BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY - GAS DIVISION

DOCKET NO. R-2026-3060860

VOLUME I OF VI

March 30, 2026

Cover Letter

BRENDAN J. TAYLOR
Vice President
Regulatory Policy & Strategy

PECO
2301 Market Street
S18
Philadelphia, PA 19103

Telephone 215.841.5777
Fax 215.841.6208
www.peco.com
brendan.taylor@exeloncorp.com

March 30, 2026

VIA eFILING

Matthew L. Homsher, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17105-3265

**Re: Pennsylvania Public Utility Commission v.
PECO Energy Company — Gas Division
Docket No. R-2026-3060860**

Dear Secretary Homsher:

Pursuant to Section 1308 of the Pennsylvania Public Utility Code, enclosed for filing on behalf of PECO Energy Company ("PECO" or the "Company") is a Certificate of Service evidencing filing of PECO's Tariff Gas — Pa. P.U.C. No. 8 ("Tariff No. 8"), which has been uploaded to the Secretary's SharePoint site due to its size. Tariff No. 8 sets forth proposed rates designed to produce an increase in the Company's annual distribution revenue of approximately $81 million based on data for a fully projected future test year ending December 31, 2027.

CONTENTS OF THE FILING

Tariff No. 8 contains revisions in, additions to, and deletions from certain Rules and Regulations, rate schedules, and riders in the Company's currently effective tariff. Tariff No. 8 also bears an issue date of March 30, 2026, and an effective date of May 29, 2026.

Along with Tariff No. 8, the Company is filing all the supporting data required by the Pennsylvania Public Utility Commission's ("PUC" or "Commission") regulations at 52 Pa. Code §§ 53.52 — 53.53, including the written direct testimony of thirteen witnesses, who are identified in PECO Statement No. 1, the Direct Testimony of Brendan J. Taylor. A summary of the reasons for the proposed rate increase is set forth in the Company's Statement of Specific Reasons for Proposed Increase in Gas Rates.

An index of the filing is included as Attachment A to this letter.

COUNSEL OF RECORD AND SERVICE ON THE COMPANY

PECO will be represented by the following counsel in this proceeding:

Anthony E. Gay
Adesola K. Adegbesan
Matthew N. Korenoski
PECO Energy Company
2301 Market Street
Philadelphia, PA 19103
267.533.1999 (dir)
215.568.3389 (fax)
anthony.gay@exeloncorp.com
adesola.adegbesan@exeloncorp.com
matthew.korenoski@exeloncorp.com

Kenneth M. Kulak
Mark A. Lazaroff
Brooke E. McGlinn
Catherine G. Vasudevan
Morgan, Lewis & Bockius LLP
2222 Market Street
Philadelphia, PA 19103
215.963.5384 (dir)
215.953.5001 (fax)
ken.kulak@morganlewis.com
mark.lazaroff@morganlewis.com
brooke.mcglinn@morganlewis.com
catherine.vasudevan@morganlewis.com

PECO's attorneys are authorized to accept service on behalf of the Company in this proceeding. PECO requests that the Commission and all parties electronically serve copies of all documents in this proceeding on its attorneys.

USE OF ALTERNATIVE METHOD OF CUSTOMER NOTIFICATION

PECO hereby advises the Commission that it has elected to use the alternative method of customer notification set forth in the Commission's regulations at 52 Pa. Code § 53.45(b)(4). Consequently, as required by that regulation, PECO will notify its customers of the proposed rate increase through bill inserts along with paid advertisements in major local newspapers. PECO also agrees to extend from 60 to 90 days the minimum period within which the filing of a complaint places the burden of proof upon the Company with respect to proposed rates, pursuant to 52 Pa. Code § 53.45(b)(4)(vi).[1]

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[1] In addition, PECO is posting the filing to its website, https://www.peco.com/mv-account/my-dashboarcVrates-tariffs/filings, and issuing a news release describing the proposed changes to local newspapers and to local radio and television stations, pursuant to 52 Pa. Code § 53.45(b)(2)-(3).

