS CUSTOMER RATE CLASSES.

A. Peoples' proposed allocation of the revenue increase is informed by the results of the ACOSS and reflects a deliberate effort to move all rate classes closer to the overall system rate of return, thereby reducing the subsidies that currently exist between classes. This approach is consistent with long-standing regulatory practice and precedent, including the *Lloyd* decision and the Commission's Order on remand approving the settlement in that case.

The benchmark option evaluated under Peoples' proposed total revenue level was to adjust the revenue level for each customer class so that the revenue-to-cost for each class was equal to 1.00. This is shown in **Peoples Natural Gas Exhibit No. JDT-3**, Scenario 1, where the changes in each classes' revenues would be set to their deficiency or surplus. It was decided that this fully cost-based option was not the preferred solution to the interclass revenue issue, given the large decrease that was required for the Large General class which would result in more of an increase needed from the other classes,

and the fact that the vast majority of revenues within the Mainline Service class are from negotiated contract customers. After discussions with the Company, the increase proposed in this case was allocated based on a desire to move toward full parity over time, while addressing issues of gradualism and recognizing these dynamics with the Large General and Mainline Service classes. To accomplish this, the Company first set Large General and Mainline Service's proposed revenues to their current revenues. Second, capped the increase to the Small General class to 1.5 times the overall system increase and set the targeted increase for Residential and Medium General to their cost to serve. Finally, allocated the additional increase required between Residential and Medium General based on the relative targeted revenue increase for each class, which ultimately results in Residential's increase at 1.05 times the overall system increase and Medium General at 1.25 times. While there are various yardsticks used to measure the degree of movement toward cost of service, the Company evaluated two metrics: (1) the percentage movement towards the system rate of return; and (2) the reduction in the subsidies occurring between classes. With these considerations, the Company is proposing the revenue changes shown in Table 5 below.

Table 5 – Proposed Class Revenue Apportionment

Customer Classes	Current Revenues	Proposed Revenue Change	Proposed Percentage Change	Proposed Rate of Return	Proposed Revenue to Cost Ratio (Parity Ratio)
Residential	$ 875,171,173	$ 118,163,447	13.50%	8.1%	0.99
Small General	$ 116,045,549	$ 21,443,151	18.48%	6.6%	0.94
Medium General	$ 108,167,260	$ 21,264,419	19.66%	8.0%	0.99
Large General	$ 72,051,809	$ -	0.00%	15.5%	1.38
Mainline Service	$ 13,178,274	$ -	0.00%	1.0%	0.74
Total	**$ 1,184,614,065**	**$ 160,871,017**	**13.58%**		

Q. TO WHAT DEGREE DOES THE COMPANY'S PROPOSED REVENUE APPORTIONMENT MOVE THE CLASSES TOWARD THEIR COST OF SERVICE?

A. The Company's proposed revenue apportionment results in the reduction of the existing rate subsidies and excesses among the Company's rate classes, moving classes toward the overall system rate of return. From a class cost of service standpoint, this type of class movement and reduction in class rate subsidies is desirable, as it brings class revenues and rates closer to the indicated cost of service for each rate class.

Table 6 below compares the current and proposed rates of returns and parity ratios. The Company's proposal moves the return for all rate classes closer to the Company's proposed return.

Table 6 - Comparison of Relative Rate of Return by Rate Class[7]

Customer Classes	Current Total Revenues	Total Revenues at Proposed	Current Return	Proposed Return	Current Revenue to Cost Parity Ratio	Proposed Revenue to Cost Parity Ratio
Residential	$ 875,171,173	$ 994,520,060	5.8%	8.1%	1.00	0.99
Small General	$ 116,045,549	$ 137,617,255	3.1%	6.6%	0.90	0.94
Medium General	$ 108,167,260	$ 129,662,826	5.3%	8.0%	0.94	0.99
Large General	$ 72,051,809	$ 72,454,884	18.1%	15.5%	1.57	1.38
Mainline Service	$ 13,178,274	$ 13,530,978	0.6%	1.0%	0.82	0.74
Total System	**$ 1,184,614,065**	**$ 1,347,786,003**	**6.0%**	**8.2%**	**1.00**	**1.00**

VIII. PEOPLES' RATE DESIGN

Q. PLEASE SUMMARIZE THE RATE DESIGN CHANGES PEOPLES HAS PROPOSED IN THIS RATE PROCEEDING.

A. In general, Peoples' rate design strategy is to make incremental movements toward reflecting the Company's relative cost of serving each rate class to provide natural gas distribution service to those customers. Therefore, Peoples has proposed to increase the

[7] Exhibit D, Schedule 1, lines 10, 52, 24, 70, 27, and 73.

customer charge for its current tariff schedules as shown in Table 7 below, with the remaining proposed increase to be recovered in the volumetric charge.

Table 7 – Fixed Monthly Customer Charges

Rate Schedule	Annual Consumption	Current	Proposed
Residential	All	$ 16.80	$ 26.00
SGS	0 to 499 Mcf	$ 22.00	$ 32.14
SGS	500 to 999 Mcf	$ 44.00	$ 64.28
MGS	1,000 to 2,499 Mcf	$ 101.00	$ 110.00
MGS	2,500 to 24,999 Mcf	$ 145.00	$ 158.00
LGS	25,000 to 49,999 Mcf	$ 940.00	$ 987.00
LGS	50,000 to 99,999 Mcf	$ 1,465.00	$ 1,538.00
LGS	100,000 to 199,999 Mcf	$ 2,130.00	$ 2,237.00
LGS	Over 200,000 Mcf	$ 5,630.00	$ 5,912.00
MLS	Over 500,000 Mcf	$ 5,630.00	$ 5,912.00

For Rates LGS and MLS the proposed monthly customer charge represents the current monthly fixed charge which includes both the current monthly customer charge, the roll-in of the Distribution System Improvement Charge ("DSIC") and the Tax Repair Surcredit ("TRS") riders rounded to the nearest whole dollar.

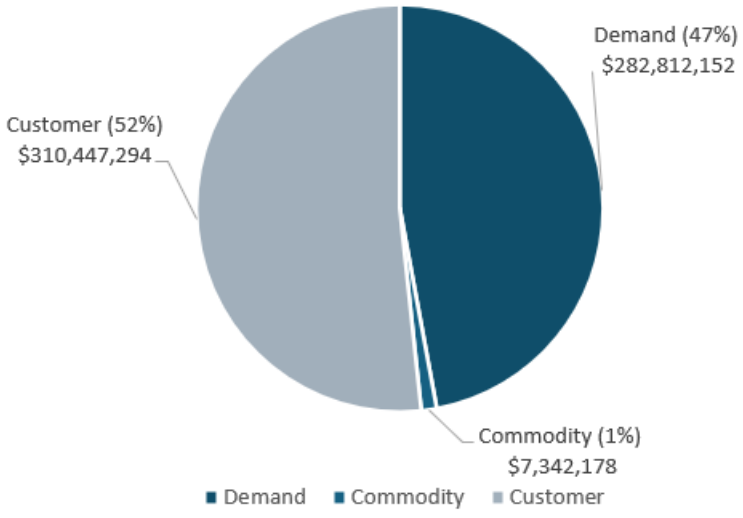
Q. HAS THE COMPANY PREPARED A COMPARISON OF THE COMPANY'S CURRENT AND PROPOSED RATES AND RESULTING REVENUES BY RATE CLASS?

A. Yes. **Peoples Natural Gas Exhibit No. JDT-4** – Rate Design provides the calculation of revenues using current and proposed rates. In addition, **Peoples Exhibit No. 3 – Proof of Revenue**, sponsored by Company witness Dawn M. Folks, whose Direct Testimony is **Peoples Statement No. 4**, presents a detailed comparison of current and proposed revenues for each of Peoples' rate classes.

Q. HOW DOES THE ACOSS SUPPORT THE PROPOSED INCREASES TO FIXED MONTHLY CHARGES?

A. Atrium's ACOSS model allows for developing the total revenue requirement by functions and classifications. As such, we can see directly the revenue requirement associated with the customer classification and the respective functions that form this revenue requirement. **Peoples Exhibit No. 11, Schedule 2** provides the customer-related unit cost per customer per month, for Rates RS, SGS, MGS, LGS, MLS and provides useful insights on the fixed monthly costs of providing service to these customers, inclusive of both customer-related costs and demand-related costs. Figure 6 below indicates that 1% of the Residential revenue requirement, excluding gas costs, is categorized as "commodity" in the ACOSS, which primarily represents costs associated with storage and gathering before any credit from the Company's producers.

Figure 6 - Residential - Total Revenue Requirement by Component



Q. WHY ARE SETTING FIXED MONTHLY CHARGES MORE IN ALIGNMENT WITH THE FIXED COST OF SERVICE AN IMPORTANT OUTCOME OF RATEMAKING?

A. These proposed fixed monthly customer charges help to reduce customer bill volatility, alleviate a significant portion of the instability in the Company's margin recovery, are fair to customers, are easily understood, convey more appropriate price signals with respect to recovery of fixed utility costs, benefit low-income customers that have higher than average use, and are not regressive in application to low-income customers who may have little control over their use of energy and are negatively impacted when recovering more costs in volumetric charges.

Establishing higher monthly fixed charges helps to equalize the contribution each customer within a class makes towards recovery of the fixed costs attributable to this class. This method of cost recovery is preferable to including such costs in the volumetric charges, which has the effect of causing some customers to pay too much while others pay too little. The customer charges provide for recovery of a portion of the Company's fixed costs, which are incurred solely because of the existence of customers connected to the system. These costs, such as the expense of reading meters and billing, occur regardless of whether natural gas is used and are not related to demands placed on the system. The proposed customer charge increases will also help to ensure the Company's recovery of a greater portion of its fixed costs of providing service. In as much as costs are not related to usage, they should be recovered, to the extent possible, through a tariff mechanism that does not depend upon volumetric billing.

In terms of understandability, customers easily recognize fixed cost charges and are used to these pricing structures in their everyday lives. Because these costs do not vary with the customer's usage, it is perfectly understandable that the charge should not vary as well.

Q. HAS THE COMPANY PREPARED BILL IMPACT ANALYSES COMPARING CUSTOMER BILLS UNDER CURRENT AND PROPOSED RATES?

Yes. **Peoples Natural Gas Exhibit No. JDT-5**, Bill Comparisons provides average monthly and annual bill comparisons for each rate class under current and proposed rates in table and chart formats.

IX. WNA MECHANISM

Q. WHAT IS THE COMPANY'S PROPOSAL REGARDING WNA IN THIS PROCEEDING?

A. The Company is not proposing to make any structural modifications to the WNA. The Company is only updating the WNA normalization period to rely on a 65-year regression-based methodology, consistent with the normalization approach used to develop billing determinants in this rate case.

Q. WHAT IS THE COMPANY'S WNA?

A. The WNA is a Commission-approved adjustment mechanism that reconciles distribution revenues to the level that would have been collected under normal weather conditions. It compares actual HDD to normal HDD embedded in base rates and adjusts revenues for deviations during the heating season. The mechanism operates symmetrically, producing surcharges in warmer-than-normal periods and credits in colder-than-normal periods.

Q. WHY IS A WNA MECHANISM NECESSARY UNDER THE COMPANY'S RATE STRUCTURE?

A. The Company's rate design recovers a substantial portion of fixed distribution costs through volumetric charges. Because volumetric revenues are established using normalized billing determinants, deviations in actual weather from normal conditions can result in under-recovery in warm winters and over-recovery in cold winters. The WNA stabilizes recovery of authorized distribution revenues attributable to weather-sensitive usage while operating symmetrically to protect customers when weather is colder than normal. In other words, the WNA does not guarantee earnings; it provides the Company with a reasonable opportunity to recover its authorized revenue requirement while protecting customers from additional charges in colder-than-normal winters.

Q. CAN YOU ELABORATE ON THE RELATIONSHIP BETWEEN FIXED COSTS AND USAGE-BASED RECOVERY?

A. The Company incurs significant fixed costs to design, construct, maintain, and operate its distribution system. These costs do not vary meaningfully with short-term changes in customer usage. However, a substantial portion of those fixed costs is recovered through volumetric distribution charges that vary with consumption. When winter weather is warmer than normal, usage declines and fixed costs may be under-recovered. When weather is colder than normal, revenues may exceed normalized levels. The WNA addresses this mismatch by adjusting revenues to reflect normalized weather assumptions approved in rates.

Q. COULD THE COMPANY ELIMINATE WEATHER-RELATED REVENUE VARIABILITY THROUGH A DIFFERENT RATE DESIGN?

A. A Straight-Fixed-Variable ("SFV") rate design would reduce weather sensitivity by recovering fixed costs through the monthly fixed charge rather than volumetric rates. However, as previously indicated, the Company's current rate structure continues to recover a substantial portion of fixed distribution costs through volumetric charges. The WNA serves as a targeted and limited mechanism to address weather-related variability within that existing rate design framework.

Q. WHEN DID THE COMMISSION APPROVE THE COMPANY'S WNA?

A. The Company's current WNA was approved by the Commission in the Company's last base rate proceeding, that was approved on September 12, 2024 in Docket No. R-2023-3044549. The WNA was included in a non-unanimous settlement agreement that was opposed by the Office of Consumer Advocate ('OCA"). As a result, the WNA was fully litigated by Peoples and OCA, including hearings, cross-examination, Main and Reply Briefs, Exceptions and Reply Exceptions.

Q. PLEASE DESCRIBE THE KEY FEATURES OF THE CURRENTLY APPROVED WNA.

A. The currently approved WNA:

- Applies to the Residential and Small/Medium General Service classes;
- Operates during the October through May heating season;
- Includes a 3% deadband;
- Is calculated on a bills-rendered basis;
- Is presented as a separate line item on customer bills;

- Includes a limiter for bills rendered in May such that the WNA adjustment will not exceed 100% of the billed distribution amount (delivery charge plus customer charge) for that same billing period; and
- Requires annual reporting of billed WNA revenues, actual and normal HDD, and bill impact information.

Q. HAS THE COMPANY COMPLIED WITH THE WNA REQUIREMENTS ESTABLISHED IN DOCKET NO. R-2023-3044549?

A. Yes. The Company has implemented the WNA consistent with the Commission-approved settlement, including the operational parameters and reporting requirements described above. In accordance with those requirements, the Company filed its annual WNA report for the 2024–2025 heating season on August 29, 2025, which is available on the Commission's website at: https://www.puc.pa.gov/pcdocs/1893389.pdf

Q. WHAT NORMALIZATION METHODOLOGY WAS APPROVED IN DOCKET NO. R-2023-3044549?

A. The HDD values reflected in the settlement are consistent with the blended approach, which averages results from a 65-year regression and a 20-year average HDD normalization.

Q. WHY IS THE COMPANY PROPOSING TO CHANGE THE WNA NORMALIZATION PERIOD?

A. First, the Company is proposing a new normalization period as its Tariff requires that it update the HDDs in its next base rate proceeding. The Company is proposing this change to ensure methodological consistency between the weather normalization assumptions used to establish base-rate billing determinants and those used in the WNA.

When rates are set, billing determinants are normalized to reflect "normal" weather conditions. The WNA then compares actual weather to that same normalized baseline. If different normalization methodologies are used for rate-setting and WNA reconciliation, the mechanism could over- or under-correct relative to the assumptions embedded in customer rates. That outcome would be inconsistent with the WNA's purpose, which is to reconcile revenues to the same weather conditions used to establish rates.

In this proceeding, the Company is normalizing billing determinants using a 65-year regression framework. Aligning the WNA normalization methodology with that same 65-year regression ensures that both base rates and subsequent WNA calculations rely on the same weather foundation. This approach:

- Maintains internal consistency between revenue requirement development and WNA reconciliation;
- Avoids unintended distortions that could arise from using different normalization baselines;
- Preserves the integrity of the matching principle by ensuring that revenue assumptions and reconciliation mechanisms rely on the same weather foundation; and
- Enhances transparency and predictability for both customers and the Commission.

Q. WHY DOES UPDATING THE NORMALIZATION PERIOD TO A 65-YEAR REGRESSION DOES NOT ELIMINATE THE NEED FOR A WNA?

A. Even when billing determinants are normalized using a statistically robust long-term regression, actual weather will continue to vary from normal conditions from year to year. The WNA remains necessary to address annual deviations between actual HDD and normal HDD assumptions embedded in rates. The regression improves the definition of

"normal," but it does not eliminate weather variability. The WNA continues to function as a symmetric mechanism that reconciles revenues for deviations from that normal baseline.

Q. WHY IS THE COMPANY NOT PROPOSING ANY MODIFICATIONS TO THE WNA AT THIS TIME?

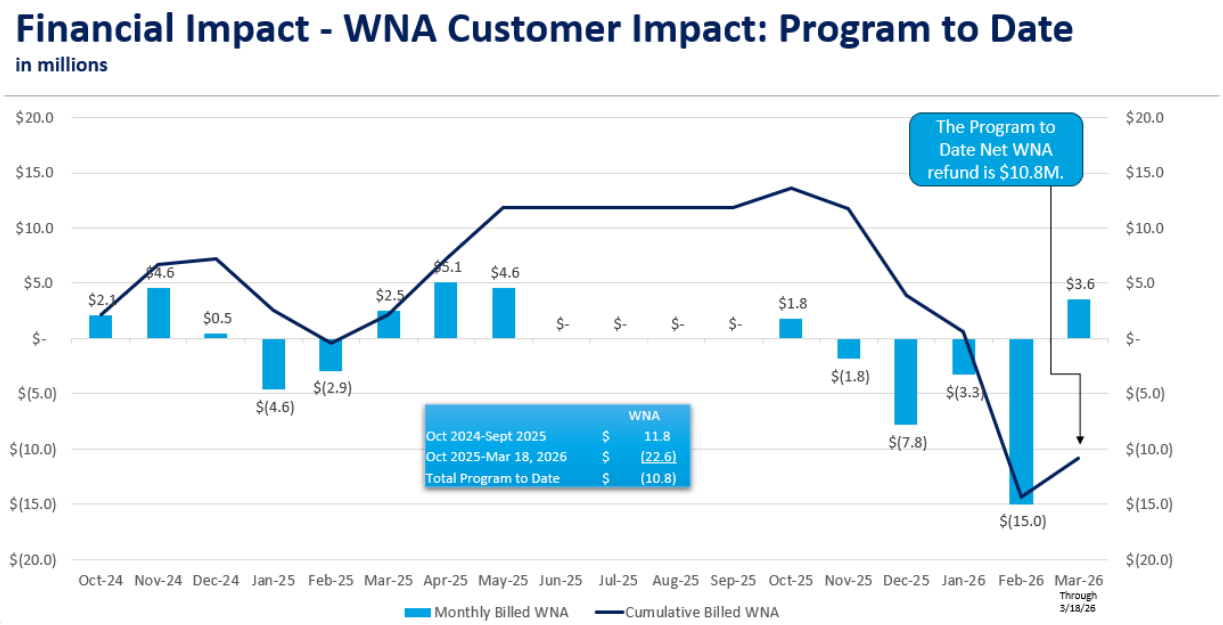
A. The Company has carefully evaluated the performance of its WNA since approval and has monitored developments in Pennsylvania regarding similar mechanisms, including the Commission's recent decision approving continuation of Columbia Gas of Pennsylvania's WNA. Based on that review and the Company's own reports, the existing WNA structure is operating as intended. Customer acceptance has been satisfactory with only two formal complaints since implementation. The mechanism has functioned symmetrically, producing charges during warmer-than-normal conditions and credits during colder-than-normal conditions, consistent with its design. Moreover, the data shows that during the current colder-than-normal heating season, low-income residential customers are receiving credits in the same proportion as other residential customers. This confirms that the mechanism operates neutrally across the residential class and does not disproportionately burden vulnerable customers. Accordingly, the Company believes that the current WNA structure, including its 3% deadband, limited class applicability, seasonal operation, and May limiter, continues to provide appropriate customer protections. For that reason, the Company is proposing only the update of the normal HDDs and is not seeking any broader structural modifications.

Q. WHAT HAS THE COMPANY'S EXPERIENCE BEEN WITH THE WNA SINCE ITS APPROVAL?

A. The Company's experience demonstrates that the mechanism operates symmetrically.

- The 2024-2025 heating season was warmer than normal, resulting in net WNA charges to customers to address weather-driven revenue shortfalls.
- The 2025-2026 heating season, through February, has been colder than normal, resulting in net WNA credits to customers.

These results illustrate that the WNA does not guarantee revenues or earnings. Rather, it adjusts for deviations from normal weather in either direction; therefore, operating symmetrically.



As noted in the table above, through mid-March 2026, the WNA has provided customers with a total net credit of $10.8 million since inception. During this past winter, which has been much colder than normal, the WNA has provided customers with a credit of $22.6 million as of mid-March 2026.

Q. HOW DOES THE PROPOSED UPDATE ALIGN WITH COMMISSION POLICY REGARDING ALTERNATIVE RATEMAKING MECHANISMS?

A. As shown in **Peoples Natural Gas Exhibit No. JDT-6**, the proposal satisfies the Commission's Statement of Policy at Docket No. M-2015-2518883, including symmetry, customer protections, transparency, limited scope, and consistency with cost recovery principles. The Company is not expanding or redesigning the mechanism; it is simply aligning normalization methodology to ensure consistency normal HDDs between base-rate (revenue requirement) development and WNA operation. All consumer protections previously approved by the Commission remain in place.

Q. ARE WNA MECHANISMS COMMON IN THE UTILITY INDUSTRY?

A. Yes. Weather normalization mechanisms are widely used across the United States to stabilize revenues and customer bills in the presence of weather variability. They are a well-established regulatory tool and have been approved for multiple Pennsylvania gas utilities.

X. CONCLUSION

Q. PLEASE SUMMARIZE YOUR CONCLUSIONS AND RECOMMENDATIONS FOR PEOPLES' ACOSS, CLASS REVENUES, AND RATE DESIGN.

A. I recommend that the Commission approve the following:

- The Company's 65-year regression-based HDD trend method, which provides a transparent, data-driven estimate of normal weather for the FPFTY and supports consistent, forward-looking normalization of weather-sensitive usage.
- The Company's customer forecasts and weather-normalized usage estimates developed for the FPFTY based on statistically sound, data-driven methods, resulting

in a reasonable set of billing determinants for use in setting just and reasonable rates.

- The Company's proposed ACOSS, as a realistic reflection of cost causation and the design and operating characteristics of the Company's distribution system, and as a guide to evaluate and set Peoples' class revenues and rate design in this proceeding.
- The Company's proposed apportionment of revenues to its rate classes, because it reasonably balances the various criteria that the Company considered in the revenue apportionment process and moves classes towards their cost to serve.
- The rate design proposed by the Company, including the proposed fixed monthly customer charge increases, because it reasonably balances key rate design objectives I presented earlier in my testimony, including: (1) achieving fair and equitable rate levels that are reflective of the cost to serve; (2) avoiding undue discrimination between and within rate classes; (3) developing rates that are stable and understandable; (4) creating economically efficient pricing for delivery service; (5) encouraging conservation and efficient use; and (6) recovering the revenue requirement in a manner that maintains revenue stability and minimizes year-to-year under- or over-collections.
- The Company's proposed WNA update for the weather normalization method, is consistent with the Company's tariff and the updated weather method is narrow, reasonable, and supported by operational experience. Peoples' WNA mechanism and the updated weather normalization method used (1) maintains all Commission-approved customer protections; (2) demonstrates symmetric operation based on actual heating season results; (3) preserves methodological consistency between billing determinant normalization and WNA calculations; and (4) supports stable recovery of authorized distribution revenues without expanding the mechanism's scope.