REQUEST FOR CONFIDENTIAL TREATMENT OF PROPRIETARY INFORMATION

Certain Company responses to Commission filing requirements contain information that PECO considers to be proprietary and confidential. These materials have been marked ***Confidential*** and are being included in separate electronic files submitted to the Secretary's SharePoint site.

PECO requests that the copies of the materials that have been marked ***Confidential*** be treated confidentially by the Commission, including its various Offices and Bureaus. In particular, the Company requests that the ***Confidential*** material be excluded from the Commission's public document folder and not be disclosed to the public. PECO intends to request the entry of an appropriate Protective Order from the presiding Administrative Law Judge(s) to maintain the confidentiality of such material if it is to be provided to parties in this case.

CERTIFICATE OF SERVICE

As indicated on the attached Certificate of Service, the Company has served copies of this filing on the Commission's Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate. The Company is also providing courtesy copies of the filing to the Law Bureau (David E. Screven, Chief Counsel).

Respectfully submitted,

Brendan J. Taylor
Vice President
Regulatory Policy and Strategy

Enclosures

c: Certificate of Service (w/encls.)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2026-3060860**
	:	
PECO ENERGY COMPANY – GAS DIVISION	:	

CERTIFICATE OF SERVICE

I hereby certify and affirm that I have this day served a copy of the **PECO Energy Company's General Base Rate Filing for Gas Operations** on the following persons in the manner specified in accordance with the requirements of 52 Pa. Code § 1.54:

VIA OVERNIGHT MAIL

Darryl A. Lawrence
Office of Consumer Advocate
Forum Place, 5th Floor
555 Walnut Street
Philadelphia, PA 17101-1923
ra-oca@paoca.org
Counsel for Office of Consumer Advocate

NazAarah Sabree
Small Business Advocate
Office of Small Business Advocate
Forum Place
555 Walnut Street, 1st Floor
Harrisburg, PA 17101
ra-sba@pa.gov
Counsel for Office of Small Business Advocate

Allison Kaster
Bureau of Investigation & Enforcement
Pennsylvania Public Utility Commission
Commerce Keystone Building
400 North Street, 2nd Floor
Harrisburg, PA 17105-3265
akaster@pa.gov
Counsel for Bureau of Investigation & Enforcement

David Screven
Chief Counsel
Pennsylvania Public Utility Commission
Law Bureau
400 North Street, 3 West
Harrisburg, PA 17120
dscreven@pa.gov

Kenneth M. Kulak (Pa. No. 75509)
Mark A. Lazaroff (Pa. No. 315407)
Catherine G. Vasudevan (Pa. No. 210254)
Brooke E. McGlinn (Pa. No. 204918)
Morgan, Lewis & Bockius LLP
2222 Market Street
Philadelphia, PA 19103-3007
215.963.5384 (bus)
215.963.5001 (fax)
ken.kulak@morganlewis.com
mark.lazaroff@morganlewis.com
catherine.vasudevan@morganlewis.com
brooke.mcglinn@morganlewis.com

Dated: March 30, 2026

Counsel for PECO Energy Company

DB1/ 167555458.1

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- **PECO Exhibit MH-3: Estimated Annual Depreciation Accruals Related to Utility Plant in Service for 2027**
- **PECO Exhibit MH-4: 2023 Depreciation Study**

PECO Statement No. 8: Direct Testimony of Ann E. Bulkley

- **PECO Exhibit AEB-1 through AEB-13**

PECO Statement No. 9: Jiang Ding

- **PECO Exhibit JD-1: Results Summary and Allocation by Rate Class**
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Statement of Specific Reasons

PECO ENERGY COMPANY

STATEMENT OF SPECIFIC REASONS
FOR PROPOSED INCREASE IN GAS RATES

I. Introduction

PECO Energy Company ("PECO" or the "Company") is requesting an overall natural gas rate increase of approximately $81 million per year. In accordance with Section 1308 of the Public Utility Code, the tariff setting forth the Company's proposed rates bears an effective date of May 29, 2026. However, the Company anticipates that its requested increase will be suspended and investigated by the Pennsylvania Public Utility Commission (the "PUC" or the "Commission") and, therefore, the Company does not expect that new Commission-approved rates will become effective until approximately January 1, 2027.

PECO last filed for a rate increase in 2024. The principal reasons for the Company's proposed rate increase are to: (A) permit PECO to earn a fair return on the substantial investments used and useful in the Company's provision of safe and reliable gas service to customers; (B) support additional investments in utility infrastructure in accordance with the Company's Commission-approved infrastructure replacement program; (C) deploy new information technology to meet PECO's customers' expectations and drive operational improvements and efficiencies; and (D) recover higher operating expenses necessary to provide gas utility service, including increased costs of labor, contracting, and materials.

II. Reasons for the Requested Rate Increase

A. Fair return on the substantial investments used to provide safe and reliable service to customers

PECO's gas operations include approximately 7,350 miles of gas mains, approximately 484,300 gas services, 28 gate stations, and liquefied natural gas ("LNG") and propane-air peaking plants. It takes considerable expertise and significant capital investment and operations and maintenance ("O&M") activities to provide PECO's customers with safe and reliable service, and to ensure customers receive the level of service they expect. PECO continuously strives to improve its system reliability, customer service, and offerings to meet evolving customer expectations and needs.

Since rates were established in PECO's last rate case in 2024,[1] PECO has continued to make substantial investments in new and replacement utility plant to ensure that customers can continue to receive the safe and reliable service they have come to expect. Between January 1, 2026, and December 31, 2027 (the end of the fully projected future test year ("FPFTY") in this filing, PECO will have invested $790.9 million in additional gas distribution plant.

Absent a rate increase, the Company's overall rate of return at present rates is projected to be only 6.60% for the FPFTY, as shown in Schedule A-1 of PECO Exhibit MJT-1, the direct testimony of Michael J. Trzaska (PECO Statement No. 4). More importantly, the indicated return on common equity under present rates is anticipated to be only 8.18%, which is inadequate by any reasonable standard and far less than required to provide the Company with a reasonable opportunity to attract capital.

Without the requested rate relief, PECO's financial results would deteriorate even further in 2027 and thereafter. This would jeopardize the Company's ability to appropriately invest in the infrastructure needed to maintain and improve its safety, reliability, and customer-service levels. A lack of rate relief would also have an adverse impact on PECO's credit-coverage ratios and negative implications with respect to maintaining the Company's current credit ratings, which would increase the Company's financing costs and, ultimately, costs to customers.

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1 *PECO Energy Company General Base Rate Filing for Gas Operations*, Docket No. R-2024-3046932 (filed Mar. 27, 2024).

B. Support for Commission-approved infrastructure replacement

Many of the Company's capital investments are made in coordination with the goals and requirements of PECO's Second Gas Long-Term Infrastructure Improvement Plan ("LTIIP II"), which the Commission approved on December 8, 2022. In that proceeding, the Commission approved PECO's plans to spend $1 billion to continue PECO's accelerated replacement programs for the retirement of aging mains, services, and district regulator stations. By aligning the Company's planned capital investments through the FPFTY and the Company's planned LTIIP expenditures, the Company can improve reliability and replace aging infrastructure more efficiently and at lower overall cost to customers.

C. Deployment of new information technology for system modernization, security, and customer service

PECO is making significant capital investments in information technology to drive operational improvements and efficiencies, reduce risk, and increase reliability. The Company is investing in upgrades to its gas supervisory control and data acquisition system. Additionally, PECO recently completed upgrades to its LNG plant control system to increase cybersecurity defenses in the ever-evolving threat landscape. Finally, a primary area of PECO's capital investment relating to customer operations covers the design, development, implementation, lifecycle upgrades and replacements, and security of customer-facing systems, as well as the development and implementation of web tools, such as outage tools and mobile app technologies, so customers can easily access PECO customer systems and information through multiple channels. These individual projects help the Company create and improve the technology PECO customers use to access account and outage information; enroll in assistance programs; make start, stop, and move requests; receive usage data, and receive and pay bills.