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes, it does.

John D. Taylor

CEO

Mr. John D. Taylor is the Co-Founder and Chief Executive Officer of Atrium Economics and a senior regulatory economist with more than twenty years of experience advising electric and natural gas utilities across the United States and Canada. Mr. Taylor has served as a lead expert in rate and regulatory proceedings across more than 20 jurisdictions in the United States and Canada. His testimony has been presented before the Federal Energy Regulatory Commission, numerous state public utility commissions, provincial utility regulators, and trial courts.

He has testified on matters including revenue requirements, class cost of service, advanced rate design, revenue stabilization mechanisms, affiliate transactions, demand forecasts, return on equity, lead lag studies, audit testing, and infrastructure cost recovery. In addition to matters in which he was the lead witness, he has supported over one hundred engagements for other expert witnesses, contributing to the development and defense of analytical models, regulatory strategy, and evidentiary submissions.

Mr. Taylor's experience spans vertically integrated electric utilities, gas distribution utilities, transmission providers, pipeline operators, municipally owned utilities, and multi-state holding companies. He has also served as market monitor for ISO New England's capacity market and has supported wholesale power purchase agreement evaluations and generation feasibility and prudence analyses. He regularly advises executive leadership and boards on regulatory strategy, risk allocation, revenue stability, infrastructure investment, and long-term rate design considerations.

In addition to his consulting leadership, Mr. Taylor served as Chief Executive Officer of a non-destructive testing and industrial inspection firm serving the power generation, petrochemical, and heavy industrial sectors. That role provided direct experience in capital-intensive infrastructure operations, asset integrity management, maintenance planning, safety compliance, and operational risk oversight. This operating perspective informs his work in utility capital planning, infrastructure expansion review, and regulatory cost recovery.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

20

RELEVANT EXPERTISE

Revenue Requirements & Capital Recovery, Class Cost of Service & Advanced Rate Design, Revenue Stabilization Mechanisms, Demand Forecasting & Resource Planning, Natural Gas & Pipeline Infrastructure Analysis, Return on Equity & Capital Structure, Affiliate Transactions & Operational Audits, Transmission & FERC Matters, Transaction Advisory & Regulatory Due Diligence

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
- Maryland Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- North Carolina – Brunswick Superior Court
- Oregon Public Utility Commission
- Ohio Public Utility Commission
- Pennsylvania Public Utility Commission
- South Carolina Public Service Commission
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- Public Service Commission of West Virginia

CANADA:

- Alberta Utilities Commission
- British Columbia Utilities Commission
- Ontario Energy Board

REPRESENTATIVE EXPERIENCE

RATE DESIGN AND REGULATORY PROCEEDINGS

Mr. Taylor has extensive experience developing and evaluating utility revenue requirements, including review of test year construction, pro forma adjustments, operating expense normalization, capital investment recovery, depreciation and amortization treatment, and cash working capital analyses, including lead-lag studies. He has assessed prudence and regulatory treatment of major capital programs, infrastructure modernization initiatives, and incremental investment proposals. In addition, Mr. Taylor has designed and evaluated revenue stabilization mechanisms, including Weather Normalization Adjustments, Revenue Adjustment Mechanisms, and other forms of decoupling and revenue recovery tools. His work includes back-casting analyses, risk assessment modeling, and evaluation of tradeoffs between customer bill stability and utility revenue certainty. He has testified regarding both the technical design and policy implications of such mechanisms in contested regulatory proceedings.

CLASS COST OF SERVICE AND RATE DESIGN

Mr. Taylor has extensive experience developing and defending embedded and marginal class cost of service studies in contested regulatory proceedings across the United States and

Canada. His work includes functionalization, classification, and allocation of utility costs; development of jurisdictional and class revenue requirements; and evaluation of fixed-variable cost recovery methodologies. He has designed and evaluated residential, commercial, and industrial rate structures, including demand-based rates, time-of-use designs, economic development tariffs, and revenue apportionment strategies. Mr. Taylor has also assessed rate stability, equity considerations, and cost causation principles in the context of evolving load patterns, electrification, and policy-driven rate reforms.

DEMAND AND CUSTOMER FORECASTING

Mr. Taylor has extensive experience developing and evaluating demand and customer forecasting models for electric and natural gas utilities. His work includes econometric modeling of customer growth, usage normalization, peak demand forecasting, and weather-sensitive load analysis. He has assessed forecast methodologies for rate proceedings, infrastructure planning, and resource adequacy evaluations, including review of macroeconomic drivers, demographic trends, and end-use consumption patterns. Mr. Taylor has also evaluated forecast inputs used in capital planning, pipeline capacity assessments, LNG resource planning, and revenue requirement development. His experience includes back-casting analyses, scenario modeling, and sensitivity testing to assess forecast risk and regulatory defensibility. He has testified regarding forecast methodology, assumptions, and alignment with regulatory standards in contested proceedings.

RETURN ON EQUITY AND CAPITAL STRUCTURE

Mr. Taylor has provided testimony and advisory analysis regarding return on equity and capital structure for regulated electric and natural gas utilities in both transmission and distribution contexts. His work includes evaluation of regulatory capital structures, cost of capital components, and risk considerations associated with infrastructure investment, revenue stability mechanisms, and business model evolution. He has supported financial modeling in rate proceedings, including assessment of cash flow implications, earnings stability, and alignment between authorized returns and underlying business risk. Mr. Taylor has also evaluated the interaction between capital structure, revenue recovery mechanisms, and regulatory policy objectives, including the treatment of large capital programs and expansion initiatives.

TRANSACTION ADVISORY AND REGULATORY DUE DILIGENCE

Mr. Taylor has advised utilities and infrastructure stakeholders in connection with asset acquisitions, divestitures, and wholesale power supply evaluations. His transaction experience includes regulatory due diligence, evaluation of revenue requirements and rate structures, infrastructure risk assessment, and financial modeling to support investment decisions. Mr. Taylor has advised on regulated utility and energy infrastructure transactions, including buy-side and sell-side evaluation of utility operations and generation asset divestitures. His work has

included assessment of revenue requirements, rate structures, customer forecasts, regulatory risk, operational performance, and capital recovery considerations to support informed investment decisions. His advisory work has also included evaluation of comparable utility transactions, merger activity, and regulatory approval considerations affecting infrastructure investment decisions.

NATURAL GAS INFRASTRUCTURE & RESOURCE PLANNING EXPERIENCE

Mr. Taylor has extensive experience supporting natural gas utilities and pipeline operators in forecasting, peak demand planning, LNG resource evaluation, balancing mechanisms, transportation modeling, and line extension reviews. His work includes demand forecasting for local distribution companies, evaluation of peak day planning standards, LNG peaking facility analyses, storage utilization review, pipeline transport cost allocation, and balancing service design. He has evaluated integrated resource planning approaches, supply portfolio risk assessment, and incremental pipeline capacity expansion proposals. His experience includes review of expansion economics, regulatory treatment of new infrastructure investment, and cost recovery mechanisms associated with large capital programs. Mr. Taylor has also assessed alignment between demand forecasts, contracted capacity, storage strategy, and long-term system reliability objectives, providing analytical support for regulatory filings and board-level capital planning decisions.

AFFILIATE RELATIONSHIPS & PERFORMANCE REVIEWS

Mr. Taylor has led and supported affiliate transaction reviews, shared services cost allocation studies, and operational performance assessments in both U.S. and Canadian jurisdictions. His work includes evaluation of overhead allocation methodologies, overhead capitalization practices, and cost recovery treatment associated with corporate support functions, transmission-related shared assets, and early contractor engagement for major infrastructure projects. He has assessed capitalization rates, allocation between transmission and distribution functions, and cost attribution to regulated versus affiliate activities, ensuring consistency with regulatory standards and precedent. His experience includes shared assets studies, evaluation of contractor cost structures in large capital programs, and review of governance controls supporting regulatory compliance. In addition, Mr. Taylor has conducted operational audits and benchmarking analyses addressing operations and maintenance (O&M) and administrative and general (A&G) expenses. His work includes comparative peer analysis, assessment of cost drivers, and evaluation of organizational efficiency and cost discipline in regulated utility environments.

PROFESSIONAL EXPERIENCE

CO-FOUNDER & CHIEF EXECUTIVE OFFICER | ATRIUM ECONOMICS | 2020 – PRESENT

Leads a regulatory advisory firm serving electric and natural gas utilities across the United States and Canada. Serves as lead expert witness in rate and regulatory proceedings and oversees firm strategy, analytical methodology, and evidentiary quality control. Advises executive leadership and boards on revenue requirements, rate design, infrastructure investment, and regulatory risk.

CHIEF EXECUTIVE OFFICER | NOVA DATA TESTING | 2019 – 2026

Led a non-destructive testing and industrial inspection firm serving power generation and petrochemical facilities. Responsible for strategic planning, capital allocation, regulatory compliance, operational leadership, and risk oversight in asset-intensive, safety-sensitive environments. This operating experience informs his perspective on infrastructure investment and operations.

PRINCIPAL CONSULTANT | BLACK & VEATCH MANAGEMENT CONSULTING | 2015 – 2020

Led regulatory and financial advisory engagements for electric and gas utilities, including revenue requirements, class cost of service, affiliate transactions, and return on equity matters. Filed expert testimony and supported infrastructure transaction advisory and regulatory approval strategy.

SENIOR PROJECT MANAGER & PRINCIPAL | CONCENTRIC ENERGY ADVISORS | 2006 – 2015

Managed regulatory consulting engagements involving revenue requirements, cost allocation, and rate design across multiple jurisdictions. Led project teams, supported expert testimony, and contributed to business development and firm-wide analytical quality control initiatives.

EDUCATION

MASTER OF ARTS, ECONOMICS| AMERICAN UNIVERSITY | 2004 – 2006

Graduate coursework included econometrics, advanced microeconomics and macroeconomics, mathematical economics, monetary policy, and history of economic thought. Served as a teaching assistant for undergraduate microeconomics and macroeconomics courses.

BACHELOR OF ARTS, ENVIRONMENTAL ECONOMICS | UNIVERSITY OF NORTH CAROLINA AT ASHEVILLE | 2000 – 2004

Coursework emphasized the application of economic theory and quantitative analysis to environmental and resource issues, including statistics and applied modeling. Completed independent study examining the intersection of ethics and economic theory.

BOARD AND ADVISORY BOARDS

Treasurer, Board of Directors – The Outside Foundation (2023–Present)

Member – 278 Gateway Corridor Committee, Town of Hilton Head Island (2019–2022)

Richmond Advisory Board – Higher Achievement (2014–2015)

Peoples Natural Gas Company LLC
Gas Class Cost of Service Study: Average of Customer-Demand and Demand-Commodity Allocation of Distribution Mains
12 Months Ending December 31, 2027
Peoples Exhibit JDT-2 - Derivation of Total Gathering Cost of Service

Line No.	Description	Gathering System Amount
1	**Rate Base**	
2	Plant in Service	
3	Intangible Plant	$ 4,846,007
4	Production Plant	188,680,448
5	General Plant	7,253,614
6	Total Plant in Service	$ 200,780,069
7	Accumulated Reserve	
8	Intangible Plant	$ (2,928,577)
9	Production Plant	(65,793,263)
10	General Plant	(2,371,079)
11	Total Accumulated Reserve	$ (71,092,920)
12	Other Rate Base Items	
13	Materials and Supplies	$ 173,931
14	Prepayments	142,288
15	Cash Working Capital	1,342,127
16	Deferred Income Taxes	3,396,064
17	Total Other Rate Base Items	$ 5,054,409
18	**Total Rate Base**	**$ 134,741,559**
19	Required Return	8.23%
20	**Return on Ratebase**	**$ 11,087,516**
21	**Expenses**	
22	Natual Gas Production and Gathering	$ 12,417,071
23	Administrative and General	2,964,339
24	Depreciation and Amortization Expense	5,899,038
25	Taxes Other Than Income	565,414
26	**Total Expenses**	**$ 21,845,862**
27	Income Taxes at Proposed Rates	$ -
28	**Total Gathering Cost of Servcie**	**$ 32,933,378**
29	**Gathering Service Revenues**	
30	Gathering Revenue at Current Rates	$ 7,404,749
31	Gathering Revenue at Proposed Rates (FPFTY)	$ 8,551,629

Peoples Natural Gas Company LLC
Gas Class Cost of Service Study: Average of Customer-Demand and Demand-Commodity Allocation of Distribution Mains
12 Months Ending December 31, 2027
Peoples Exhibit JDT-3 - Proposed Class Revenue Apportionment

Line No.	Category Description	Total System	Residential	Small General	Medium General	Large General	Mainline Service
1	Total Rate Base	$ 5,728,767,833	$ 4,075,749,520	$ 601,933,351	$ 672,002,216	$ 305,362,042	$ 73,720,705
2	**Revenue at Current Rates**						
3	Base Rate Revenue	$ 616,555,782	$ 431,488,517	$ 54,788,815	$ 65,431,384	$ 57,668,118	$ 7,178,949
4	Other	-	-	-	-	-	-
5	**Subtotal Base Revenue at Current Rates**	$ 616,555,782	$ 431,488,517	$ 54,788,815	$ 65,431,384	$ 57,668,118	$ 7,178,949
6	Gas Cost Revenue	$ 505,919,390	$ 399,536,779	$ 57,104,184	$ 38,013,446	$ 7,080,512	$ 4,184,468
7	Riders and Other Revenue	62,138,892	44,145,876	4,152,549	4,722,430	7,303,180	1,814,856
8	**Total Revenue at Current Rates**	**$ 1,184,614,065**	**$ 875,171,173**	**$ 116,045,549**	**$ 108,167,260**	**$ 72,051,809**	**$ 13,178,274**
9	**Current Revenue to Cost Ratio**	0.88	0.88	0.79	0.83	1.38	0.72
10	**Current Parity Ratio**	1.00	1.00	0.90	0.94	1.57	0.82
11	**Scenario 1: Revenues at Equalized Rates of Return**						
12	Margin Revenue Increase/(Decrease)	$ 160,871,017	$ 123,781,790	$ 30,162,380	$ 22,275,482	$ (20,108,804)	$ 4,760,169
13	Base Revenue at Current Rates	616,555,782	431,488,517	54,788,815	65,431,384	57,668,118	7,178,949
14	Gas Cost Revenue	505,919,390	399,536,779	57,104,184	38,013,446	7,080,512	4,184,468
15	Riders and Other Revenue	64,439,814	45,331,316	4,281,105	4,953,577	7,706,254	2,167,561
16	**Total Revenue at Equalized Rates of Return**	$ 1,347,786,003	$ 1,000,138,402	$ 146,336,484	$ 130,673,890	$ 52,346,079	$ 18,291,147
17	**Rate Revenue at Equalized Rates of Return**	$ 777,426,799	$ 555,270,307	$ 84,951,195	$ 87,706,866	$ 37,559,313	$ 11,939,118
18	**% Increase of Total Revenues**	13.6%	14.1%	26.0%	20.6%	-27.9%	36.1%
19	**% Increase of Margin Revenues**	26.1%	28.7%	55.1%	34.0%	-34.9%	66.3%
20	**Resulting Revenue to Cost Ratio (Parity Ratio)**	1.00	1.00	1.00	1.00	1.00	1.00
21	**Scenario 2: Equal Percentage Increase on Service Revenue**						
22	Percent Increase	26.1%	26.1%	26.1%	26.1%	26.1%	26.1%
23	Margin Revenue Increase/(Decrease)	$ 160,871,017	$ 112,583,481	$ 14,295,434	$ 17,072,280	$ 15,046,698	$ 1,873,123
24	Base Revenue at Current Rates	616,555,782	431,488,517	54,788,815	65,431,384	57,668,118	7,178,949
25	Gas Cost Revenue	505,919,390	399,536,779	57,104,184	38,013,446	7,080,512	4,184,468
26	Riders and Other Revenue	64,439,814	45,331,316	4,281,105	4,953,577	7,706,254	2,167,561
27	**Total Revenue at Equal Percentage Increase**	$ 1,347,786,003	$ 988,940,094	$ 130,469,538	$ 125,470,688	$ 87,501,582	$ 15,404,101
28	**Rate Revenue at Equal Percent Increase**	$ 777,426,799	$ 544,071,998	$ 69,084,249	$ 82,503,664	$ 72,714,816	$ 9,052,072
29	**Resulting Revenue to Cost Ratio (Parity Ratio)**	1.00	0.99	0.89	0.96	1.67	0.84
30	**Scenario 3: Moderated based on Current Parity Ratio**						
37	Multiple of System Increase		1.05	1.50	1.25	-	-
38	Percent Increase		27.39%	39.14%	32.50%	0.00%	0.00%
39	Margin Revenue Increase/(Decrease)	$ 160,871,017	$ 118,163,447	$ 21,443,151	$ 21,264,419	$ -	$ -
40	**Total Margin Revenue at Proposed Rates**	**$ 777,426,799**	**$ 549,651,964**	**$ 76,231,966**	**$ 86,695,802**	**$ 57,668,118**	**$ 7,178,949**
41	Gas Cost Revenue	505,919,390	399,536,779	57,104,184	38,013,446	7,080,512	4,184,468
42	Riders and Other Revenue	64,439,814	45,331,316	4,281,105	4,953,577	7,706,254	2,167,561
43	**Total Revenue at Proposed Rates**	**$ 1,347,786,003**	**$ 994,520,060**	**$ 137,617,255**	**$ 129,662,826**	**$ 72,454,884**	**$ 13,530,978**
44	**% Increase of Total Revenues**	13.6%	13.5%	18.5%	19.7%	0.0%	0.0%
44	Percent Increase on Base Rate Margin	26.1%	27.4%	39.1%	32.5%	0.0%	0.0%
45	**Proposed Revenue to Cost Ratio (Parity Ratio)**	1.00	0.99	0.94	0.99	1.38	0.74

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-4 - Rate Design

		Current Base Rates	Current Plus Rolled-in Riders	Billing Determinants	Current Base Revenue	Rolled-in Rider Revenue					Revenue Increase	Target Base Revenue	Proposed Rates	Proposed Base Revenue
						STAS	MFC	USR	GPC	DSIC				
Residential														
Customer Charge	Sales	$16.80	$17.64	6,587,212	$ 110,665,160	$ -	$ -	$ -	$ -	$ 5,533,258			$26.00	$ 171,267,510
	CAP	$16.80	$17.64	468,120	$ 7,864,416	$ -	$ -	$ -	$ -	$ 393,221			$26.00	$ 12,171,120
	Transport	$16.80	$17.64	774,040	$ 13,003,878	$ -	$ -	$ -	$ -	$ 650,194			$26.00	$ 20,125,049
Delivery Charge	Sales	$5.3537	$5.6962	46,273,106	$ 247,732,328	$ 171,210	$ 965,606	$ (249,875)	$ (550,650)	$ 15,514,447			$6.6359	$ 307,063,704
	CAP	$5.3537	$5.7016	4,103,527	$ 21,969,054	$ 15,183	$ 85,631	$ -	$ (48,832)	$ 1,375,831			$6.6359	$ 27,230,597
	Transport	$5.3537	$5.6815	5,650,985	$ 30,253,681	$ 20,909	$ 28,384	$ (30,515)	$ -	$ 1,833,801			$6.6359	$ 37,499,375
Residential Total					$ 431,488,517	$ 207,302	$ 1,079,621	$ (280,390)	$ (599,482)	$ 25,300,752	$ 118,163,447	$ 575,359,766		$ 575,357,355
Commercial SGS														
Customer Charge														
0 to 499 MCF/Yr	Sales	$22.00	$23.10	425,015	$ 9,350,338	$ -	$ -	$ -	$ -	$ 467,517			$32.14	$ 13,659,994
500 to 999 MCF/Yr	Sales	$44.00	$46.20	34,838	$ 1,532,876	$ -	$ -	$ -	$ -	$ 76,644			$64.28	$ 2,239,393
0 to 499 MCF/Yr	Transport	$22.00	$23.10	99,910	$ 2,198,021	$ -	$ -	$ -	$ -	$ 109,901			$32.14	$ 3,211,109
500 to 999 MCF/Yr	Transport	$44.00	$46.20	24,578	$ 1,081,426	$ -	$ -	$ -	$ -	$ 54,071			$64.28	$ 1,579,866
Delivery Charge	Sales	$3.9844	$4.1730	7,025,463	$ 27,992,254	$ 19,671	$ (49,788)	$ -	$ (83,603)	$ 1,438,990			$5.7095	$ 40,111,881
	Transport	$3.9844	$4.1864	3,113,845	$ 12,406,803	$ 8,685	$ -	$ -	$ -	$ 620,340			$5.7095	$ 17,778,496
Negotiated		$0.1100	$0.3121	3,601	$ 396	$ 10	$ -	$ -	$ -	$ 717			$0.1100	$ 396
Industrial SGS														
Customer Charge														
0 to 499 MCF/Yr	Sales	$22.00	$23.10	393	$ 8,646	$ -	$ -	$ -	$ -	$ 432			$32.14	$ 12,631
500 to 999 MCF/Yr	Sales	$44.00	$46.20	217	$ 9,548	$ -	$ -	$ -	$ -	$ 477			$64.28	$ 13,949
0 to 499 MCF/Yr	Transport	$22.00	$23.10	419	$ 9,218	$ -	$ -	$ -	$ -	$ 461			$32.14	$ 13,467
500 to 999 MCF/Yr	Transport	$44.00	$46.20	98	$ 4,312	$ -	$ -	$ -	$ -	$ 216			$64.28	$ 6,299
						$ -	$ -	$ -	$ -	$ -				
Delivery Charge	Sales	$3.9844	$4.1730	32,361	$ 128,937	$ 91	$ (229)	$ -	$ (385)	$ 6,628			$5.7095	$ 184,762
	Transport	$3.9844	$4.1864	16,481	$ 65,666	$ 46	$ -	$ -	$ -	$ 3,283			$5.7095	$ 94,098
Negotiated		$0.0936		3,970	$ 371	$ 11	$ -	$ -	$ -	$ 791			$0.0936	$ 371
SGS Total					$ 54,788,815	$ 28,514	$ (50,017)	$ -	$ (83,988)	$ 2,780,470	$ 21,443,151	$ 78,906,944		$ 78,906,713