D. Increased costs to provide public service

Continued investment in PECO's natural gas distribution system is needed to serve customers, but the cost of doing so has increased significantly. Sustained inflationary pressure has contributed to elevated interest rates, which have raised the cost of investment and led to increases in the Company's labor, contracting, and materials expense.

The Company has successfully mitigated the impact of the foregoing costs to the extent possible. Notably, PECO projects that its 2027 O&M expenses, excluding pension and bad debt expense (which are variable year to year and largely outside the Company's control), will decrease from the end of 2025 at an annual rate of 1.3% compared against the 2.6% projected average inflation rate in 2026 and 2027. The Company's ongoing initiatives to increase efficiency and minimize costs to its gas business have resulted in savings for customers.

III. Management Performance

As set forth in the testimony accompanying this rate case filing, PECO has demonstrated superior management performance. The Company's efforts and accomplishments include:

Quality and Reliability of Service

- Replacing outmoded (i.e., cast iron and unprotected bare steel) mains on an accelerated basis in coordination with the Company's LTIIP with a 21% reduction in incoming leaks since 2019.
- Achieving top-decile performance in odor response rate among similar gas utilities per industry benchmarking. Additionally, gas odor calls have decreased 36% since 2014.
- Implementing a new One Call ticket management system that provides timely notification to contractors of critical PECO assets within the scope of their work site, resulting in a 13% reduction in incidents resulting in damages to PECO's distribution system from 399 in 2024 to 349 in 2025.

Energy Efficiency and Customer Energy Savings

- Continuing PECO's Safe and Efficient Heating Program, which provides qualifying low-income customers no-cost direct installation measures through the

Low-Income Usage Reduction Program and as part of free home energy assessments to improve the efficiency and safety of natural gas heating in customers' homes.

- Offering residential customers a mix of rebates to encourage upgrades to high-efficiency furnaces, boilers and water heaters, and direct install measures, and to receive discounts on smart thermostats purchased through PECO's online marketplace.

Customer Service

- Implementing an "Assistance Finder" feature, which has provided personalized recommendations and application instructions to nearly 30,000 customers for programs such as payment arrangements, budget billing, and customer assistance programs.

- Increasing enrollment of customers in PECO's "MyAccounts" on-line system, by 10% since the end of 2023 with associated reductions in PECO's customer operations costs.

- Offering a multi-factor authentication process to improve customer account security and increasing online notifications to customers, including educational campaigns about payment scams.

- Implementing a Service Installations and Upgrade Portal that makes it easier for customers to request new or upgraded service online.

- Introducing a Planned Outage Notification System that provides personalized notifications to customers about what to expect during the outage and proactive alerts if work is cancelled or rescheduled.

Employee Safety

- Continuously improving performance and fostering a safety culture that engages the entire workforce to prevent accidents, injuries, and occupational illnesses.

- Regularly reviewing and enhancing policies and procedures consistent with best practices and recommendations under the Pipeline Safety Management System.

Environmental Achievements

- Continuing to reduce greenhouse gas emissions from Company operations, with a reduction of 59% from 2015 through 2025.

Promoting PECO's Communities and Diversity as well as Economic and Workforce Development

- Investing more than $38 million through corporate donations and employee giving campaigns (with corporate matching gifts) in hundreds of local and regional non-profit programs, organizations and institutions in Southeastern Pennsylvania, which provide access to arts and culture, and support STEM education, the environment and green spaces, community vitality, workforce development, and reduction of gun violence.

- In 2025, launching the Customer Relief Fund, a $10 million initiative designed to provide immediate bill assistance to limited and moderate-income households experiencing rising energy costs, and in 2026, adding an additional $2.5 million to further strengthen support to customers with the greatest need.

- Supporting PECO employees in volunteering nearly 26,140 hours of service across 393 nonprofit organizations.

- Along with other Exelon operating companies and the Exelon Foundation, creating a $36 million Community Equity Capital Fund to begin establishing access to capital for small businesses from under-resourced communities so that they can create more jobs, grow their companies, and reinvest in their neighborhoods and communities.

IV. Supporting Data

PECO is filing all the supporting data required by the Commission's regulations, including data for the historic test year ("HTY") ended December 31, 2025; the future test year ending December 31, 2026; and the FPFTY ending December 31, 2027. Because the Company is basing its claim principally on the level of operations for the FPFTY, the discussion that follows will address FPFTY data.

Rate Base. PECO's measures of value reflect the Company's balances of gas plant on December 31, 2027, including common plant used in, and appropriately allocated to, gas operations, as shown in Schedule C of PECO Exhibit MJT-1. The estimated original cost of gross plant on December 31, 2027, was developed by adding the estimated plant additions by account for 2026 and 2027 and subtracting the estimated plant retirements for 2026 and 2027 from the estimated original cost of gross plant as of December 31, 2025. The estimated accumulated book reserve on December 31, 2027, was calculated in similar fashion. Specifically, the December 31, 2027 estimated accumulated depreciation was developed by: (1) adding the 2026 and 2027 estimated annual depreciation accruals to the actual accumulated depreciation by account as of January 1, 2026; (2) subtracting the estimated 2026 and 2027 plant retirements by account; and (3) adding 2026 and 2027 estimated salvage and subtracting estimated removal costs that are closed to the book reserve, by account. The depreciated original cost of utility plant in service, cash working capital, pension asset, materials and supplies, and gas storage inventory were included in the determination of the measures of value, while accumulated deferred Federal income taxes, a 13-month average of customer advances, and a 13-month average of customer deposits were deducted from measures of value.

Operating Revenue and Expenses. The revenue and expense claims for the FPFTY have been prepared in accordance with accepted practices of the Commission. Operating revenues at present rates were derived from budgeted revenues for PECO's gas operations for the 12 months ending December 31, 2027, and adjusted in the manner summarized on Schedule D-5 of PECO Exhibit MJT-1. Principal revenue adjustments include annualizing revenues for changes in the number of customers and the discounts provided to customers in PECO's Customer Assistance Plan, using a 10-year period to define normal weather for base-rate sales and billing determinants, and increasing revenue to reflect a normalized annual service period containing 365.25 days.

Pro forma FPFTY operating expenses were developed from PECO's budget for gas operations for the 12 months ending December 31, 2027. Budgeted expenses were prepared based on the business activities and related cost categories of PECO's gas division (e.g., payroll, pensions, employee benefits, outside contracting costs). The expenses were distributed to the accounts identified in the Federal Energy Regulatory Commission ("FERC") Uniform System of

Accounts for Natural Gas Companies based on the expense distribution experienced by the Company during the HTY. The budget data, as distributed to FERC accounts, were annualized and/or normalized in accordance with established Commission ratemaking practices, and other appropriate adjustments were made, all of which are set forth in Schedule D of PECO Exhibit MJT-1. The necessary adjustments were made to the appropriate FERC accounts.

Annual depreciation expense for gas and common plant in service on December 31, 2027, was calculated using the remaining life method, which the Commission has previously approved for PECO's gas operations. PECO's claim for the estimated annualized depreciation accrual associated with gas plant in service on December 31, 2027, is set forth in Schedule D-17 of PECO Exhibit MJT-1 and is described by Mr. Trzaska in PECO Statement No. 4. The manner in which PECO developed its claimed annual accrual is described in the direct testimony of Ms. Mariana Hufford (PECO Statement No. 7).