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-4 - Rate Design

		Current Base Rates	Current Plus Rolled-in Riders	Billing Determinants	Current Base Revenue	Rolled-in Rider Revenue					Revenue Increase	Target Base Revenue	Proposed Rates	Proposed Base Revenue
						STAS	MFC	USR	GPC	DSIC				
Commercial MGS														
Customer Charge														
1,000 to 2,499 MCF/Yr	Sales	$101.00	$106.05	16,193	$ 1,635,467	$ -	$ -	$ -	$ -	$ 81,773			$110.00	$ 1,781,201
2,500 to 24,999 MCF/Yr	Sales	$145.00	$152.25	4,123	$ 597,849	$ -	$ -	$ -	$ -	$ 29,892			$158.00	$ 651,449
1,000 to 2,499 MCF/Yr	Transport	$101.00	$106.05	21,089	$ 2,129,993	$ -	$ -	$ -	$ -	$ 106,500			$110.00	$ 2,319,794
2,500 to 24,999 MCF/Yr	Transport	$145.00	$152.25	16,024	$ 2,323,455	$ -	$ -	$ -	$ -	$ 116,173			$158.00	$ 2,531,765
						$ -	$ -	$ -	$ -	$ -				
Delivery Charge	Sales	$3.6941	$3.8680	3,414,015	$ 12,611,713	$ 8,828	$ (24,194)	$ -	$ (40,627)	$ 649,721			$5.2072	$ 17,777,459
	Transport	$3.6941	$3.8814	11,001,976	$ 40,642,400	$ 28,450	$ -	$ -	$ -	$ 2,032,120			$5.2072	$ 57,289,490
Negotiated	Transport	$0.6192		35,014	$ 21,679	$ 91	$ -	$ -	$ -	$ 6,467			$0.6192	$ 21,679
Industrial MGS														
Customer Charge														
1,000 to 2,499 MCF/Yr	Sales	$101.00	$106.05	265	$ 26,765	$ -	$ -	$ -	$ -	$ 1,338			$110.00	$ 29,150
2,500 to 24,999 MCF/Yr	Sales	$145.00	$152.25	286	$ 41,470	$ -	$ -	$ -	$ -	$ 2,074			$158.00	$ 45,188
1,000 to 2,499 MCF/Yr	Transport	$101.00	$106.05	335	$ 33,835	$ -	$ -	$ -	$ -	$ 1,692			$110.00	$ 36,850
2,500 to 24,999 MCF/Yr	Transport	$145.00	$152.25	1,212	$ 175,740	$ -	$ -	$ -	$ -	$ 8,787			$158.00	$ 191,496
						$ -	$ -	$ -	$ -	$ -				
Delivery Charge	Sales	$3.6941	$3.8680	181,655	$ 671,051	$ 470	$ (1,287)	$ -	$ (2,162)	$ 34,571			$5.2072	$ 945,912
	Transport	$3.6941	$3.8814	1,215,942	$ 4,491,811	$ 3,144	$ -	$ -	$ -	$ 224,591			$5.2072	$ 6,331,653
Negotiated	Transport	$0.2990		94,157	$ 28,157	$ 243	$ -	$ -	$ -	$ 17,391			$0.2990	$ 28,157
MGS Total					$ 65,431,384	$ 41,226	$ (25,482)	$ -	$ (42,788)	$ 3,313,090	$ 21,264,419	$ 89,981,847		$ 89,981,243

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-4 - Rate Design

		Current Base Rates	Current Plus Rolled-in Riders	Billing Determinants	Current Base Revenue	Rolled-in Rider Revenue					Revenue Increase	Target Base Revenue	Proposed Rates	Proposed Base Revenue
						STAS	MFC	USR	GPC	DSIC				
Commercial LGS														
Customer Charge														
25,000 to 49,999 MCF/Yr	Sales	$940.00	$987.00	103	$ 96,820	$ -	$ -	$ -	$ -	$ 4,841			$987.00	$ 101,661
50,000 to 99,999 MCF/Yr	Sales	$1,465.00	$1,538.25	3	$ 4,395	$ -	$ -	$ -	$ -	$ 220			$1,538.00	$ 4,614
100,000 to 199,999 MCF/Yr	Sales	$2,130.00	$2,236.50	-	$ -	$ -	$ -	$ -	$ -	$ -			$2,237.00	$ -
Over 200,000 MCF/Yr	Sales	$5,630.00	$5,911.50	-	$ -	$ -	$ -	$ -	$ -	$ -			$5,912.00	$ -
25,000 to 49,999 MCF/Yr	Transport	$940.00	$987.00	670	$ 629,800	$ -	$ -	$ -	$ -	$ 31,490			$987.00	$ 661,290
50,000 to 99,999 MCF/Yr	Transport	$1,465.00	$1,538.25	384	$ 562,560	$ -	$ -	$ -	$ -	$ 28,128			$1,538.00	$ 590,592
100,000 to 199,999 MCF/Yr	Transport	$2,130.00	$2,236.50	156	$ 332,280	$ -	$ -	$ -	$ -	$ 16,614			$2,237.00	$ 348,972
Over 200,000 MCF/Yr	Transport	$5,630.00	$5,911.50	48	$ 270,240	$ -	$ -	$ -	$ -	$ 13,512			$5,912.00	$ 283,776
Delivery Charge														
25,000 - 49,999 MCF/Yr	Sales	$2.6360	$2.8881	314,695									$2.9451	$ 926,809
50,000 - 99,999 MCF/Yr	Sales	$2.5519	$2.7955	-									$2.8512	$ -
100,000 - 199,999 MCF/Yr	Sales	$2.4335	$2.6652	-									$2.7189	$ -
200,000 to 749,999 MCF/Yr	Sales	$2.1937	$2.4012	-									$2.4509	$ -
750,000 to 1,999,999 MCF/Yr	Sales	$1.9097	$2.0886	-									$2.1336	$ -
Over 2,000,000 MCF/Yr	Sales	$1.4431	$1.5750	-									$1.6123	$ -
Blended Full Tariff	Sales	$2.6360	$2.8581	*314,695*	$ 829,536	$ 581	$ (2,230)	$ -	$ (3,745)	$ 75,289			$2.9451	
25,000 - 49,999 MCF/Yr	Transport	$2.6360	$2.7696	1,945,530									$2.9451	$ 5,729,780
50,000 - 99,999 MCF/Yr	Transport	$2.5519	$2.6813	2,378,579									$2.8512	$ 6,781,805
100,000 - 199,999 MCF/Yr	Transport	$2.4335	$2.5569	1,692,774									$2.7189	$ 4,602,483
200,000 to 749,999 MCF/Yr	Transport	$2.1937	$2.3049	1,513,389									$2.4509	$ 3,709,165
750,000 to 1,999,999 MCF/Yr	Transport	$1.9097	$2.0065	-									$2.1336	$ -
Over 2,000,000 MCF/Yr	Transport	$1.4431	$1.5163	-									$1.6123	$ -
Blended Full Tariff	Transport	$2.4747	$2.7157	*7,530,272*	$ 18,635,391	$ 13,045	$ -	$ -	$ -	$ 1,801,579			$2.7649	
Negotiated	Transport	$2.3379	$2.3396	171,195	$ 400,232	$ 297	$ -	$ -	$ -	$ -			$2.3379	$ 400,232

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-4 - Rate Design

		Current Base Rates	Current Plus Rolled-in Riders	Billing Determinants	Current Base Revenue	Rolled-in Rider Revenue					Revenue Increase	Target Base Revenue	Proposed Rates	Proposed Base Revenue
						STAS	MFC	USR	GPC	DSIC				
Industrial LGS														
Customer Charge														
25,000 to 49,999 MCF/Yr	Sales	$940.00	$987.00	28	$ 26,320	$ -	$ -	$ -	$ -	$ 1,316			$987.00	$ 27,636
50,000 to 99,999 MCF/Yr	Sales	$1,465.00	$1,538.25	-	$ -	$ -	$ -	$ -	$ -	$ -			$1,538.00	$ -
100,000 to 199,999 MCF/Yr	Sales	$2,130.00	$2,236.50	3	$ 6,390	$ -	$ -	$ -	$ -	$ 320			$2,237.00	$ 6,711
Over 200,000 MCF/Yr	Sales	$5,630.00	$5,911.50	12	$ 67,560	$ -	$ -	$ -	$ -	$ 3,378			$5,912.00	$ 70,944
25,000 to 49,999 MCF/Yr	Transport	$940.00	$987.00	353	$ 331,820	$ -	$ -	$ -	$ -	$ 16,591			$987.00	$ 348,411
50,000 to 99,999 MCF/Yr	Transport	$1,465.00	$1,538.25	353	$ 517,145	$ -	$ -	$ -	$ -	$ 25,857			$1,538.00	$ 542,914
100,000 to 199,999 MCF/Yr	Transport	$2,130.00	$2,236.50	278	$ 592,140	$ -	$ -	$ -	$ -	$ 29,607			$2,237.00	$ 621,886
Over 200,000 MCF/Yr	Transport	$5,630.00	$5,911.50	379	$ 2,133,770	$ -	$ -	$ -	$ -	$ 106,689			$5,912.00	$ 2,240,648
Delivery Charge														
25,000 - 49,999 MCF/Yr	Sales	$2.6360	$2.7563	17,128									$2.9451	$ 50,445
50,000 - 99,999 MCF/Yr	Sales	$2.5519	$2.6679	762									$2.8512	$ 2,173
100,000 - 199,999 MCF/Yr	Sales	$2.4335	$2.5435	-									$2.7189	$ -
200,000 to 749,999 MCF/Yr	Sales	$2.1937	$2.2915	-									$2.4509	$ -
750,000 to 1,999,999 MCF/Yr	Sales	$1.9097	$1.9931	-									$2.1336	$ -
Over 2,000,000 MCF/Yr	Sales	$1.4431	$1.5029	-									$1.6123	$ -
Blended Full Tariff	Sales	$2.6172	$2.8393	17,891	$ 46,823	$ 33	$ (127)	$ -	$ (213)	$ 4,280			$2.9241	
25,000 - 49,999 MCF/Yr	Transport	$2.6360	$2.7696	1,277,708									$2.9451	$ 3,762,977
50,000 - 99,999 MCF/Yr	Transport	$2.5519	$2.6813	1,466,279									$2.8512	$ 4,180,654
100,000 - 199,999 MCF/Yr	Transport	$2.4335	$2.5569	3,336,684									$2.7189	$ 9,072,110
200,000 to 749,999 MCF/Yr	Transport	$2.1937	$2.3049	5,950,590									$2.4509	$ 14,584,302
750,000 to 1,999,999 MCF/Yr	Transport	$1.9097	$2.0065	836,183									$2.1336	$ 1,784,080
Over 2,000,000 MCF/Yr	Transport	$1.4431	$1.5163	-									$1.6123	$ -
Blended Full Tariff		$2.3846	$2.6252	12,867,444	$ 30,684,151	$ 16,622	$ -	$ -	$ -	$ 3,078,471			$2.6643	
Negotiated		$0.2634	$0.2647	5,696,556	$ 1,500,745	$ 7,359	$ -	$ -	$ -	$ -			$0.2634	$ 1,500,745
LGS Total					$ 57,668,118	$ 37,936	$ (2,357)	$ -	$ (3,958)	$ 5,238,182	$ -	$ 62,937,921		$ 62,937,814

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-4 - Rate Design

		Current Base Rates	Current Plus Rolled-in Riders	Billing Determinants	Current Base Revenue	Rolled-in Rider Revenue					Revenue Increase	Target Base Revenue	Proposed Rates	Proposed Base Revenue
						STAS	MFC	USR	GPC	DSIC				
Mainline Service (MLS)														
Customer Charge														
Over 500,000 MCF/Yr	Sales	$5,630.00	$5,630.00		$ -	$ -	$ -	$ -	$ -	$ -			$5,912.00	$ -
Over 500,000 MCF/Yr	Transport	$5,630.00	$5,630.00	96	$ 540,480	$ -	$ -	$ -	$ -	$ -			$5,912.00	$ 567,552
Delivery Charge														
PNG transmission line	Sales	$0.7430	$0.7245		$ -	$ -	$ -	$ -	$ -	$ -			$0.7470	$ -
Interstate pipeline	Sales	$0.4422	$0.4235		$ -	$ -	$ -	$ -	$ -	$ -			$0.4446	$ -
PNG transmission line	Transport	$0.7430	$0.7435	-	$ -	$ -	$ -	$ -	$ -	$ -			$0.7470	$ -
Interstate pipeline	Transport	$0.4422	$0.4349	1,694,527	$ 749,320	$ 2,189	$ -	$ -	$ -	$ -			$0.4446	$ 753,387
Negotiated		$0.2634	$0.2647	22,354,141	$ 5,889,149	$ 28,877	$ -	$ -	$ -	$ -			$0.2634	$ 5,889,149
MLS Total					$ 7,178,949	$ 31,066	$ -	$ -	$ -	$ -	$ -	$ 7,210,016		$ 7,210,088
SYSTEM TOTAL					$ 616,555,782	$ 346,045	$ 1,001,765	$ (280,390)	$ (730,216)	$ 36,632,493	$ 160,871,017	$ 814,396,494		$ 814,393,212
Difference due to rounding														*$ (3,282)*

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Residential Service

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
1	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
2	Customer Charge	12	$ 16.80	$ 201.60	$26.00	$ 312.00	$ 16.80	$ 201.60	$26.00	$ 312.00
3	Riders:									
4	Supplier Choice	12	$ 0.0036	$ 0.04	$0.0036	$ 0.04	$ 0.0036	$ 0.04	$0.0036	$ 0.04
5	DSIC	12	$ 0.8400	$ 10.08	$0.0000	$ -	$ 0.8400	$ 10.08	$0.0000	$ -
6	TRS	12	$ (0.1033)	$ (1.24)	$ (0.1033)	$ (1.24)	$ (0.1033)	$ (1.24)	$ (0.1033)	$ (1.24)
7	Total Monthly Charge		$ 17.54	$ 210.48	$ 25.90	$ 310.80	$ 17.54	$ 210.48	$ 25.90	$ 310.80
8	Volumetric Charges	Usage (Mcf)								
9	Delivery Charge per Mcf	86	$ 5.3537	$ 460.42	$ 6.6359	$ 570.69	$ 5.3537	$ 460.42	$ 6.6359	$ 570.69
10	Riders:									
11	STAS	86	$ 0.0037	$ 0.32	$ -	$ -	$ 0.0037	$ 0.32	$ -	$ -
12	MFC	86	$ 0.1699	$ 14.61	$ 0.1490	$ 12.82	$ 0.0410	$ 3.53	$ 0.0360	$ 3.09
13	USR	86	$ -	$ -	$ 0.0054	$ 0.46	$ -	$ -	$ 0.0054	$ 0.46
14	GPC	86	$ 0.0865	$ 7.44	$ 0.0984	$ 8.46	$ -	$ -	$ -	$ -
15	DSIC	86	$ 0.3353	$ 28.83	$ -	$ -	$ 0.3245	$ 27.91	$ -	$ -
16	TRS	86	$ (0.0329)	$ (2.83)	$ (0.0329)	$ (2.83)	$ (0.0329)	$ (2.83)	$ (0.0329)	$ (2.83)
17	Total Delivery Rate per Mcf		$ 5.9162	$ 508.79	$ 6.8558	$ 589.60	$ 5.6900	$ 489.34	$ 6.6444	$ 571.42
18	Annual Bill without Gas Cost			$ 719.28		$ 900.41		$ 699.82		$ 882.22
19	Average Monthly Bill without Gas Cost			$ 59.94		$ 75.03		$ 58.32		$ 73.52
20	Gas Cost 1/	86	$ 7.7219	$ 664.08	$ 7.7219	$ 664.08	$ 1.8641	$ 160.31	$ 1.8641	$ 160.31
21	Total Rate per Mcf with Gas Cost		$ 13.6381		$ 14.5777		$ 7.5541		$ 8.5085	
22	Annual Bill with Gas Cost			$ 1,383.36		$ 1,564.49		$ 860.14		$ 1,042.53
23	Average Monthly Bill with Gas Cost			$ 115.28		$ 130.37		$ 71.68		$ 86.88
24	Change in Annual Bill					$ 181.13				$ 182.40
25	Change in Monthly Bill					$ 15.09				$ 15.20
26	Percent Change in Bill without Gas Cost					25.2%				26.1%
27	Percent Change in Bill with Gas Cost					13.1%				21.2%

1/ gas cost capacity for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Small General Service - 0 to 499 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
28	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
29	Customer Charge	12	$ 22.00	$ 264.00	$32.14	$ 385.68	$ 22.00	$ 264.00	$32.14	$ 385.68
30	Riders:									
31	Supplier Choice	12	$ 0.0036	$ 0.04	$0.0036	$ 0.04	$ 0.0036	$ 0.04	$0.0036	$ 0.04
32	DSIC	12	$ 1.1000	$ 13.20	$0.0000	$ -	$ 1.1000	$ 13.20	$0.0000	$ -
33	TRS	12	$ (0.1352)	$ (1.62)	$ (0.1352)	$ (1.62)	$ (0.1352)	$ (1.62)	$ (0.1352)	$ (1.62)
34	Total Monthly Charge		$ 22.97	$ 275.62	$ 32.01	$ 384.10	$ 22.97	$ 275.62	$ 32.01	$ 384.10
35	Volumetric Charges	Usage (Mcf)								
36	Delivery Charge per Mcf	250	$ 3.9844	$ 996.10	$ 5.7095	$ 1,427.38	$ 3.9844	$ 996.10	$ 5.7095	$ 1,427.38
37	Riders:									
38	STAS	250	$ 0.0028	$ 0.70	$ -	$ -	$ 0.0028	$ 0.70	$ -	$ -
39	MFC	250	$ 0.0256	$ 6.40	$ 0.0327	$ 8.17	$ -	$ -	$ -	$ -
40	GPC	250	$ 0.0865	$ 21.63	$ 0.0984	$ 24.60	$ -	$ -	$ -	$ -
41	DSIC	250	$ 0.2048	$ 51.21	$ -	$ -	$ 0.1992	$ 49.81	$ -	$ -
42	TRS	250	$ (0.0245)	$ (6.12)	$ (0.0245)	$ (6.12)	$ (0.0245)	$ (6.12)	$ (0.0245)	$ (6.12)
43	Total Delivery Rate per Mcf		$ 4.2796	$ 1,069.91	$ 5.8161	$ 1,454.02	$ 4.1619	$ 1,040.48	$ 5.6850	$ 1,421.25
44	Annual Bill without Gas Cost			$ 1,345.53		$ 1,838.13		$ 1,316.10		$ 1,805.35
45	Average Monthly Bill without Gas Cost			$ 112.13		$ 153.18		$ 109.68		$ 150.45
46	Gas Cost 1/	250	$ 7.7219	$ 1,930.47	$ 7.7219	$ 1,930.47	$ 0.8300	$ 207.50	$ 0.8300	$ 207.50
47	Total Rate per Mcf with Gas Cost		$ 12.0015		$ 13.5380		$ 4.9919		$ 6.5150	
48	Annual Bill with Gas Cost			$ 3,276.00		$ 3,768.60		$ 1,523.60		$ 2,012.85
49	Average Monthly Bill with Gas Cost			$ 273.00		$ 314.05		$ 126.97		$ 167.74
50	Change in Annual Bill					$ 492.60				$ 489.25
51	Change in Monthly Bill					$ 41.05				$ 40.77
52	Percent Change in Bill without Gas Cost					36.6%				37.2%
53	Percent Change in Bill with Gas Cost					15.0%				32.1%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Small General Service - 500 to 999 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
54	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
55	Customer Charge	12	$ 44.00	$ 528.00	$64.28	$ 771.36	$ 44.00	$ 528.00	$64.28	$ 771.36
56	Riders:									
57	Supplier Choice	12	$ 0.0036	$ 0.04	$0.0036	$ 0.04	$ 0.0036	$ 0.04	$0.0036	$ 0.04
58	DSIC	12	$ 2.2000	$ 26.40	$0.0000	$ -	$ 2.2000	$ 26.40	$0.0000	$ -
59	TRS	12	$ (0.2704)	$ (3.25)	$ (0.2704)	$ (3.25)	$ (0.2704)	$ (3.25)	$ (0.2704)	$ (3.25)
60	Total Monthly Charge		$ 45.93	$ 551.20	$ 64.01	$ 768.16	$ 45.93	$ 551.20	$ 64.01	$ 768.16
61	Volumetric Charges	Usage (Mcf)								
62	Delivery Charge per Mcf	750	$ 3.9844	$ 2,988.30	$ 5.7095	$ 4,282.13	$ 3.9844	$ 2,988.30	$ 5.7095	$ 4,282.13
63	Riders:									
64	STAS	750	$ 0.0028	$ 2.10	$ -	$ -	$ 0.0028	$ 2.09	$ -	$ -
65	MFC	750	$ 0.0256	$ 19.20	$ 0.0327	$ 24.52	$ -	$ -	$ -	$ -
66	GPC	750	$ 0.0865	$ 64.88	$ 0.0984	$ 73.80	$ -	$ -	$ -	$ -
67	DSIC	750	$ 0.2048	$ 153.62	$ -	$ -	$ 0.1992	$ 149.42	$ -	$ -
68	TRS	750	$ (0.0245)	$ (18.37)	$ (0.0245)	$ (18.37)	$ (0.0245)	$ (18.37)	$ (0.0245)	$ (18.37)
69	Total Delivery Rate per Mcf		$ 4.2796	$ 3,209.73	$ 5.8161	$ 4,362.07	$ 4.1619	$ 3,121.44	$ 5.6850	$ 4,263.76
70	Annual Bill without Gas Cost			$ 3,760.93		$ 5,130.23		$ 3,672.64		$ 5,031.92
71	Average Monthly Bill without Gas Cost			$ 313.41		$ 427.52		$ 306.05		$ 419.33
72	Gas Cost 1/	750	$ 7.7219	$ 5,791.42	$ 7.7219	$ 5,791.42	$ 0.8300	$ 622.50	$ 0.8300	$ 622.50
73	Total Rate per Mcf with Gas Cost		$ 12.0015		$ 13.5380		$ 4.9919		$ 6.5150	
74	Annual Bill with Gas Cost			$ 9,552.34		$ 10,921.65		$ 4,295.14		$ 5,654.42
75	Average Monthly Bill with Gas Cost			$ 796.03		$ 910.14		$ 357.93		$ 471.20
76	Change in Annual Bill					$ 1,369.31				$ 1,359.28
77	Change in Monthly Bill					$ 114.11				$ 113.27
78	Percent Change in Bill without Gas Cost					36.4%				37.0%
79	Percent Change in Bill with Gas Cost					14.3%				31.6%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Medium General Service - 1,000 to 2,499 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
80	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
81	Customer Charge	12	$ 101.00	$ 1,212.00	$110.00	$ 1,320.00	$ 101.00	$ 1,212.00	$110.00	$ 1,320.00
82	Riders:									
83	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
84	DSIC	12	$ 5.0500	$ 60.60	$0.0000	$ -	$ 5.0500	$ 60.60	$0.0000	$ -
85	TRS	12	$ (0.6207)	$ (7.45)	$ (0.6207)	$ (7.45)	$ (0.6207)	$ (7.45)	$ (0.6207)	$ (7.45)
86	Total Monthly Charge		$ 105.43	$ 1,265.15	$ 109.38	$ 1,312.55	$ 105.43	$ 1,265.15	$ 109.38	$ 1,312.55
87	Volumetric Charges	Usage (Mcf)								
88	Delivery Charge per Mcf	1,750	$ 3.6941	$ 6,464.68	$ 5.2072	$ 9,112.60	$ 3.6941	$ 6,464.68	$ 5.2072	$ 9,112.60
89	Riders:									
90	STAS	1,750	$ 0.0026	$ 4.53	$ -	$ -	$ 0.0026	$ 4.53	$ -	$ -
91	MFC	1,750	$ 0.0256	$ 44.80	$ 0.0327	$ 57.20	$ -	$ -	$ -	$ -
92	GPC	1,750	$ 0.0865	$ 151.38	$ 0.0984	$ 172.20	$ -	$ -	$ -	$ -
93	DSIC	1,750	$ 0.1903	$ 333.04	$ -	$ -	$ 0.1847	$ 323.23	$ -	$ -
94	TRS	1,750	$ (0.0227)	$ (39.73)	$ (0.0227)	$ (39.73)	$ (0.0227)	$ (39.73)	$ (0.0227)	$ (39.73)
95	Total Delivery Rate per Mcf		$ 3.9764	$ 6,958.69	$ 5.3156	$ 9,302.27	$ 3.8587	$ 6,752.70	$ 5.1845	$ 9,072.87
96	Annual Bill without Gas Cost			$ 8,223.84		$ 10,614.82		$ 8,017.85		$ 10,385.42
97	Average Monthly Bill without Gas Cost			$ 685.32		$ 884.57		$ 668.15		$ 865.45
98	Gas Cost 1/	1,750	$ 7.7219	$ 13,513.31	$ 7.7219	$ 13,513.31	$ 0.8300	$ 1,452.50	$ 0.8300	$ 1,452.50
99	Total Rate per Mcf with Gas Cost		$ 11.6983		$ 13.0375		$ 4.6887		$ 6.0145	
100	Annual Bill with Gas Cost			$ 21,737.14		$ 24,128.13		$ 9,470.35		$ 11,837.92
101	Average Monthly Bill with Gas Cost			$ 1,811.43		$ 2,010.68		$ 789.20		$ 986.49
102	Change in Annual Bill					$ 2,390.98				$ 2,367.57
103	Change in Monthly Bill					$ 199.25				$ 197.30
104	Percent Change in Bill without Gas Cost					29.1%				29.5%
105	Percent Change in Bill with Gas Cost					11.0%				25.0%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Medium General Service - 2,500 to 24,999 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
106	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
107	Customer Charge	12	$ 145.00	$ 1,740.00	$158.00	$ 1,896.00	$ 145.00	$ 1,740.00	$158.00	$ 1,896.00
108	Riders:									
109	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
110	DSIC	12	$ 7.2500	$ 87.00	$0.0000	$ -	$ 7.2500	$ 87.00	$0.0000	$ -
111	TRS	12	$ (0.8912)	$ (10.69)	$ (0.8912)	$ (10.69)	$ (0.8912)	$ (10.69)	$ (0.8912)	$ (10.69)
112	Total Monthly Charge		$ 151.36	$ 1,816.31	$ 157.11	$ 1,885.31	$ 151.36	$ 1,816.31	$ 157.11	$ 1,885.31
113	Volumetric Charges	Usage (Mcf)								
114	Delivery Charge per Mcf	13,750	$ 3.6941	$ 50,793.88	$ 5.2072	$ 71,599.00	$ 3.6941	$ 50,793.88	$ 5.2072	$ 71,599.00
115	Riders:									
116	STAS	13,750	$ 0.0026	$ 35.56	$ -	$ -	$ 0.0026	$ 35.56	$ -	$ -
117	MFC	13,750	$ 0.0256	$ 352.00	$ 0.0327	$ 449.44	$ -	$ -	$ -	$ -
118	GPC	13,750	$ 0.0865	$ 1,189.38	$ 0.0984	$ 1,353.00	$ -	$ -	$ -	$ -
119	DSIC	13,750	$ 0.1903	$ 2,616.76	$ -	$ -	$ 0.1847	$ 2,539.69	$ -	$ -
120	TRS	13,750	$ (0.0227)	$ (312.18)	$ (0.0227)	$ (312.18)	$ (0.0227)	$ (312.18)	$ (0.0227)	$ (312.18)
121	Total Delivery Rate per Mcf		$ 3.9764	$ 54,675.39	$ 5.3156	$ 73,089.26	$ 3.8587	$ 53,056.95	$ 5.1845	$ 71,286.82
122	Annual Bill without Gas Cost			$ 56,491.70		$ 74,974.57		$ 54,873.25		$ 73,172.13
123	Average Monthly Bill without Gas Cost			$ 4,707.64		$ 6,247.88		$ 4,572.77		$ 6,097.68
124	Gas Cost 1/	13,750	$ 7.7219	$ 106,175.98	$ 7.7219	$ 106,175.98	$ 0.8300	$ 11,412.50	$ 0.8300	$ 11,412.50
125	Total Rate per Mcf with Gas Cost		$ 11.6983		$ 13.0375		$ 4.6887		$ 6.0145	
126	Annual Bill with Gas Cost			$ 162,667.67		$ 181,150.55		$ 66,285.75		$ 84,584.63
127	Average Monthly Bill with Gas Cost			$ 13,555.64		$ 15,095.88		$ 5,523.81		$ 7,048.72
128	Change in Annual Bill					$ 18,482.87				$ 18,298.88
129	Change in Monthly Bill					$ 1,540.24				$ 1,524.91
130	Percent Change in Bill without Gas Cost					32.7%				33.3%
131	Percent Change in Bill with Gas Cost					11.4%				27.6%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Large General Service - 25,000 - 49,999 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
132	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
133	Customer Charge	12	$ 940.00	$ 11,280.00	$987.00	$ 11,844.00	$ 940.00	$ 11,280.00	$987.00	$ 11,844.00
134	Riders:									
135	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
136	DSIC	12	$ 47.0000	$ 564.00	$0.0000	$ -	$ 47.0000	$ 564.00	$0.0000	$ -
137	TRS	12	$ (5.7772)	$ (69.33)	$ (5.7772)	$ (69.33)	$ (5.7772)	$ (69.33)	$ (5.7772)	$ (69.33)
138	Total Monthly Charge		$ 981.22	$ 11,774.67	$ 981.22	$ 11,774.67	$ 981.22	$ 11,774.67	$ 981.22	$ 11,774.67
139	Volumetric Charges	Usage (Mcf)								
140	Delivery Charge per Mcf	37,500	$ 2.6360	$ 98,850.00	$ 2.9451	$ 110,441.25	$ 2.6360	$ 98,850.00	$ 2.9451	$ 110,441.25
141	Riders:									
142	STAS	37,500	$ 0.0018	$ 69.20	$ -	$ -	$ 0.0018	$ 69.20	$ -	$ -
143	MFC	37,500	$ 0.0256	$ 960.00	$ 0.0327	$ 1,225.75	$ -	$ -	$ -	$ -
144	GPC	37,500	$ 0.0865	$ 3,243.75	$ 0.0984	$ 3,690.00	$ -	$ -	$ -	$ -
145	DSIC	37,500	$ 0.1374	$ 5,152.69	$ -	$ -	$ 0.1318	$ 4,942.50	$ -	$ -
146	TRS	37,500	$ (0.0162)	$ (607.53)	$ (0.0162)	$ (607.53)	$ (0.0162)	$ (607.53)	$ (0.0162)	$ (607.53)
147	Total Delivery Rate per Mcf		$ 2.8711	$ 107,668.10	$ 3.0600	$ 114,749.47	$ 2.7534	$ 103,254.16	$ 2.9289	$ 109,833.72
148	Annual Bill without Gas Cost			$ 119,442.77		$ 126,524.14		$ 115,028.84		$ 121,608.39
149	Average Monthly Bill without Gas Cost			$ 9,953.56		$ 10,543.68		$ 9,585.74		$ 10,134.03
150	Gas Cost 1/	37,500	$ 7.7219	$ 289,570.84	$ 7.7219	$ 289,570.84	$ 0.1740	$ 6,525.00	$ 0.1740	$ 6,525.00
151	Total Rate per Mcf with Gas Cost		$ 10.5930		$ 10.7819		$ 2.9274		$ 3.1029	
152	Annual Bill with Gas Cost			$ 409,013.62		$ 416,094.99		$ 121,553.84		$ 128,133.39
153	Average Monthly Bill with Gas Cost			$ 34,084.47		$ 34,674.58		$ 10,129.49		$ 10,677.78
154	Change in Annual Bill					$ 7,081.37				$ 6,579.55
155	Change in Monthly Bill					$ 590.11				$ 548.30
156	Percent Change in Bill without Gas Cost					5.9%				5.7%
157	Percent Change in Bill with Gas Cost					1.7%				5.4%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Large General Service - 50,000 - 99,999 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
158	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
159	Customer Charge	12	$ 1,465.00	$ 17,580.00	$1,538.00	$ 18,456.00	$ 1,465.00	$ 17,580.00	$1,538.00	$ 18,456.00
160	Riders:									
161	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
162	DSIC	12	$ 73.2500	$ 879.00	$0.0000	$ -	$ 73.2500	$ 879.00	$0.0000	$ -
163	TRS	12	$ (9.0039)	$ (108.05)	$ (9.0039)	$ (108.05)	$ (9.0039)	$ (108.05)	$ (9.0039)	$ (108.05)
164	Total Monthly Charge		$ 1,529.25	$ 18,350.95	$ 1,529.00	$ 18,347.95	$ 1,529.25	$ 18,350.95	$ 1,529.00	$ 18,347.95
165	Volumetric Charges	Usage (Mcf)								
166	Delivery Charge per Mcf	75,000	$ 2.5519	$ 191,392.50	$ 2.8512	$ 213,840.00	$ 2.5519	$ 191,392.50	$ 2.8512	$ 213,840.00
167	Riders:									
168	STAS	75,000	$ 0.0018	$ 133.97	$ -	$ -	$ 0.0018	$ 133.97	$ -	$ -
169	MFC	75,000	$ 0.0256	$ 1,920.00	$ 0.0327	$ 2,451.51	$ -	$ -	$ -	$ -
170	GPC	75,000	$ 0.0865	$ 6,487.50	$ 0.0984	$ 7,380.00	$ -	$ -	$ -	$ -
171	DSIC	75,000	$ 0.1332	$ 9,990.00	$ -	$ -	$ 0.1276	$ 9,569.63	$ -	$ -
172	TRS	75,000	$ (0.0157)	$ (1,176.30)	$ (0.0157)	$ (1,176.30)	$ (0.0157)	$ (1,176.30)	$ (0.0157)	$ (1,176.30)
173	Total Delivery Rate per Mcf		$ 2.7833	$ 208,747.68	$ 2.9666	$ 222,495.21	$ 2.6656	$ 199,919.80	$ 2.8355	$ 212,663.70
174	Annual Bill without Gas Cost			$ 227,098.63		$ 240,843.16		$ 218,270.75		$ 231,011.66
175	Average Monthly Bill without Gas Cost			$ 18,924.89		$ 20,070.26		$ 18,189.23		$ 19,250.97
176	Gas Cost 1/	75,000	$ 7.7219	$ 579,141.68	$ 7.7219	$ 579,141.68	$ 0.1740	$ 13,050.00	$ 0.1740	$ 13,050.00
177	Total Rate per Mcf with Gas Cost		$ 10.5052		$ 10.6885		$ 2.8396		$ 3.0095	
178	Annual Bill with Gas Cost			$ 806,240.31		$ 819,984.85		$ 231,320.75		$ 244,061.66
179	Average Monthly Bill with Gas Cost			$ 67,186.69		$ 68,332.07		$ 19,276.73		$ 20,338.47
180	Change in Annual Bill					$ 13,744.53				$ 12,740.90
181	Change in Monthly Bill					$ 1,145.38				$ 1,061.74
182	Percent Change in Bill without Gas Cost					6.1%				5.8%
183	Percent Change in Bill with Gas Cost					1.7%				5.5%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Large General Service - 100,000 - 199,999 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
184	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
185	Customer Charge	12	$ 2,130.00	$ 25,560.00	$2,237.00	$ 26,844.00	$ 2,130.00	$ 25,560.00	$2,237.00	$ 26,844.00
186	Riders:									
187	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
188	DSIC	12	$ 106.5000	$ 1,278.00	$0.0000	$ -	$ 106.5000	$ 1,278.00	$0.0000	$ -
189	TRS	12	$ (13.0910)	$ (157.09)	$ (13.0910)	$ (157.09)	$ (13.0910)	$ (157.09)	$ (13.0910)	$ (157.09)
190	Total Monthly Charge		$ 2,223.41	$ 26,680.91	$ 2,223.91	$ 26,686.91	$ 2,223.41	$ 26,680.91	$ 2,223.91	$ 26,686.91
191	Volumetric Charges	Usage (Mcf)								
192	Delivery Charge per Mcf	150,000	$ 2.4335	$ 365,025.00	$ 2.7189	$ 407,835.00	$ 2.4335	$ 365,025.00	$ 2.7189	$ 407,835.00
193	Riders:									
194	STAS	150,000	$ 0.0017	$ 255.52	$ -	$ -	$ 0.0017	$ 255.52	$ -	$ -
195	MFC	150,000	$ 0.0256	$ 3,840.00	$ 0.0327	$ 4,903.01	$ -	$ -	$ -	$ -
196	GPC	150,000	$ 0.0865	$ 12,975.00	$ 0.0984	$ 14,760.00	$ -	$ -	$ -	$ -
197	DSIC	150,000	$ 0.1273	$ 19,092.00	$ -	$ -	$ 0.1217	$ 18,251.25	$ -	$ -
198	TRS	150,000	$ (0.0150)	$ (2,243.44)	$ (0.0150)	$ (2,243.44)	$ (0.0150)	$ (2,243.44)	$ (0.0150)	$ (2,243.44)
199	Total Delivery Rate per Mcf		$ 2.6596	$ 398,944.07	$ 2.8350	$ 425,254.57	$ 2.5419	$ 381,288.32	$ 2.7039	$ 405,591.56
200	Annual Bill without Gas Cost			$ 425,624.98		$ 451,941.48		$ 407,969.23		$ 432,278.46
201	Average Monthly Bill without Gas Cost			$ 35,468.75		$ 37,661.79		$ 33,997.44		$ 36,023.21
202	Gas Cost 1/	150,000	$ 7.7219	$ 1,158,283.37	$ 7.7219	$ 1,158,283.37	$ 0.1740	$ 26,100.00	$ 0.1740	$ 26,100.00
203	Total Rate per Mcf with Gas Cost		$ 10.3815		$ 10.5569		$ 2.7159		$ 2.8779	
204	Annual Bill with Gas Cost			$ 1,583,908.35		$ 1,610,224.85		$ 434,069.23		$ 458,378.46
205	Average Monthly Bill with Gas Cost			$ 131,992.36		$ 134,185.40		$ 36,172.44		$ 38,198.21
206	Change in Annual Bill					$ 26,316.50				$ 24,309.23
207	Change in Monthly Bill					$ 2,193.04				$ 2,025.77
208	Percent Change in Bill without Gas Cost					6.2%				6.0%
209	Percent Change in Bill with Gas Cost					1.7%				5.6%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Large General Service - 200,000 to 749,999 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
210	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
211	Customer Charge	12	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00
212	Riders:									
213	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
214	DSIC	12	$ 281.5000	$ 3,378.00	$0.0000	$ -	$ 281.5000	$ 3,378.00	$0.0000	$ -
215	TRS	12	$ (34.6020)	$ (415.22)	-$34.6020	$ (415.22)	$ (34.6020)	$ (415.22)	-$34.6020	$ (415.22)
216	Total Monthly Charge		$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78	$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78
217	Volumetric Charges	Usage (Mcf)								
218	Delivery Charge per Mcf	475,000	$ 2.1937	$ 1,042,007.50	$ 2.4509	$ 1,164,177.50	$ 2.1937	$ 1,042,007.50	$ 2.4509	$ 1,164,177.50
219	Riders:									
220	STAS	475,000	$ 0.0015	$ 729.41	$ -	$ -	$ 0.0015	$ 729.41	$ -	$ -
221	MFC	475,000	$ 0.0256	$ 12,160.00	$ 0.0327	$ 15,526.21	$ -	$ -	$ -	$ -
222	GPC	475,000	$ 0.0865	$ 41,087.50	$ 0.0984	$ 46,740.00	$ -	$ -	$ -	$ -
223	DSIC	475,000	$ 0.1153	$ 54,762.75	$ -	$ -	$ 0.1097	$ 52,100.38	$ -	$ -
224	TRS	475,000	$ (0.0135)	$ (6,404.18)	$ (0.0135)	$ (6,404.18)	$ (0.0135)	$ (6,404.18)	$ (0.0135)	$ (6,404.18)
225	Total Delivery Rate per Mcf		$ 2.4091	$ 1,144,342.98	$ 2.5685	$ 1,220,039.53	$ 2.2914	$ 1,088,433.10	$ 2.4374	$ 1,157,773.32
226	Annual Bill without Gas Cost			$ 1,214,865.75		$ 1,290,568.31		$ 1,158,955.88		$ 1,228,302.10
227	Average Monthly Bill without Gas Cost			$ 101,238.81		$ 107,547.36		$ 96,579.66		$ 102,358.51
228	Gas Cost 1/	475,000	$ 7.7219	$ 3,667,897.33	$ 7.7219	$ 3,667,897.33	$ 0.1740	$ 82,650.00	$ 0.1740	$ 82,650.00
229	Total Rate per Mcf with Gas Cost		$ 10.1310		$ 10.2904		$ 2.4654		$ 2.6114	
230	Annual Bill with Gas Cost			$ 4,882,763.09		$ 4,958,465.64		$ 1,241,605.88		$ 1,310,952.10
231	Average Monthly Bill with Gas Cost			$ 406,896.92		$ 413,205.47		$ 103,467.16		$ 109,246.01
232	Change in Annual Bill					$ 75,702.55				$ 69,346.22
233	Change in Monthly Bill					$ 6,308.55				$ 5,778.85
234	Percent Change in Bill without Gas Cost					6.2%				6.0%
235	Percent Change in Bill with Gas Cost					1.6%				5.6%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Large General Service - 750,000 to 1,999,999 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
236	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
237	Customer Charge	12	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00
238	Riders:									
239	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
240	DSIC	12	$ 281.5000	$ 3,378.00	$0.0000	$ -	$ 281.5000	$ 3,378.00	$0.0000	$ -
241	TRS	12	$ (34.6020)	$ (415.22)	-$34.6020	$ (415.22)	$ (34.6020)	$ (415.22)	-$34.6020	$ (415.22)
242	Total Monthly Charge		$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78	$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78
243	Volumetric Charges	Usage (Mcf)								
244	Delivery Charge per Mcf	1,375,000	$ 1.9097	$ 2,625,837.50	$ 2.1336	$ 2,933,700.00	$ 1.9097	$ 2,625,837.50	$ 2.1336	$ 2,933,700.00
245	Riders:									
246	STAS	1,375,000	$ 0.0013	$ 1,838.09	$ -	$ -	$ 0.0013	$ 1,838.09	$ -	$ -
247	MFC	1,375,000	$ 0.0256	$ 35,200.00	$ 0.0327	$ 44,944.29	$ -	$ -	$ -	$ -
248	GPC	1,375,000	$ 0.0865	$ 118,937.50	$ 0.0984	$ 135,300.00	$ -	$ -	$ -	$ -
249	DSIC	1,375,000	$ 0.1011	$ 138,998.75	$ -	$ -	$ 0.0955	$ 131,291.88	$ -	$ -
250	TRS	1,375,000	$ (0.0117)	$ (16,138.40)	$ (0.0117)	$ (16,138.40)	$ (0.0117)	$ (16,138.40)	$ (0.0117)	$ (16,138.40)
251	Total Delivery Rate per Mcf		$ 2.1125	$ 2,904,673.44	$ 2.2529	$ 3,097,805.89	$ 1.9948	$ 2,742,829.06	$ 2.1219	$ 2,917,561.60
252	Annual Bill without Gas Cost			$ 2,975,196.22		$ 3,168,334.67		$ 2,813,351.84		$ 2,988,090.38
253	Average Monthly Bill without Gas Cost			$ 247,933.02		$ 264,027.89		$ 234,445.99		$ 249,007.53
254	Gas Cost 1/	1,375,000	$ 7.7219	$ 10,617,597.55	$ 7.7219	$ 10,617,597.55	$ 0.1740	$ 239,250.00	$ 0.1740	$ 239,250.00
255	Total Rate per Mcf with Gas Cost		$ 9.8344		$ 9.9748		$ 2.1688		$ 2.2959	
256	Annual Bill with Gas Cost			$ 13,592,793.76		$ 13,785,932.22		$ 3,052,601.84		$ 3,227,340.38
257	Average Monthly Bill with Gas Cost			$ 1,132,732.81		$ 1,148,827.68		$ 254,383.49		$ 268,945.03
258	Change in Annual Bill					$ 193,138.45				$ 174,738.54
259	Change in Monthly Bill					$ 16,094.87				$ 14,561.54
260	Percent Change in Bill without Gas Cost					6.5%				6.2%
261	Percent Change in Bill with Gas Cost					1.4%				5.7%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Large General Service - Over 2,000,000 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
262	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
263	Customer Charge	12	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00
264	Riders:									
265	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
266	DSIC	12	$ 281.5000	$ 3,378.00	$0.0000	$ -	$ 281.5000	$ 3,378.00	$0.0000	$ -
267	TRS	12	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)
268	Total Monthly Charge		$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78	$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78
269	Volumetric Charges	Usage (Mcf)								
270	Delivery Charge per Mcf	2,100,000	$ 1.4431	$ 3,030,510.00	$ 1.6123	$ 3,385,830.00	$ 1.4431	$ 3,030,510.00	$ 1.6123	$ 3,385,830.00
271	Riders:									
272	STAS	2,100,000	$ 0.0010	$ 2,121.36	$ -	$ -	$ 0.0010	$ 2,121.36	$ -	$ -
273	MFC	2,100,000	$ 0.0256	$ 53,760.00	$ 0.0327	$ 68,642.19	$ -	$ -	$ -	$ -
274	GPC	2,100,000	$ 0.0865	$ 181,650.00	$ 0.0984	$ 206,640.00	$ -	$ -	$ -	$ -
275	DSIC	2,100,000	$ 0.0778	$ 163,296.00	$ -	$ -	$ 0.0722	$ 151,525.50	$ -	$ -
276	TRS	2,100,000	$ (0.0089)	$ (18,625.51)	$ (0.0089)	$ (18,625.51)	$ (0.0089)	$ (18,625.51)	$ (0.0089)	$ (18,625.51)
277	Total Delivery Rate per Mcf		$ 1.6251	$ 3,412,711.84	$ 1.7345	$ 3,642,486.67	$ 1.5074	$ 3,165,531.34	$ 1.6034	$ 3,367,204.49
278	Annual Bill without Gas Cost			$ 3,483,234.62		$ 3,713,015.45		$ 3,236,054.12		$ 3,437,733.26
279	Average Monthly Bill without Gas Cost			$ 290,269.55		$ 309,417.95		$ 269,671.18		$ 286,477.77
280	Gas Cost 1/	2,100,000	$ 7.7219	$ 16,215,967.16	$ 7.7219	$ 16,215,967.16	$ 0.1740	$ 365,400.00	$ 0.1740	$ 365,400.00
281	Total Rate per Mcf with Gas Cost		$ 9.3470		$ 9.4564		$ 1.6814		$ 1.7774	
282	Annual Bill with Gas Cost			$ 19,699,201.78		$ 19,928,982.61		$ 3,601,454.12		$ 3,803,133.26
283	Average Monthly Bill with Gas Cost			$ 1,641,600.15		$ 1,660,748.55		$ 300,121.18		$ 316,927.77
284	Change in Annual Bill					$ 229,780.83				$ 201,679.14
285	Change in Monthly Bill					$ 19,148.40				$ 16,806.60
286	Percent Change in Bill without Gas Cost					6.6%				6.2%
287	Percent Change in Bill with Gas Cost					1.2%				5.6%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Mainline Service - Over 500,000 Mcf per year, PNG transmission line

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
288	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
289	Customer Charge	12	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00
290	Riders:									
291	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
292	DSIC	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
293	TRS	12	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)
294	Total Monthly Charge		$ 5,595.40	$ 67,144.78	$ 5,877.40	$ 70,528.78	$ 5,595.40	$ 67,144.78	$ 5,877.40	$ 70,528.78
295	Volumetric Charges	Usage (Mcf)								
296	Delivery Charge per Mcf	2,100,000	$ 0.7430	$ 1,560,300.00	$ 0.7470	$ 1,568,768.39	$ 0.7430	$ 1,560,300.00	$ 0.7470	$ 1,568,768.39
297	Riders:									
298	STAS	2,100,000	$ 0.0005	$ 1,092.21	$ -	$ -	$ 0.0005	$ 1,092.21	$ -	$ -
299	MFC	2,100,000	$ 0.0256	$ 53,760.00	$ 0.0327	$ 68,642.19	$ -	$ -	$ -	$ -
300	GPC	2,100,000	$ 0.0865	$ 181,650.00	$ 0.0984	$ 206,640.00	$ -	$ -	$ -	$ -
301	DSIC	2,100,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
302	TRS	2,100,000	$ (0.0046)	$ (9,589.60)	$ (0.0046)	$ (9,589.60)	$ (0.0046)	$ (9,589.60)	$ (0.0046)	$ (9,589.60)
303	Total Delivery Rate per Mcf		$ 0.8511	$ 1,787,212.61	$ 0.8736	$ 1,834,460.97	$ 0.7390	$ 1,551,802.61	$ 0.7425	$ 1,559,178.78
304	Annual Bill without Gas Cost			$ 1,854,357.38		$ 1,904,989.75		$ 1,618,947.38		$ 1,629,707.56
305	Average Monthly Bill without Gas Cost			$ 154,529.78		$ 158,749.15		$ 134,912.28		$ 135,808.96
306	Gas Cost 1/	2,100,000	$ 7.7219	$ 16,215,967.16	$ 7.7219	$ 16,215,967.16	$ 0.1740	$ 365,400.00	$ 0.1740	$ 365,400.00
307	Total Rate per Mcf with Gas Cost		$ 8.5729		$ 8.5954		$ 0.9130		$ 0.9165	
308	Annual Bill with Gas Cost			$ 18,070,324.55		$ 18,120,956.91		$ 1,984,347.38		$ 1,995,107.56
309	Average Monthly Bill with Gas Cost			$ 1,505,860.38		$ 1,510,079.74		$ 165,362.28		$ 166,258.96
310	Change in Annual Bill					$ 50,632.36				$ 10,760.18
311	Change in Monthly Bill					$ 4,219.36				$ 896.68
312	Percent Change in Bill without Gas Cost					2.7%				0.7%
313	Percent Change in Bill with Gas Cost					0.3%				0.5%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

Mainline Service - Over 500,000 Mcf per year, Interstate pipeline

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
314	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
315	Customer Charge	12	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00
316	Riders:									
317	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
318	DSIC	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
319	TRS	12	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)
320	Total Monthly Charge		$ 5,595.40	$ 67,144.78	$ 5,877.40	$ 70,528.78	$ 5,595.40	$ 67,144.78	$ 5,877.40	$ 70,528.78
321	Volumetric Charges	Usage (Mcf)								
322	Delivery Charge per Mcf	2,100,000	$ 0.4422	$ 928,620.00	$ 0.4446	$ 933,660.00	$ 0.4422	$ 928,620.00	$ 0.4446	$ 933,660.00
323	Riders:									
324	STAS	2,100,000	$ 0.0003	$ 650.03	$ -	$ -	$ 0.0013	$ 2,712.82	$ -	$ -
325	MFC	2,100,000	$ 0.0256	$ 53,760.00	$ 0.0327	$ 68,642.19	$ -	$ -	$ -	$ -
326	GPC	2,100,000	$ 0.0865	$ 181,650.00	$ 0.0984	$ 206,640.00	$ -	$ -	$ -	$ -
327	DSIC	2,100,000	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
328	TRS	2,100,000	$ (0.0027)	$ (5,707.30)	$ (0.0027)	$ (5,707.30)	$ (0.0113)	$ (23,818.53)	$ (0.0027)	$ (5,707.30)
329	Total Delivery Rate per Mcf		$ 0.5519	$ 1,158,972.74	$ 0.5730	$ 1,203,234.89	$ 0.4321	$ 907,514.29	$ 0.4419	$ 927,952.70
330	Annual Bill without Gas Cost			$ 1,226,117.51		$ 1,273,763.67		$ 974,659.06		$ 998,481.48
331	Average Monthly Bill without Gas Cost			$ 102,176.46		$ 106,146.97		$ 81,221.59		$ 83,206.79
332	Gas Cost 1/	2,100,000	$ 7.7219	$ 16,215,967.16	$ 7.7219	$ 16,215,967.16	$ 0.1740	$ 365,400.00	$ 0.1740	$ 365,400.00
333	Total Rate per Mcf with Gas Cost		$ 8.2738		$ 8.2949		$ 0.6061		$ 0.6159	
334	Annual Bill with Gas Cost			$ 17,442,084.68		$ 17,489,730.83		$ 1,340,059.06		$ 1,363,881.48
335	Average Monthly Bill with Gas Cost			$ 1,453,507.06		$ 1,457,477.57		$ 111,671.59		$ 113,656.79
336	Change in Annual Bill					$ 47,646.16				$ 23,822.41
337	Change in Monthly Bill					$ 3,970.51				$ 1,985.20
338	Percent Change in Bill without Gas Cost					3.9%				2.4%
339	Percent Change in Bill with Gas Cost					0.3%				1.8%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

TRANSITIONAL - Large General Service - 100,000 - 199,999 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
340	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
341	Customer Charge	12	$ 2,130.00	$ 25,560.00	$2,237.00	$ 26,844.00	$ 2,130.00	$ 25,560.00	$2,237.00	$ 26,844.00
342	Riders:									
343	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
344	DSIC	12	$ 106.5000	$ 1,278.00	$0.0000	$ -	$ 106.5000	$ 1,278.00	$0.0000	$ -
345	TRS	12	$ (13.0910)	$ (157.09)	$ (13.0910)	$ (157.09)	$ (13.0910)	$ (157.09)	$ (13.0910)	$ (157.09)
346	Total Monthly Charge		$ 2,223.41	$ 26,680.91	$ 2,223.91	$ 26,686.91	$ 2,223.41	$ 26,680.91	$ 2,223.91	$ 26,686.91
347	Volumetric Charges	Usage (Mcf)								
348	Delivery Charge per Mcf	150,000	$ 1.4012	$ 210,180.00	$ 1.5655	$ 234,827.11	$ 1.4012	$ 210,180.00	$ 1.5655	$ 234,827.11
349	Riders:									
350	STAS	150,000	$ 0.0017	$ 255.52	$ -	$ -	$ 0.0017	$ 255.52	$ -	$ -
351	MFC	150,000	$ 0.0256	$ 3,840.00	$ 0.0327	$ 4,903.01	$ -	$ -	$ -	$ -
352	GPC	150,000	$ 0.0865	$ 12,975.00	$ 0.0984	$ 14,760.00	$ -	$ -	$ -	$ -
353	DSIC	150,000	$ 0.1273	$ 19,092.00	$ -	$ -	$ 0.1217	$ 18,251.25	$ -	$ -
354	TRS	150,000	$ (0.0150)	$ (2,243.44)	$ (0.0150)	$ (2,243.44)	$ (0.0150)	$ (2,243.44)	$ (0.0150)	$ (2,243.44)
355	Total Delivery Rate per Mcf		$ 1.6273	$ 244,099.07	$ 1.6816	$ 252,246.68	$ 1.5096	$ 226,443.32	$ 1.5506	$ 232,583.66
356	Annual Bill without Gas Cost			$ 270,779.98		$ 278,933.59		$ 253,124.23		$ 259,270.57
357	Average Monthly Bill without Gas Cost			$ 22,565.00		$ 23,244.47		$ 21,093.69		$ 21,605.88
358	Gas Cost 1/	150,000	$ 7.7219	$ 1,158,283.37	$ 7.7219	$ 1,158,283.37	$ 0.1740	$ 26,100.00	$ 0.1740	$ 26,100.00
359	Total Rate per Mcf with Gas Cost		$ 9.3492		$ 9.4035		$ 1.6836		$ 1.7246	
360	Annual Bill with Gas Cost			$ 1,429,063.35		$ 1,437,216.96		$ 279,224.23		$ 285,370.57
361	Average Monthly Bill with Gas Cost			$ 119,088.61		$ 119,768.08		$ 23,268.69		$ 23,780.88
362	Change in Annual Bill					$ 8,153.60				$ 6,146.34
363	Change in Monthly Bill					$ 679.47				$ 512.20
364	Percent Change in Bill without Gas Cost					3.0%				2.4%
365	Percent Change in Bill with Gas Cost					0.6%				2.2%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

TRANSITIONAL - Large General Service - 200,000 to 749,999 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
366	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
367	Customer Charge	12	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00
368	Riders:									
369	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
370	DSIC	12	$ 281.5000	$ 3,378.00	$0.0000	$ -	$ 281.5000	$ 3,378.00	$0.0000	$ -
371	TRS	12	$ (34.6020)	$ (415.22)	-$34.6020	$ (415.22)	$ (34.6020)	$ (415.22)	-$34.6020	$ (415.22)
372	Total Monthly Charge		$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78	$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78
373	Volumetric Charges	Usage (Mcf)								
374	Delivery Charge per Mcf	475,000	$ 1.1754	$ 558,315.00	$ 1.3132	$ 623,786.74	$ 1.1754	$ 558,315.00	$ 1.3132	$ 623,786.74
375	Riders:									
376	STAS	475,000	$ 0.0015	$ 729.41	$ -	$ -	$ 0.0015	$ 729.41	$ -	$ -
377	MFC	475,000	$ 0.0256	$ 12,160.00	$ 0.0327	$ 15,526.21	$ -	$ -	$ -	$ -
378	GPC	475,000	$ 0.0865	$ 41,087.50	$ 0.0984	$ 46,740.00	$ -	$ -	$ -	$ -
379	DSIC	475,000	$ 0.1153	$ 54,762.75	$ -	$ -	$ 0.1097	$ 52,100.38	$ -	$ -
380	TRS	475,000	$ (0.0135)	$ (6,404.18)	$ (0.0135)	$ (6,404.18)	$ (0.0135)	$ (6,404.18)	$ (0.0135)	$ (6,404.18)
381	Total Delivery Rate per Mcf		$ 1.3908	$ 660,650.48	$ 1.4308	$ 679,648.77	$ 1.2731	$ 604,740.60	$ 1.2998	$ 617,382.56
382	Annual Bill without Gas Cost			$ 731,173.25		$ 750,177.55		$ 675,263.38		$ 687,911.34
383	Average Monthly Bill without Gas Cost			$ 60,931.10		$ 62,514.80		$ 56,271.95		$ 57,325.94
384	Gas Cost 1/	475,000	$ 7.7219	$ 3,667,897.33	$ 7.7219	$ 3,667,897.33	$ 0.1740	$ 82,650.00	$ 0.1740	$ 82,650.00
385	Total Rate per Mcf with Gas Cost		$ 9.1127		$ 9.1527		$ 1.4471		$ 1.4738	
386	Annual Bill with Gas Cost			$ 4,399,070.59		$ 4,418,074.88		$ 757,913.38		$ 770,561.34
387	Average Monthly Bill with Gas Cost			$ 366,589.22		$ 368,172.91		$ 63,159.45		$ 64,213.44
388	Change in Annual Bill					$ 19,004.29				$ 12,647.96
389	Change in Monthly Bill					$ 1,583.69				$ 1,054.00
390	Percent Change in Bill without Gas Cost					2.6%				1.9%
391	Percent Change in Bill with Gas Cost					0.4%				1.7%

1/ balancing charge for Transport

Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

TRANSITIONAL - Large General Service - 750,000 to 1,999,999 Mcf per year

Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
392	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
393	Customer Charge	12	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00
394	Riders:									
395	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
396	DSIC	12	$ 281.5000	$ 3,378.00	$0.0000	$ -	$ 281.5000	$ 3,378.00	$0.0000	$ -
397	TRS	12	$ (34.6020)	$ (415.22)	-$34.6020	$ (415.22)	$ (34.6020)	$ (415.22)	-$34.6020	$ (415.22)
398	Total Monthly Charge		$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78	$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78
399	Volumetric Charges	Usage (Mcf)								
400	Delivery Charge per Mcf	1,375,000	$ 1.1754	$ 1,616,175.00	$ 1.3132	$ 1,805,698.46	$ 1.1754	$ 1,616,175.00	$ 1.3132	$ 1,805,698.46
401	Riders:									
402	STAS	1,375,000	$ 0.0013	$ 1,838.09	$ -	$ -	$ 0.0013	$ 1,838.09	$ -	$ -
403	MFC	1,375,000	$ 0.0256	$ 35,200.00	$ 0.0327	$ 44,944.29	$ -	$ -	$ -	$ -
404	GPC	1,375,000	$ 0.0865	$ 118,937.50	$ 0.0984	$ 135,300.00	$ -	$ -	$ -	$ -
405	DSIC	1,375,000	$ 0.1011	$ 138,998.75	$ -	$ -	$ 0.0955	$ 131,291.88	$ -	$ -
406	TRS	1,375,000	$ (0.0117)	$ (16,138.40)	$ (0.0117)	$ (16,138.40)	$ (0.0117)	$ (16,138.40)	$ (0.0117)	$ (16,138.40)
407	Total Delivery Rate per Mcf		$ 1.3782	$ 1,895,010.94	$ 1.4326	$ 1,969,804.35	$ 1.2605	$ 1,733,166.56	$ 1.3015	$ 1,789,560.06
408	Annual Bill without Gas Cost			$ 1,965,533.72		$ 2,040,333.13		$ 1,803,689.34		$ 1,860,088.83
409	Average Monthly Bill without Gas Cost			$ 163,794.48		$ 170,027.76		$ 150,307.45		$ 155,007.40
410	Gas Cost 1/	1,375,000	$ 7.7219	$ 10,617,597.55	$ 7.7219	$ 10,617,597.55	$ 0.1740	$ 239,250.00	$ 0.1740	$ 239,250.00
411	Total Rate per Mcf with Gas Cost		$ 9.1001		$ 9.1545		$ 1.4345		$ 1.4755	
412	Annual Bill with Gas Cost			$ 12,583,131.26		$ 12,657,930.67		$ 2,042,939.34		$ 2,099,338.83
413	Average Monthly Bill with Gas Cost			$ 1,048,594.27		$ 1,054,827.56		$ 170,244.95		$ 174,944.90
414	Change in Annual Bill					$ 74,799.41				$ 56,399.49
415	Change in Monthly Bill					$ 6,233.28				$ 4,699.96
416	Percent Change in Bill without Gas Cost					3.8%				3.1%
417	Percent Change in Bill with Gas Cost					0.6%				2.8%

1/ balancing charge for Transport

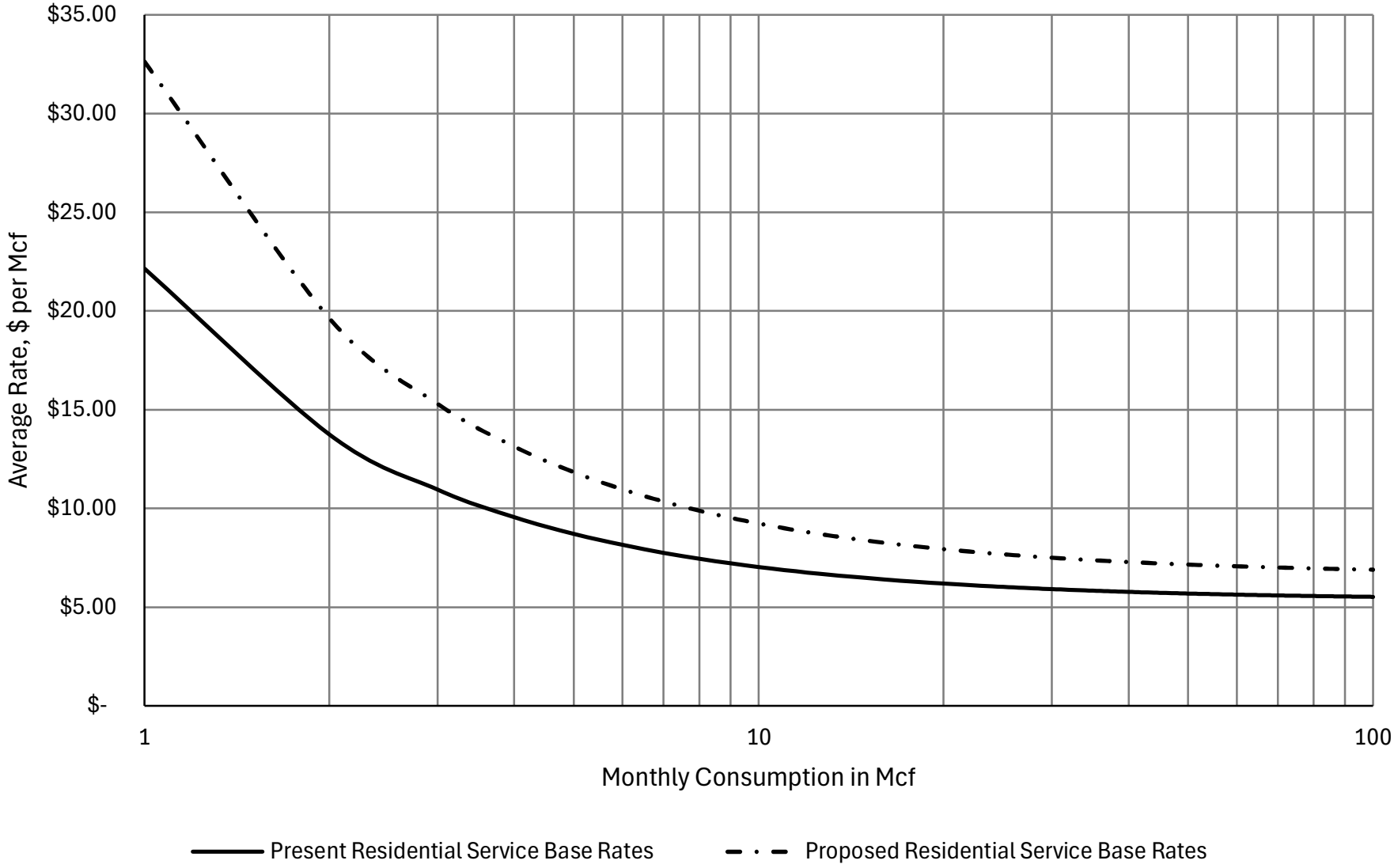
Peoples Natural Gas Company LLC
12 Months Ending December 31, 2027
Peoples Exhibit JDT-5 - Bill Impacts

TRANSITIONAL - Large General Service - Over 2,000,000 Mcf per year

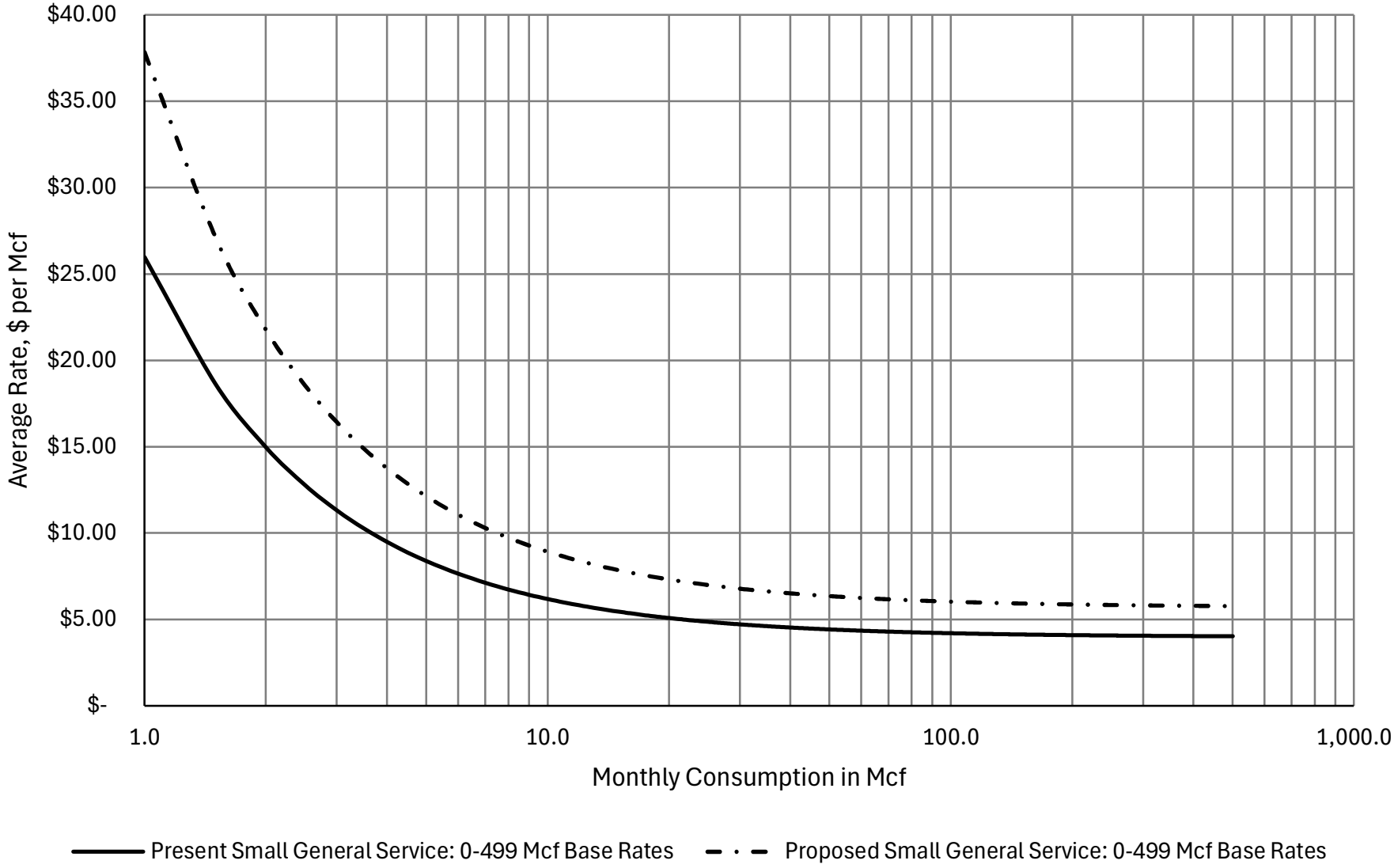
Line	(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)
			RETAIL				TRANSPORT			
			Current Rates		Proposed Rates		Current Rates		Proposed Rates	
418	Monthly Charges	Bills	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount	Rate	Annual Amount
419	Customer Charge	12	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00	$ 5,630.00	$ 67,560.00	$5,912.00	$ 70,944.00
420	Riders:									
421	Supplier Choice	12	$ -	$ -	$0.0000	$ -	$ -	$ -	$0.0000	$ -
422	DSIC	12	$ 281.5000	$ 3,378.00	$0.0000	$ -	$ 281.5000	$ 3,378.00	$0.0000	$ -
423	TRS	12	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)	$ (34.6020)	$ (415.22)
424	Total Monthly Charge		$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78	$ 5,876.90	$ 70,522.78	$ 5,877.40	$ 70,528.78
425	Volumetric Charges	Usage (Mcf)								
426	Delivery Charge per Mcf	2,100,000	$ 1.1754	$ 2,468,340.00	$ 1.3132	$ 2,757,794.01	$ 1.1754	$ 2,468,340.00	$ 1.3132	$ 2,757,794.01
427	Riders:									
428	STAS	2,100,000	$ 0.0010	$ 2,121.36	$ -	$ -	$ 0.0010	$ 2,121.36	$ -	$ -
429	MFC	2,100,000	$ 0.0256	$ 53,760.00	$ 0.0327	$ 68,642.19	$ -	$ -	$ -	$ -
430	GPC	2,100,000	$ 0.0865	$ 181,650.00	$ 0.0984	$ 206,640.00	$ -	$ -	$ -	$ -
431	DSIC	2,100,000	$ 0.0778	$ 163,296.00	$ -	$ -	$ 0.0722	$ 151,525.50	$ -	$ -
432	TRS	2,100,000	$ (0.0089)	$ (18,625.51)	$ (0.0089)	$ (18,625.51)	$ (0.0089)	$ (18,625.51)	$ (0.0089)	$ (18,625.51)
433	Total Delivery Rate per Mcf		$ 1.3574	$ 2,850,541.84	$ 1.4355	$ 3,014,450.68	$ 1.2397	$ 2,603,361.34	$ 1.3044	$ 2,739,168.49
434	Annual Bill without Gas Cost			$ 2,921,064.62		$ 3,084,979.46		$ 2,673,884.12		$ 2,809,697.27
435	Average Monthly Bill without Gas Cost			$ 243,422.05		$ 257,081.62		$ 222,823.68		$ 234,141.44
436	Gas Cost 1/	2,100,000	$ 7.7219	$ 16,215,967.16	$ 7.7219	$ 16,215,967.16	$ 0.1740	$ 365,400.00	$ 0.1740	$ 365,400.00
437	Total Rate per Mcf with Gas Cost		$ 9.0793		$ 9.1573		$ 1.4137		$ 1.4784	
438	Annual Bill with Gas Cost			$ 19,137,031.78		$ 19,300,946.62		$ 3,039,284.12		$ 3,175,097.27
439	Average Monthly Bill with Gas Cost			$ 1,594,752.65		$ 1,608,412.22		$ 253,273.68		$ 264,591.44
440	Change in Annual Bill					$ 163,914.84				$ 135,813.15
441	Change in Monthly Bill					$ 13,659.57				$ 11,317.76
442	Percent Change in Bill without Gas Cost					5.6%				5.1%
443	Percent Change in Bill with Gas Cost					0.9%				4.5%

1/ balancing charge for Transport

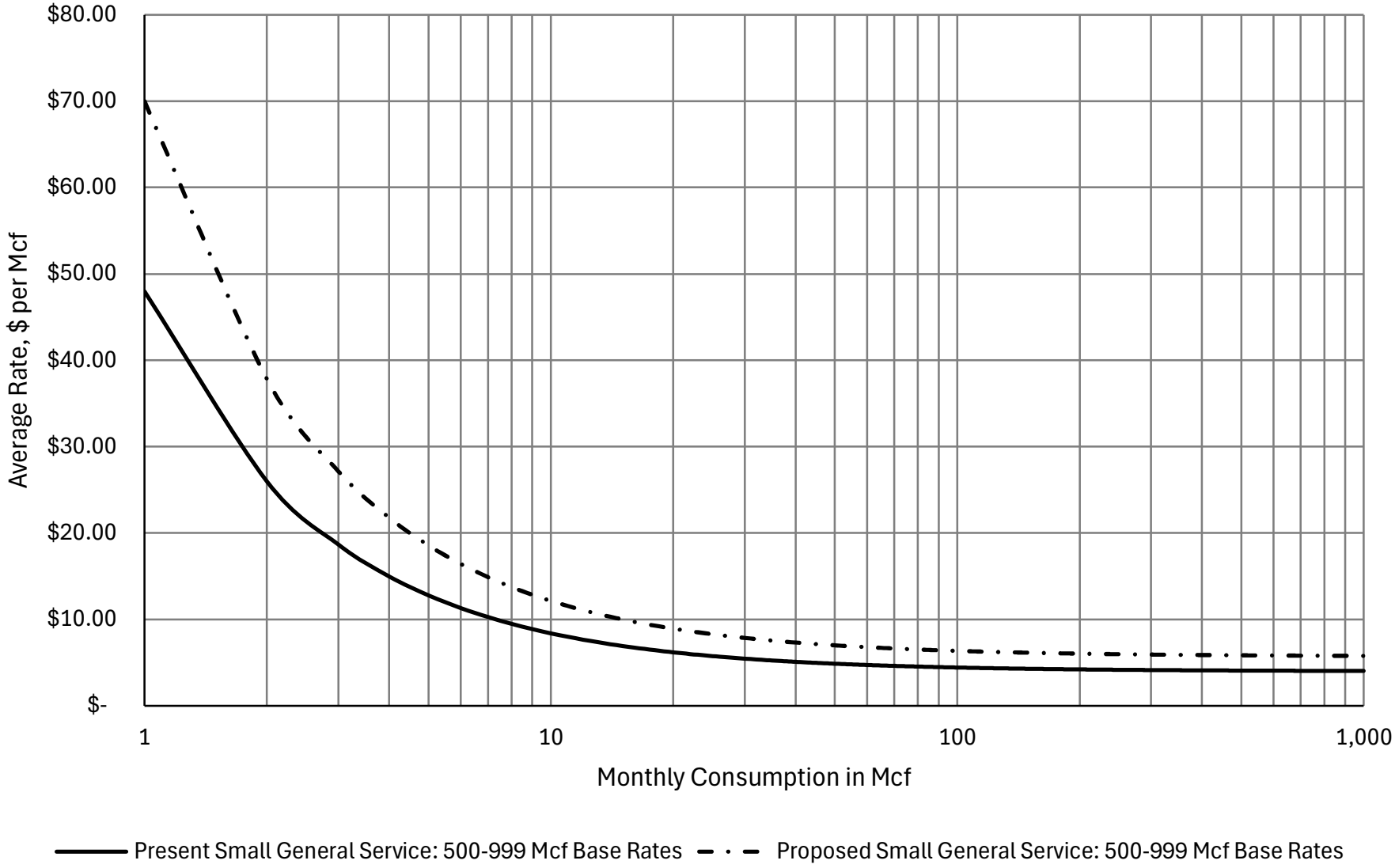
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Residential Service



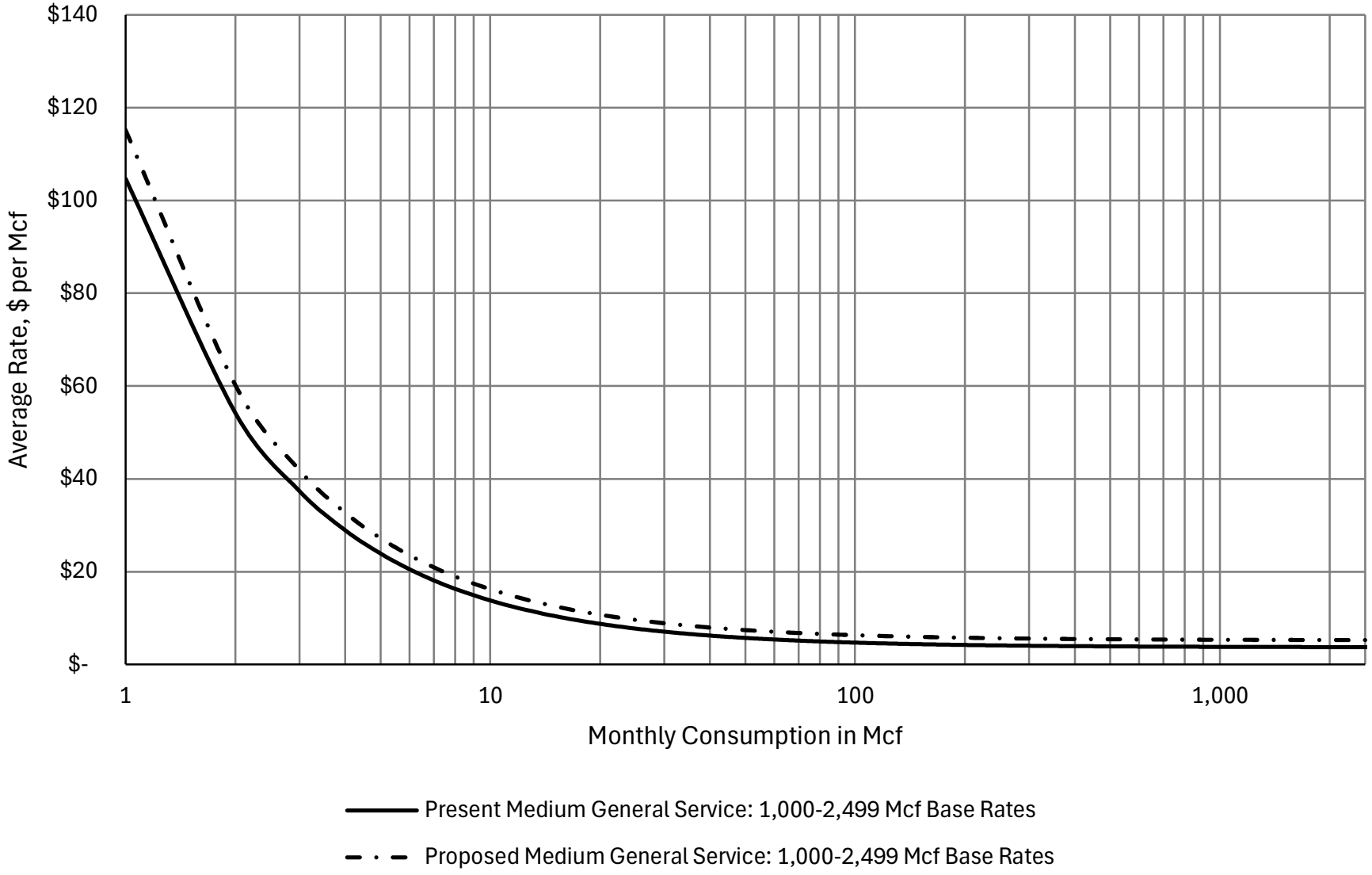
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Small General Service: 0-499 Mcf annual consumption



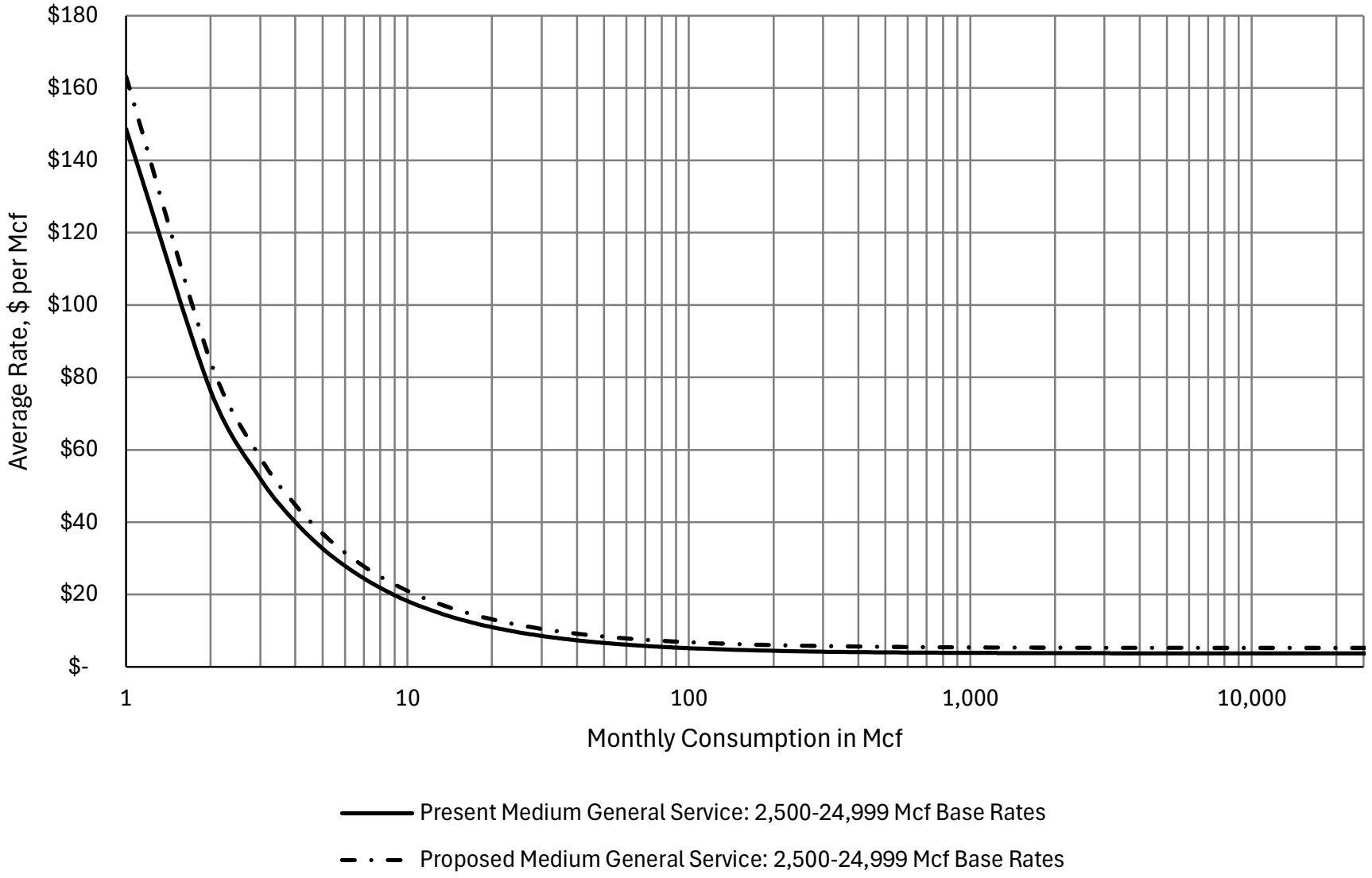
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Small General Service: 500-999 Mcf annual consumption



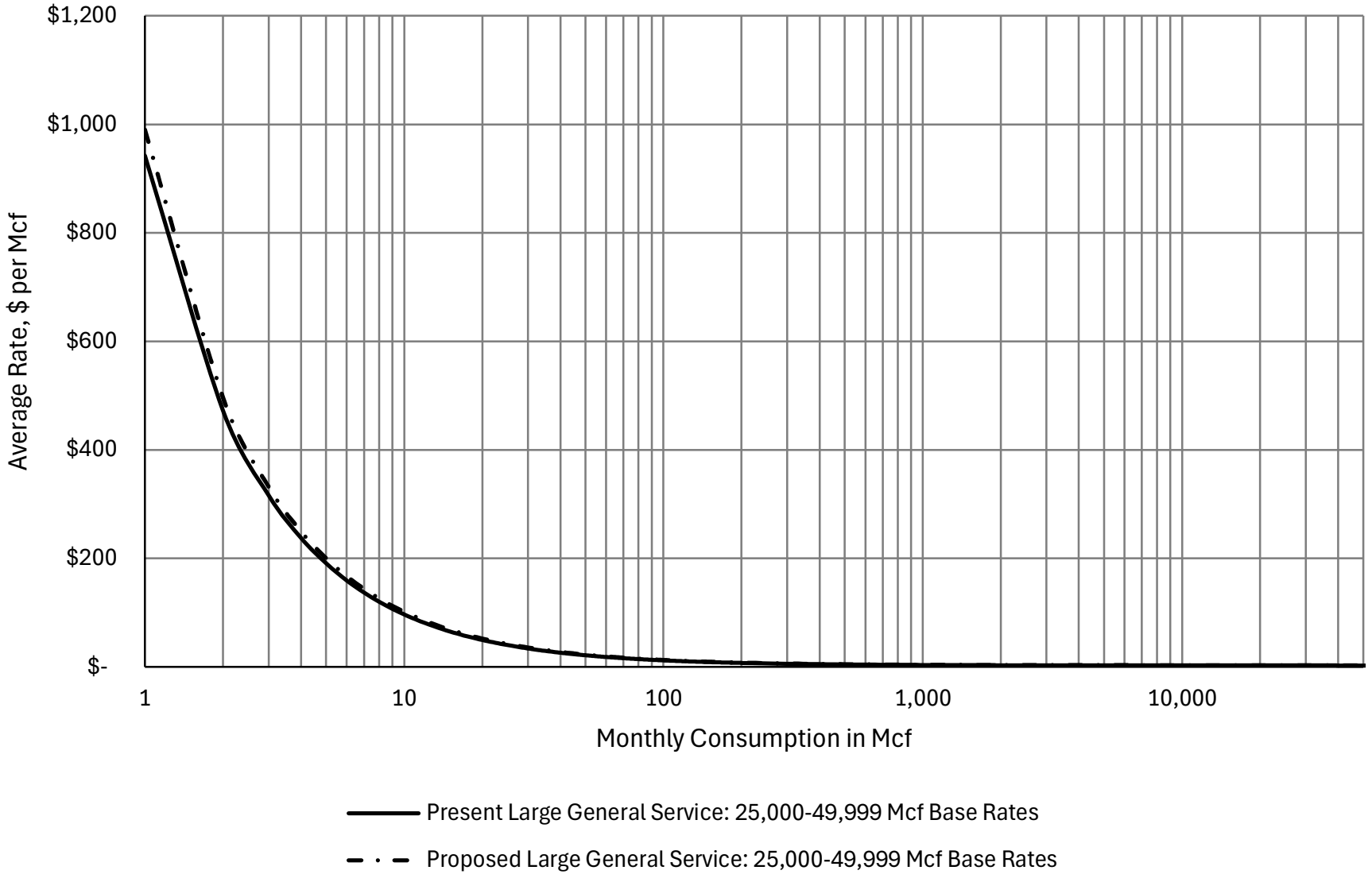
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Medium General Service: 1,000-2,499 Mcf annual consumption



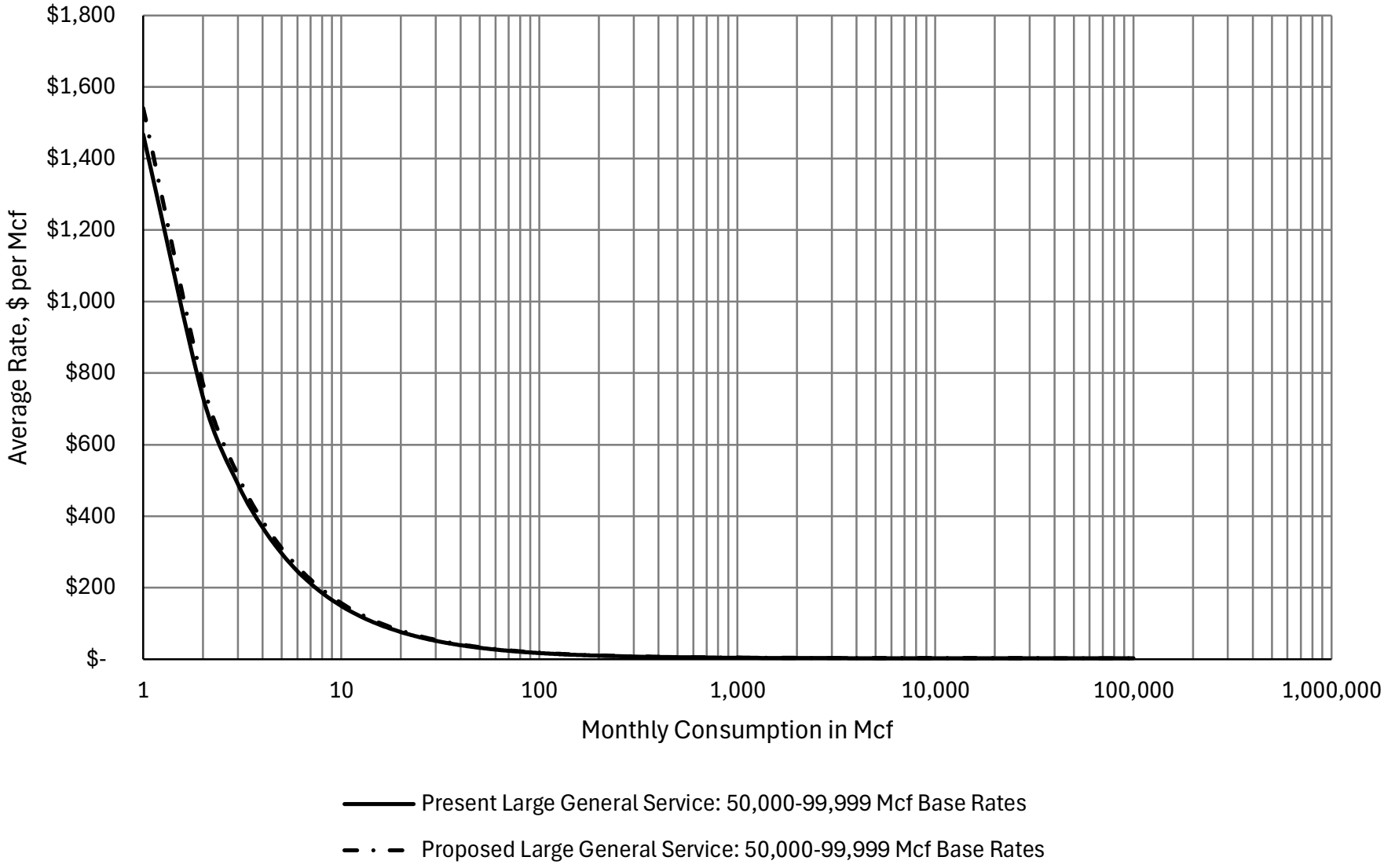
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Medium General Service: 2,500-24,999 Mcf annual consumption



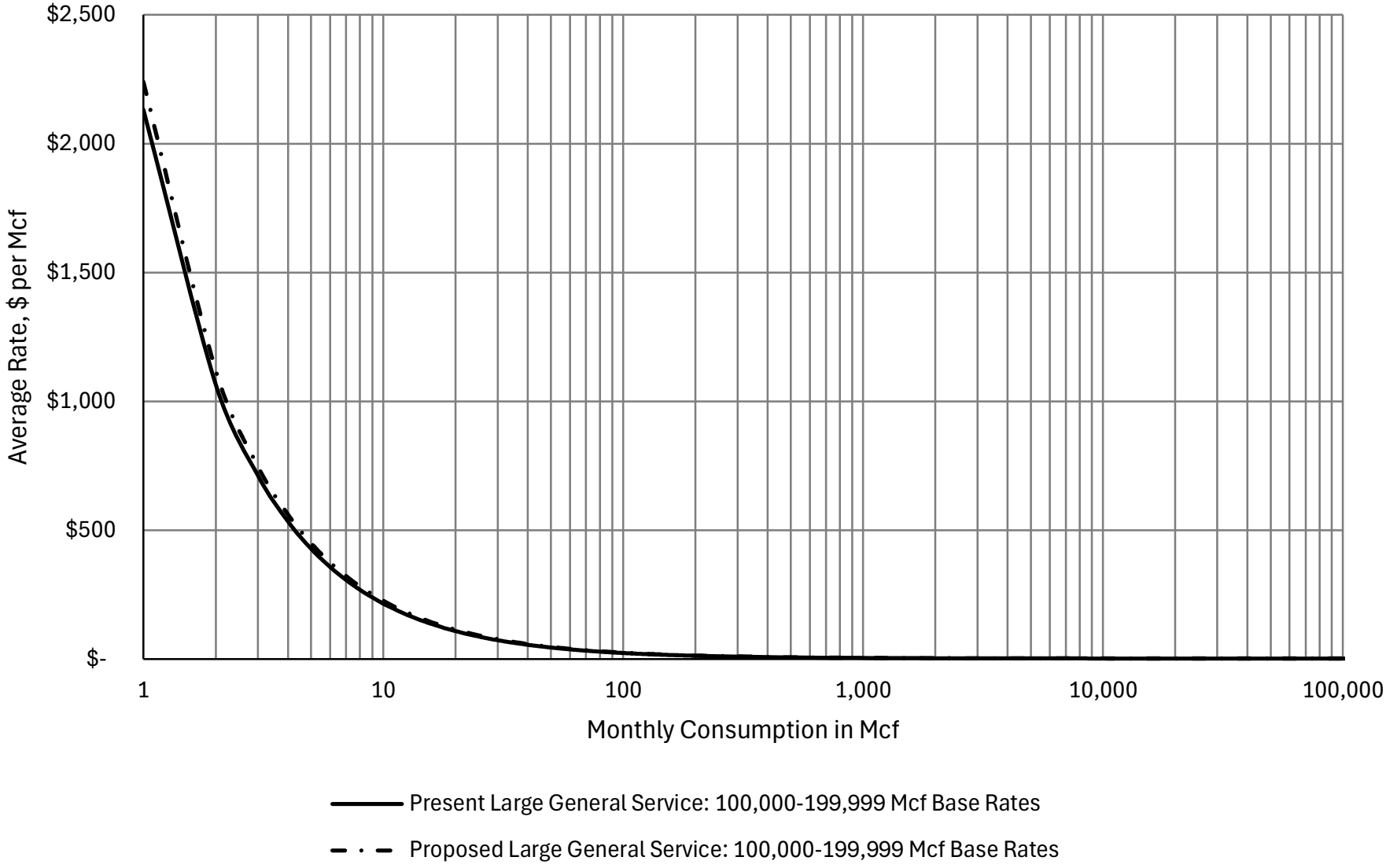
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Large General Service: 25,000-49,999 Mcf annual consumption



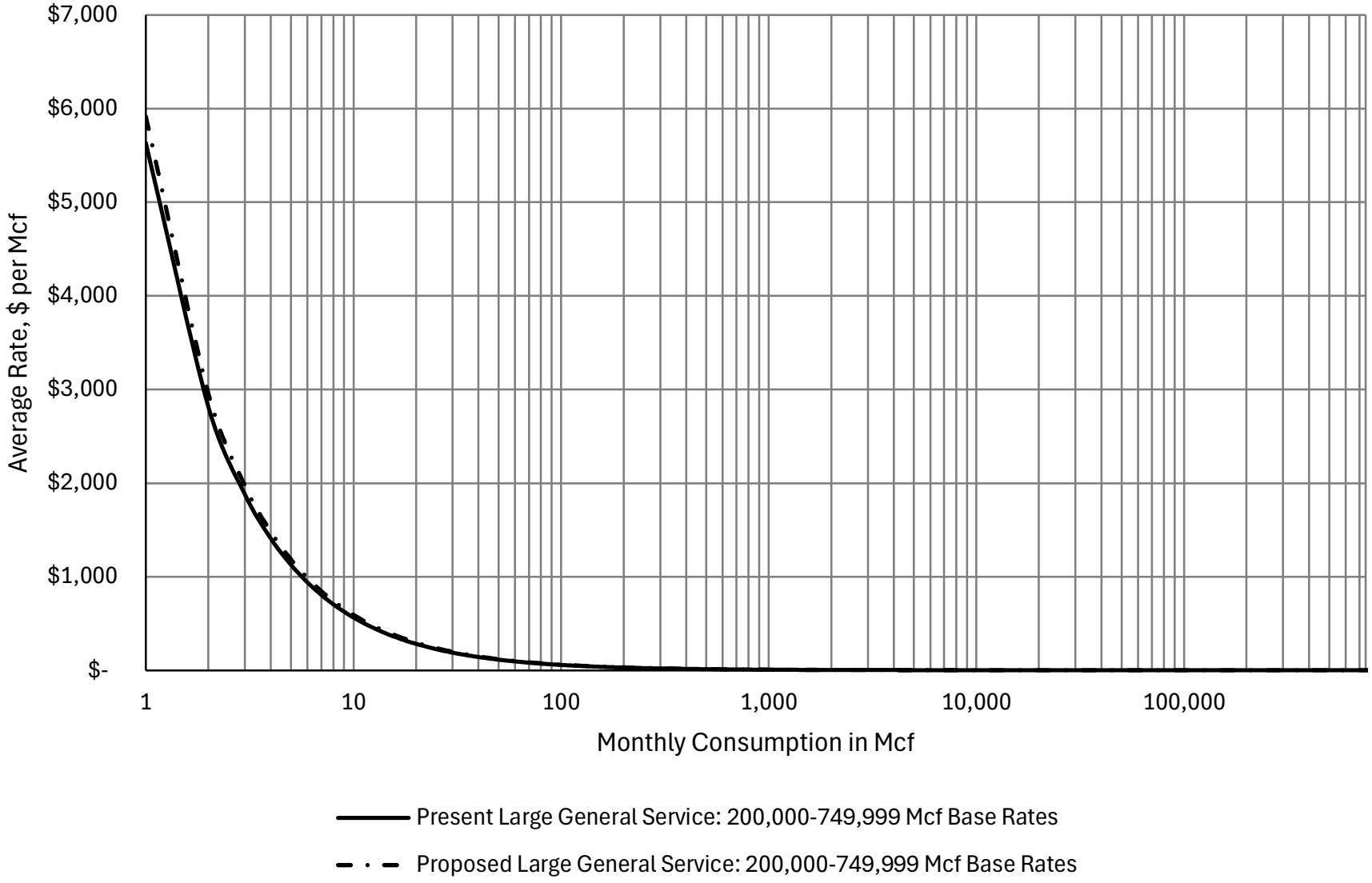
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Large General Service: 50,000-99,999 Mcf annual consumption



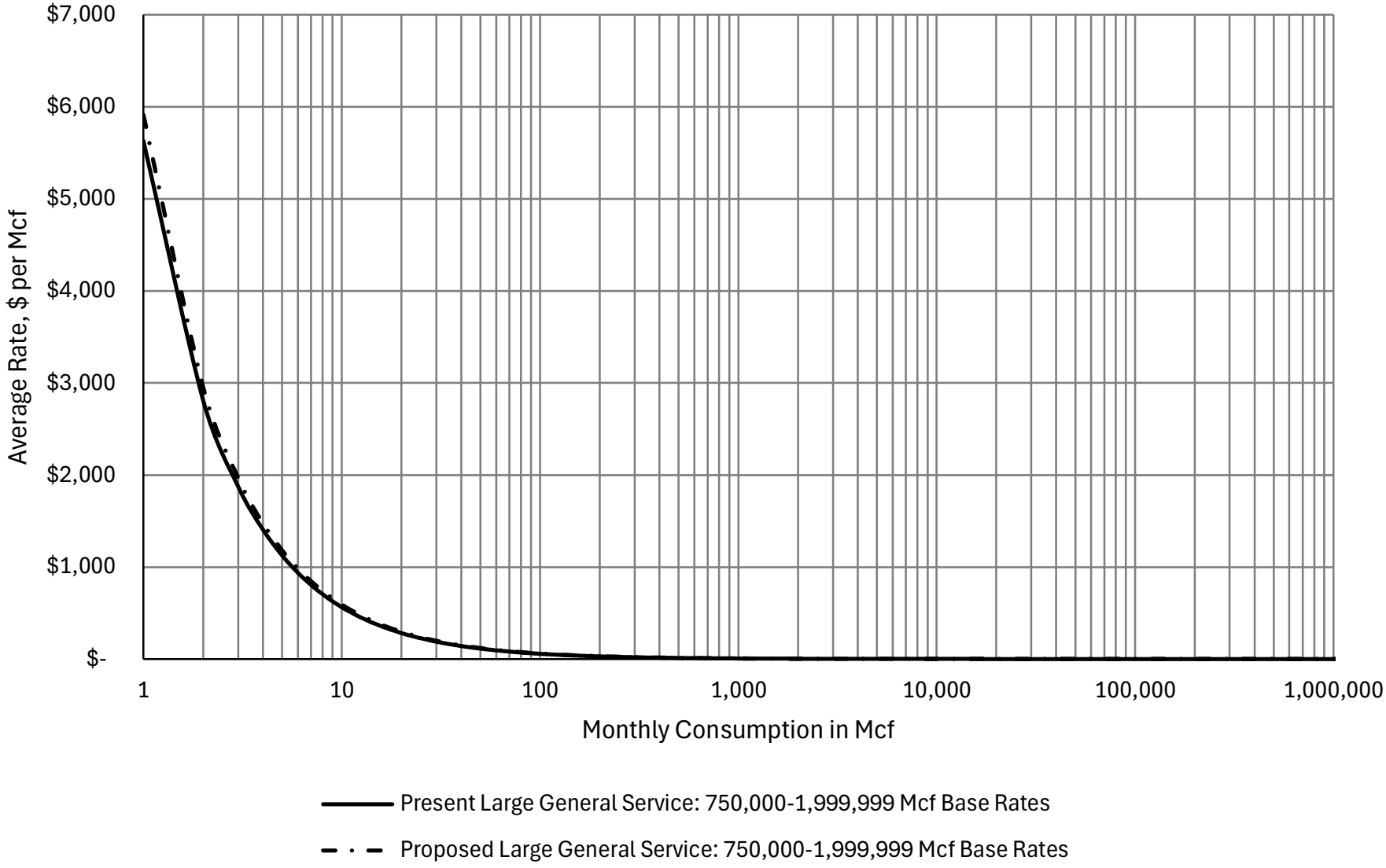
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Large General Service: 100,000-199,999 Mcf annual consumption



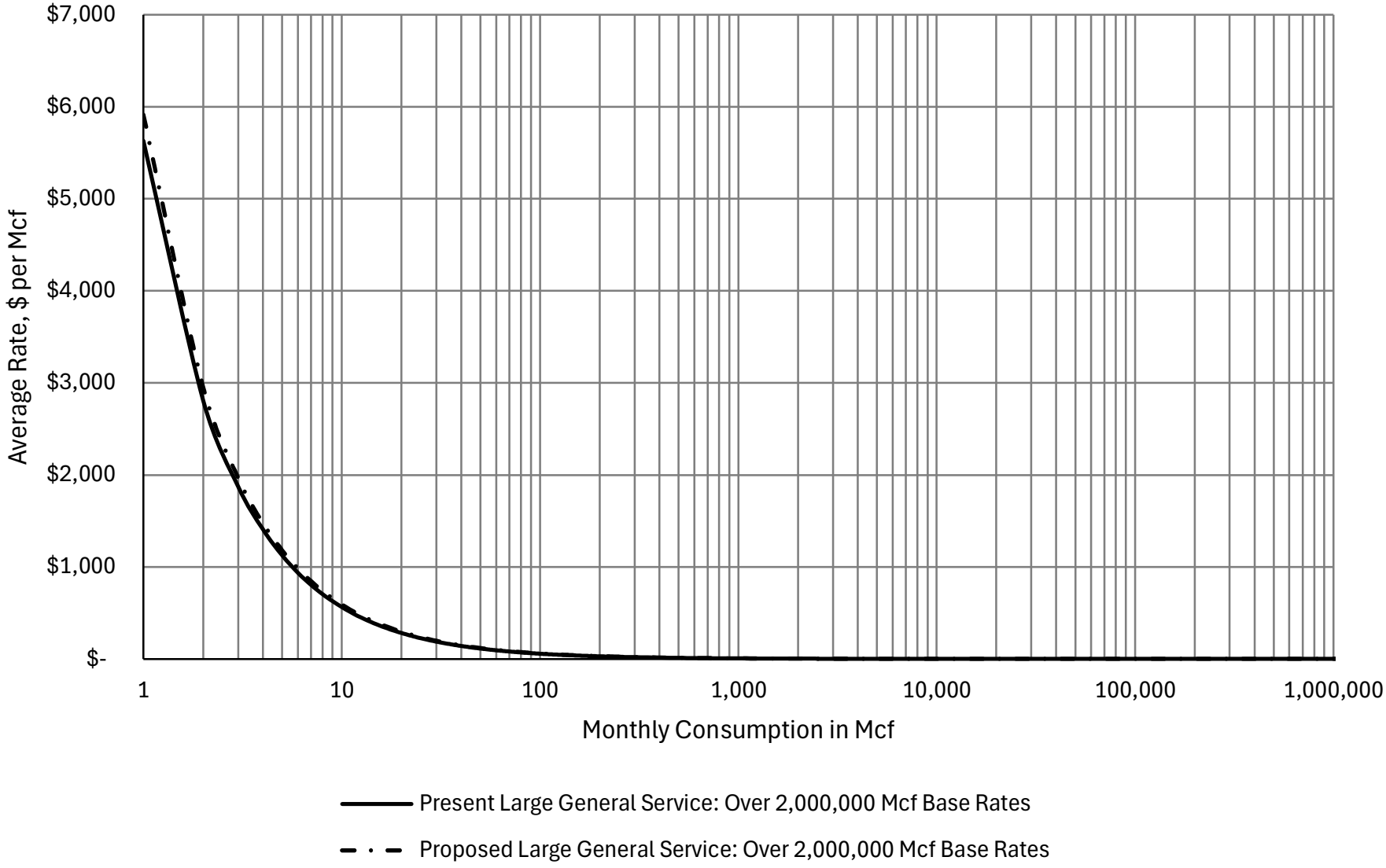
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Large General Service: 200,000-749,999 Mcf annual consumption



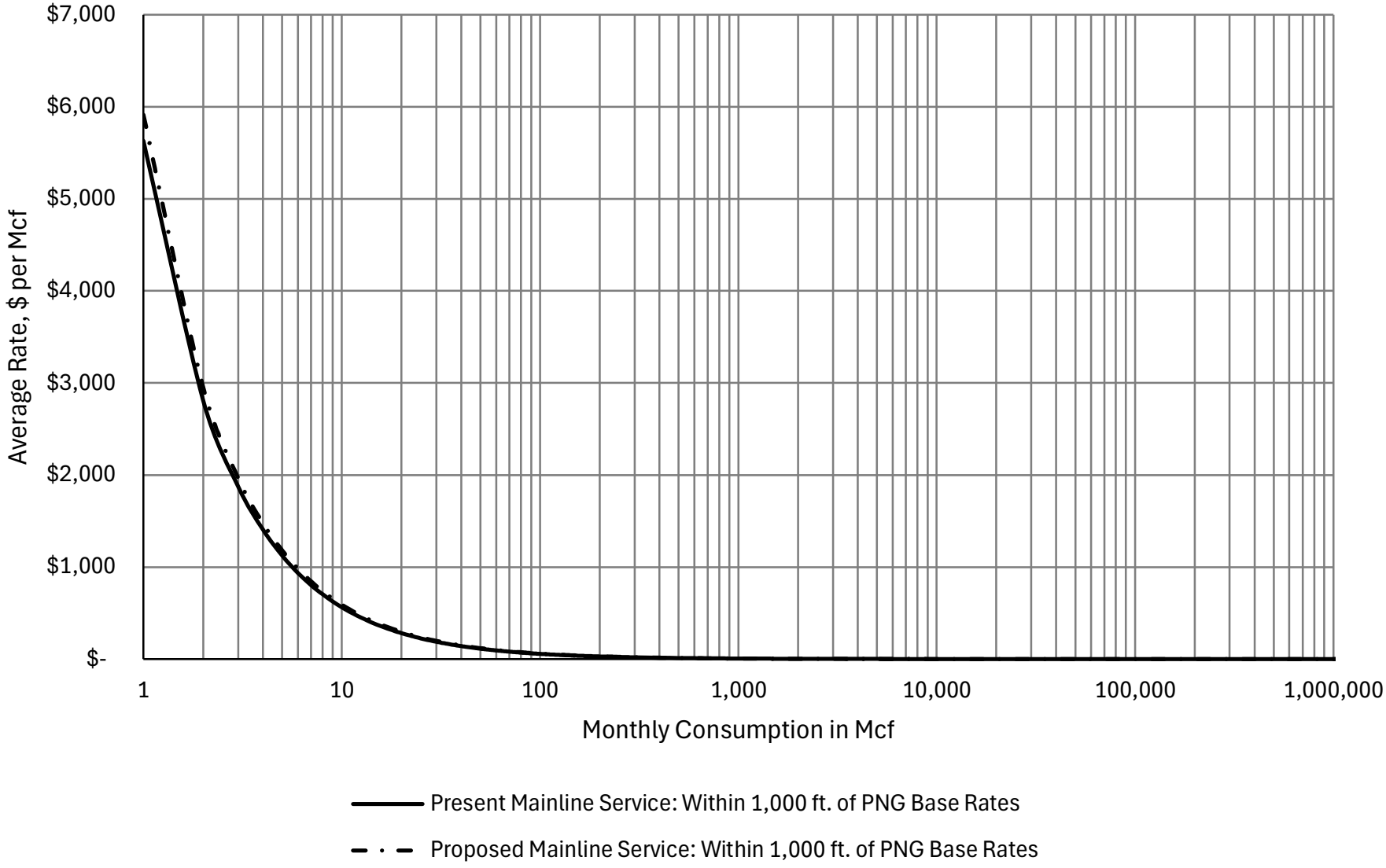
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Large General Service: 750,000-1,999,999 Mcf annual consumption



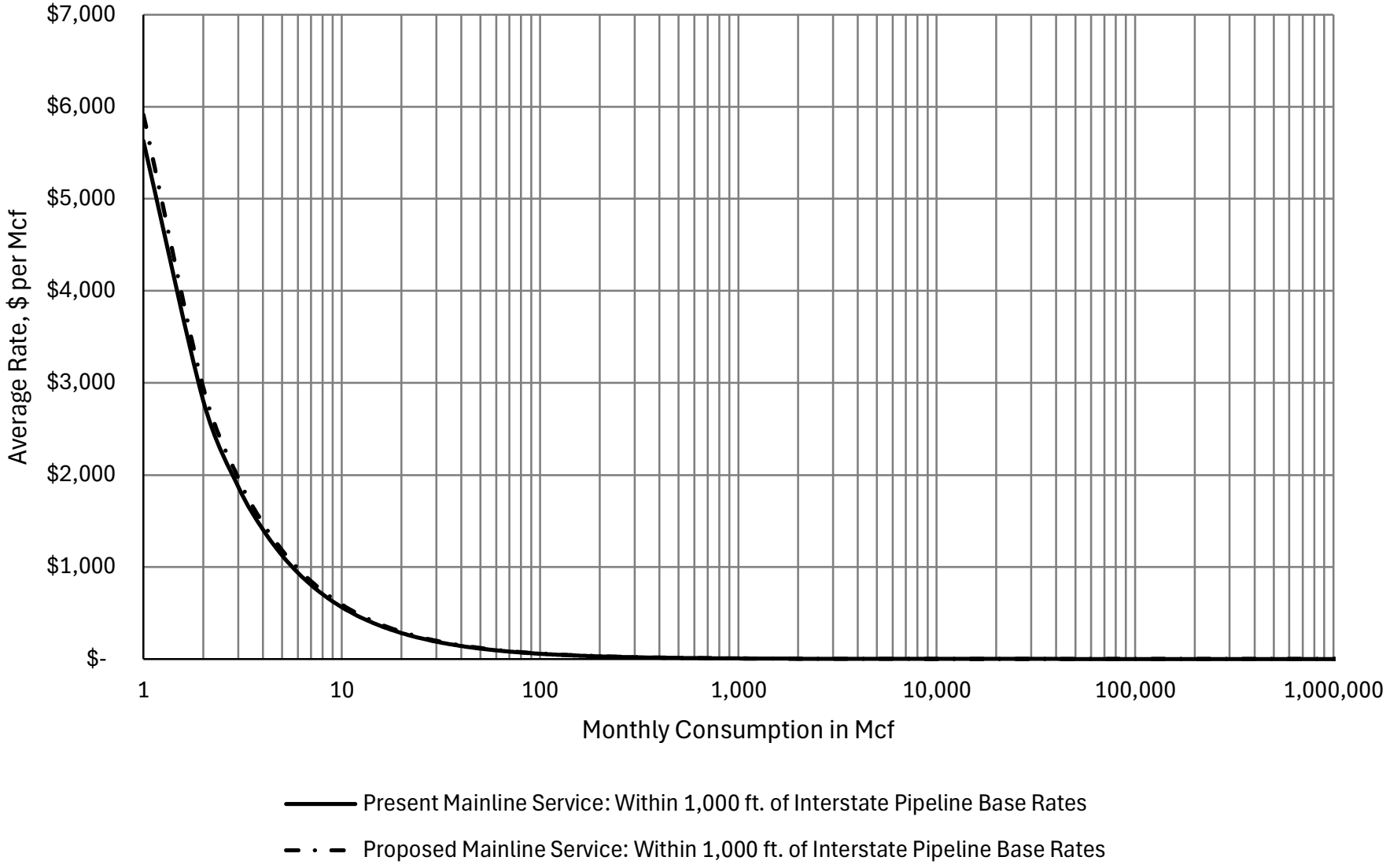
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Large General Service: Over 2,000,000 Mcf annual consumption



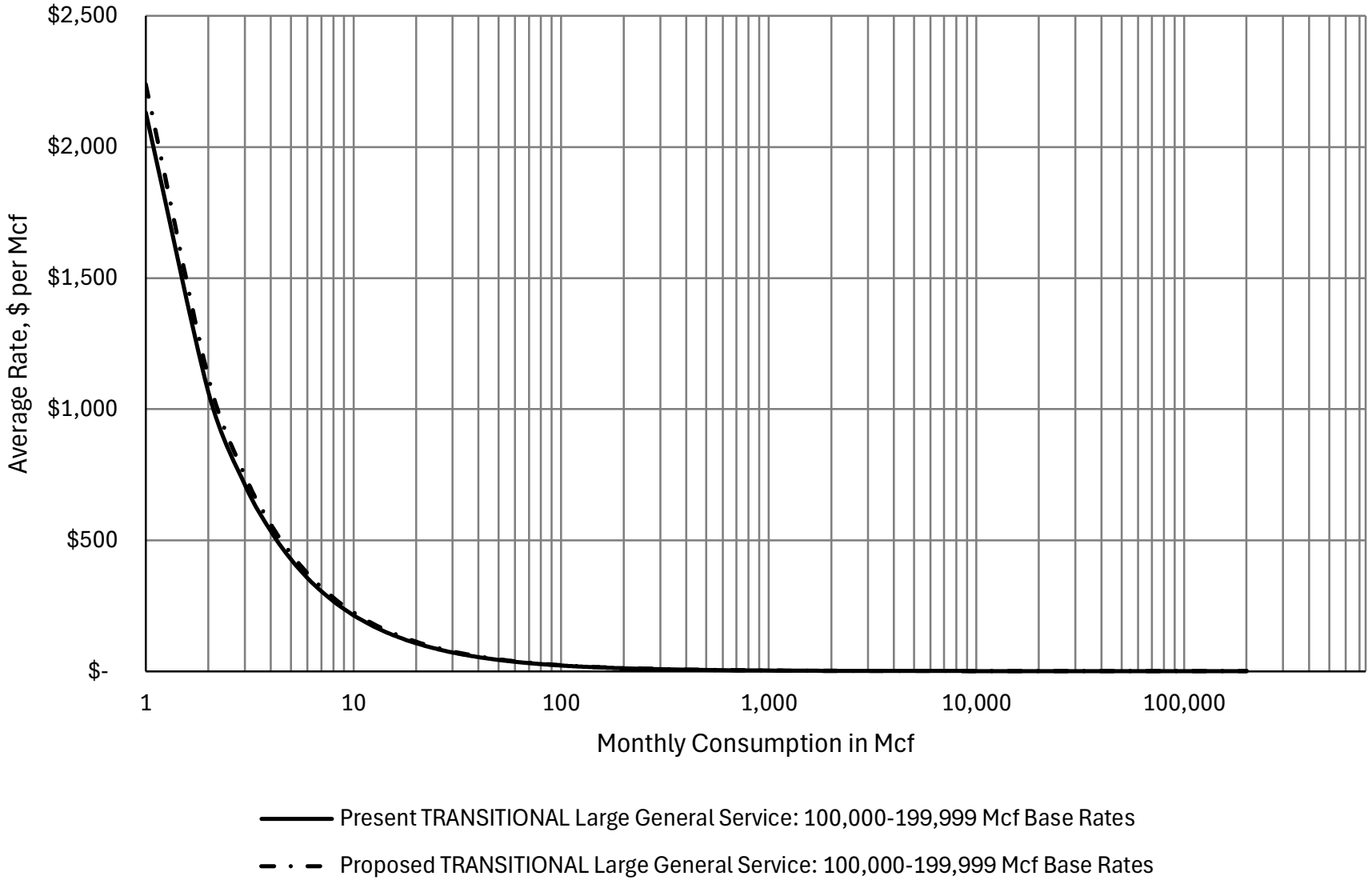
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Mainline Service: Within 1,000 ft. of PNG



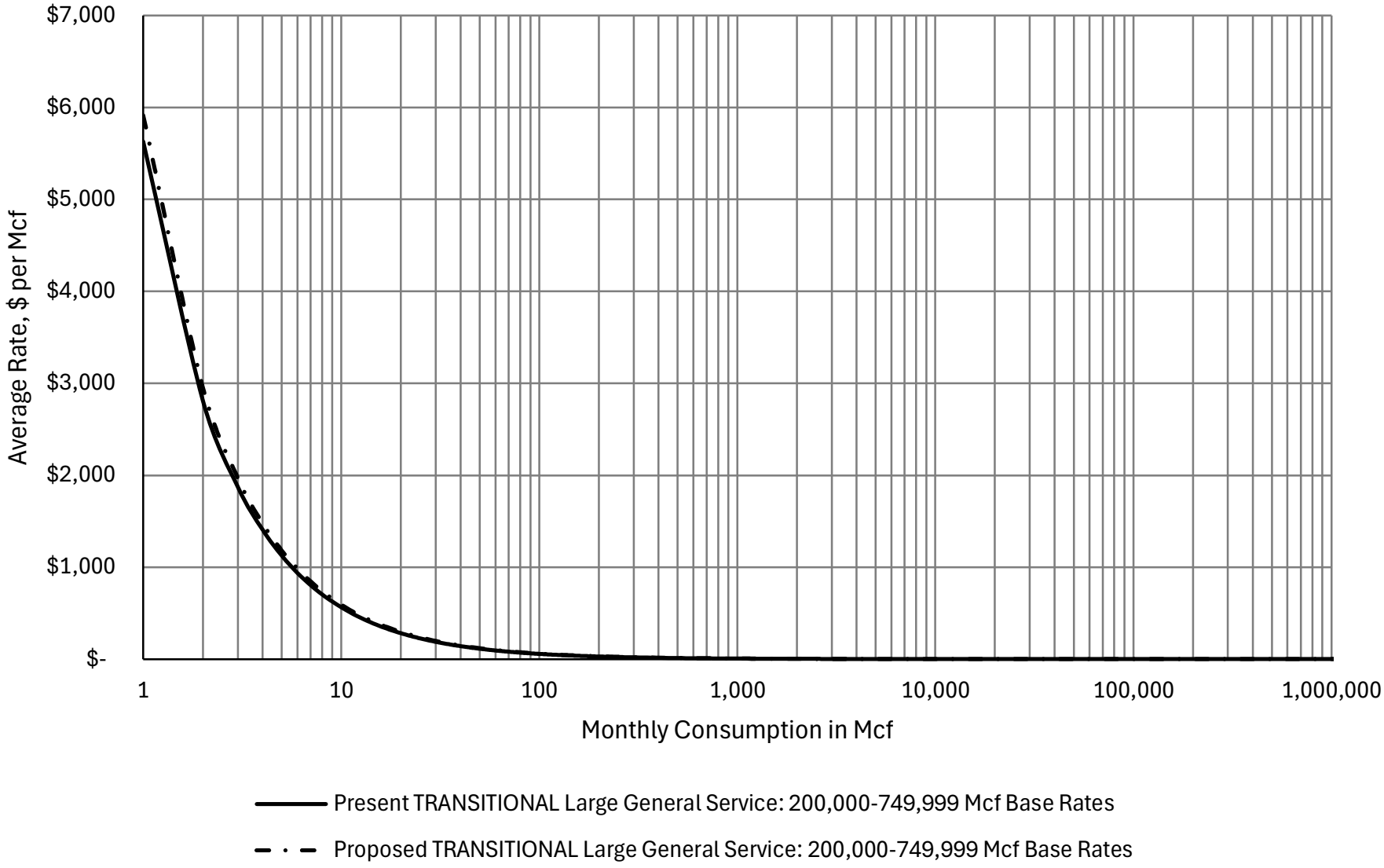
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
Mainline Service: Within 1,000 ft. of Interstate Pipeline



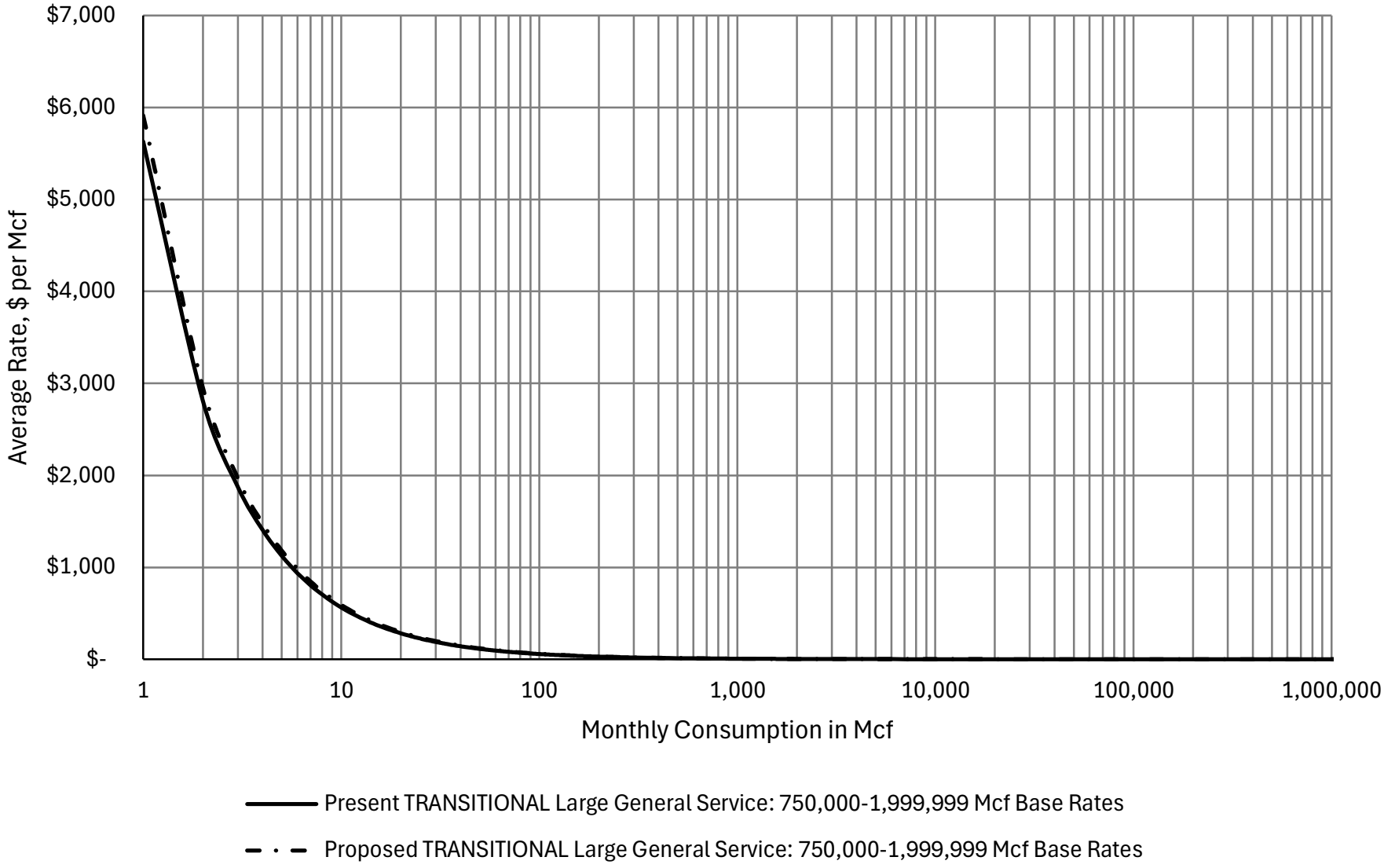
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
TRANSITIONAL Large General Service: 100,000-199,999 Mcf annual consumption



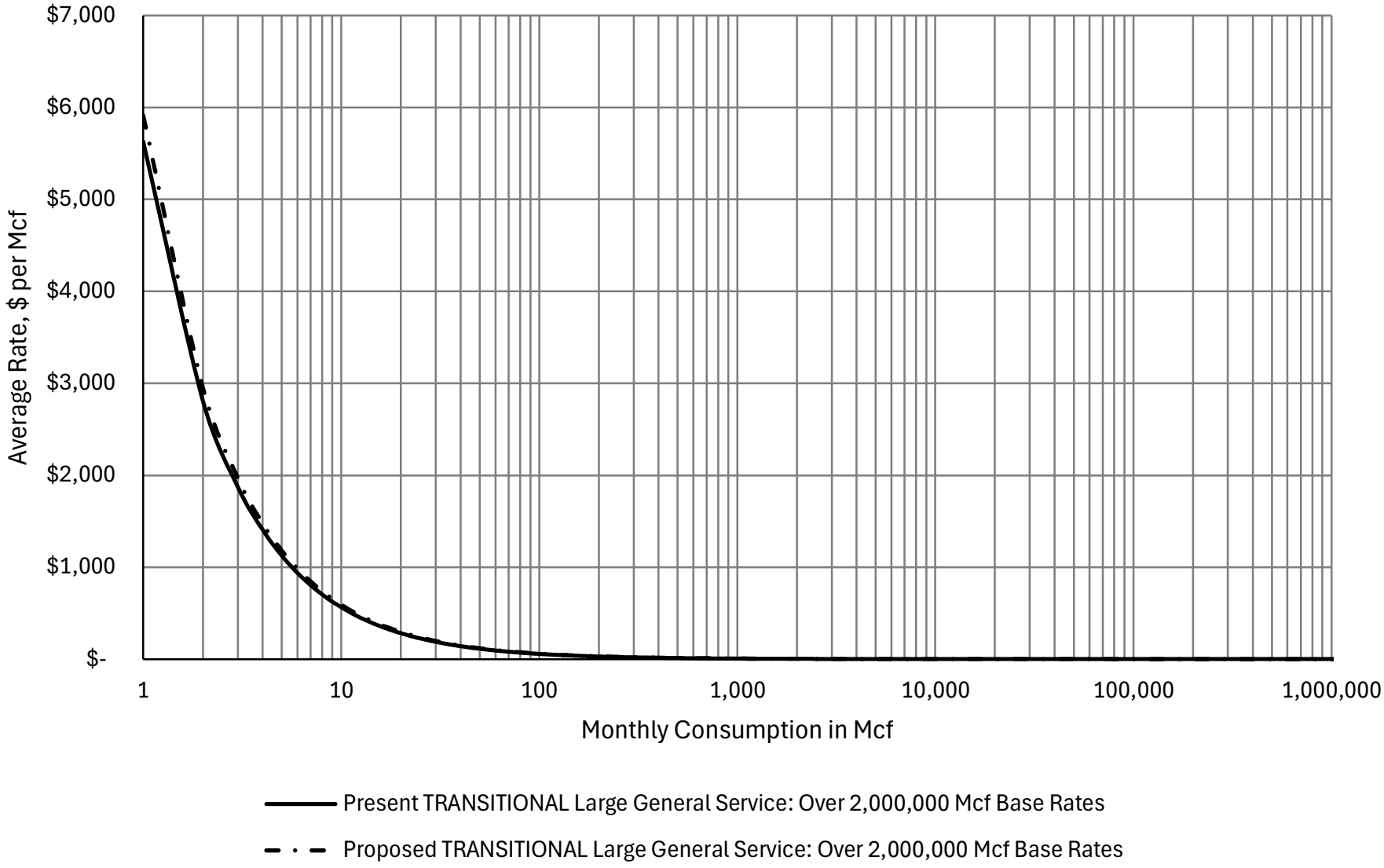
PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
TRANSITIONAL Large General Service: 200,000-749,999 Mcf annual consumption



PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
TRANSITIONAL Large General Service: 750,000-1,999,999 Mcf annual consumption



PEOPLES NATURAL GAS COMPANY LLC
Present and Proposed Base Rates
TRANSITIONAL Large General Service: Over 2,000,000 Mcf annual consumption



#	**Statement of Policy**	**Company's Response**
1	How the ratemaking mechanism and rate design align revenues with cost causation principles as to both fixed and variable costs.	Peoples's WNA is designed to recover distribution revenues needed to satisfy the cost-of-service requirement determined in this proceeding, while mitigating the variance between actual and projected distribution revenues due to weather. The Company recovers a significant portion of fixed costs through volumetric rates. These fixed costs do not vary with the amount of gas delivered to customers and are composed of fixed operation and maintenance expenses, administrative and general expenses, depreciation, certain taxes, a portion of working capital requirements, and return on investment. These costs also do not vary in the short-term with changes in temperature. In the absence of a rate design that affords the Company the opportunity to recover all fixed costs in a fixed monthly charge, the WNA mechanism better aligns distribution revenues with cost causation principles.
2	How the ratemaking mechanism and rate design impact the fixed utility's capacity utilization.	While the WNA mechanism does not directly alter customer usage patterns or system peak demand, it plays an important enabling role in the efficient utilization of the Company's gas distribution capacity. Gas system capacity is designed to meet peak-day requirements driven by weather-sensitive load. Traditional volumetric recovery exposes the Company to revenue volatility when conservation, or efficiency efforts reduce throughput, even though peak-driven infrastructure costs remain largely unchanged.
3	Whether the ratemaking mechanism and rate design reflect the level of demand associated with the customer's anticipated consumption levels.	Customer specific usage factors corresponding to their individual demand is continually updated through the WNA formula and reflects the level of demand associated with the customer's anticipated consumption levels. In this proceeding, the Company is also proposing to set Normal Heating Degree Days using a 65-year regression rather than the average of a 65-year regression and a 20-year average, which more accurately captures recent warming trends. Using a more current weather baseline ensures that the WNA formula better aligns normalized usage with customers' anticipated consumption levels under today's climate conditions.

#	**Statement of Policy**	**Company's Response**
4	How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.	Peoples's WNA is applied on a customer-specific basis and is designed to be revenue-neutral within each customer class, such that it does not create or exacerbate cross-subsidization either within or across classes.
5	How the ratemaking mechanism and rate design limit or eliminate disincentives for the promotion of efficiency programs.	The Company's WNA only addresses variations due to weather and does not affect customers' ability to pursue energy efficiency measures.
6	How the ratemaking mechanism and rate design impact customer incentives to employ efficiency measures and distributed energy resources.	Customers retain strong incentives to reduce usage because the commodity and other charges remain volumetric. The proposed WNA does not eliminate these price signals, so lower usage still results in lower bills.
7	How the ratemaking mechanism and rate design impact low-income customers and support consumer assistance programs.	Under the current WNA mechanism, customers who are currently enrolled to pay their bills based on a percentage of their household income see little to no impact to their bills under the WNA mechanism.
8	How the ratemaking mechanism and rate design impact customer rate stability principles.	The American Gas Association Gas Rate Fundamentals book (Pages 152 – 156) states: "The goal of stability recognizes historical relationships among customers in terms of the proportion of system costs each customer group bears. Stability leads to a policy of gradualism in rate changes if substantial increases (or decreases) are called for in the context of a single rate case. Changes in gas utility pricing policy should be imposed gradually so that customers can adjust and any adverse impacts on the customers' operation are minimized." The WNA mechanism provides customers with more stable annual bills and directly mitigates volatility in their monthly costs. Customers would pay for the costs assigned to the volumetric

#	**Statement of Policy**	**Company's Response**
		base rate in the most recent rate case and customers would not pay more or less than that amount (outside of any established WNA deadband) 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 volumetric base rate.
9	How weather impacts utility revenue under the ratemaking mechanism and rate design.	The Company's WNA adjusts customers' bills due to variations from normal weather during the heating season months of October through May, and it mitigates the revenue effect of weather on the original rate design of the volumetric base rate (outside of any established deadband and limiters). It only applies to Residential and Small/Medium General Service classes and it does not ensure the utility will recover 100% of its authorized distribution revenues, but it does reduce the amount of weather-related variation in both customer bills and associated utility distribution revenues.
10	How the ratemaking mechanism and rate design impact the frequency of rate case filings and affect regulatory lag.	The WNA does not impact the Company's rate case frequency nor does it affect regulatory lag.
11	If or how the ratemaking mechanism and rate design interact with other revenue sources (e.g., surcharges).	The Company's proposed WNA only applies to distribution related charges that are recovering the base distribution revenue requirement from applicable WNA customer classes for the heating season of October through May.
12	Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.	Peoples's WNA includes several consumer protections to ensure fairness and transparency, as follows: a. No Over-Recovery of Revenue: The WNA mechanism operates with a deadband and a limiter. Outside of the deadband and the limiter, the WNA results in an adjusted bill that reflects the revenues that would be recovered under normal weather, i.e., the same normal weather used to set rates. b. No Cross-Subsidization: The WNA is customer-specific.

#	**Statement of Policy**	**Company's Response**
		c. Regulatory Oversight: The WNA is subject to Commission review and regulatory reporting requirements to ensure compliance with approved revenue stabilization objectives and to protect consumers from unintended rate impacts. d. Customer Transparency and Education: Peoples provides clear bill disclosures and customer education regarding WNA adjustments, ensuring consumers understand how the mechanism works and how it impacts their bills.
13	Whether the alternative ratemaking mechanism and rate design are understandable to consumers.	The WNA is not a new concept to the regulated utility industry and similar versions have been successfully implemented by other Pennsylvania natural gas distribution companies. The WNA tariff provides detailed information to the customer of how the mechanism would work and the adjustments are displayed separately on bills and the Company maintains a detailed FAQ related to the WNA on its website, ensuring transparency. Link to Peoples Website → https://www.peoples-gas.com/weather-normalization-adjustment.php
14	How the ratemaking mechanism and rate design will support improvements in utility reliability.	The proposed WNA targets the revenue requirement that would have been already subject to scrutiny and approved by the Commission, meaning that its prudency and reasonableness would have been reviewed and deemed appropriate to support reliability driven initiatives. The proposed WNA helps to minimize the volatility of the recovery of these costs.