Income Taxes. Income taxes were calculated using procedures commonly accepted by the Commission. The interest expense deduction was synchronized with the Company's measures of value and claimed weighted-average cost of long-term debt. The normalization method was used to reflect the tax-book timing differences associated with the use of accelerated methods of tax depreciation to the extent permitted by the Commission and legal precedent. In addition, there are adjustments to other tax-book differences and flow-through amounts. The income tax expense claims for the FPFTY at present rate and proposed rate revenue levels are shown on PECO Exhibit MJT-1, Schedule D-18.

As is evident from the foregoing and the extensive supporting data filed by the Company, the proposed increase is just and reasonable and is the minimum increase necessary to enable the

Company to earn a reasonable return on the fair value of its property that is used and useful in the public service, to maintain the integrity of its existing capital, and to attract new capital.

V. Rate Structure and Rate Design

As Mr. Joseph A. Bisti (PECO Statement No. 10) explains in his direct testimony, in developing its rate-structure proposal, the Company considered the results of a cost-of-service study performed by Ms. Jiang Ding (PECO Statement No. 9) in her direct testimony. While the cost-of-service study was used as a guide, the Company also considered principle of gradualism that has traditionally been applied in Pennsylvania. Accordingly, the proposed rates were designed to mitigate the impact on each major rate class, to the extent practicable, while still making meaningful movement toward the system average rate of return.

PECO proposes certain changes in rate design, which include principally aligning fixed distribution/customer charges with, or closer to, customer-classified costs. Certain other changes in rate design and in the rules, regulations, and riders set forth in the Company's tariff are described in the direct testimony of Mr. Bisti and the direct testimony of Ms. Megan A. McDevitt (PECO Statement No. 11).

VI. Weather Normalization Adjustment

As part of its rate filing, the Company also proposes a Weather Normalization Adjustment ("WNA") mechanism. The WNA mechanism is an alternative rate design mechanism designed to provide customers with predictability in billing, better enabling customers to budget and pay their bills, mitigate the impact of higher bills during severely cold months, such as the 2025 to 2026 winter, and provide PECO with greater certainty in its ability to earn the projected distribution revenues authorized by the Commission when setting rates.

VII. **Conclusion**

The requested increase in revenues is the minimum necessary to enable the Company to appropriately invest in the infrastructure needed to maintain and improve its safety, reliability, and customer-service levels; to maintain the integrity of PECO's existing capital; to attract additional capital at reasonable costs; and to have an opportunity to achieve a fair rate of return on the Company's investment in property dedicated to public service. The Company's proposed revenue allocation and rate design are just, reasonable, and non-discriminatory. Accordingly, the Company's proposed rates, rules, and terms of service should be permitted to become effective as filed.

Plain Language Statement of Reasons

PLAIN LANGUAGE STATEMENT OF REASONS FOR PECO ENERGY COMPANY'S REQUEST TO INCREASE GAS RATES

PECO Energy Company ("PECO" or the "Company") has asked the Pennsylvania Public Utility Commission (the "PUC" or the "Commission") for an annual overall natural gas rate increase of approximately $81 million per year. Although the new rates are proposed to become effective on May 29, 2026, the Company expects that they will be suspended for investigation by the PUC until approximately January 1, 2027.

The main reasons PECO is asking for an increase in rates are:

- Between January 1, 2026, and December 31, 2027 (the end of the fully projected future test year in this case), PECO will have invested $790.9 million in additional gas distribution plant to ensure that customers can continue to receive safe and reliable gas service.
- Continued investment in PECO's gas distribution system is needed to serve customers, but the cost of doing so has increased significantly. PECO last filed for an increase in gas base rates in 2024. During the last two years, inflation and interest rates have remained elevated, raising the cost of investment and increasing the Company's labor, contracting, and materials expense. The Company has actively worked to mitigate the impact of these increased costs to keep rates affordable, resulting in savings for customers.
- Without the requested rate relief, the Company's financial results would deteriorate in 2027 and thereafter. This would jeopardize the Company's ability to appropriately invest in the infrastructure needed to maintain and improve safety, reliability, and customer service levels. A lack of rate relief would also have a negative effect on PECO's ability to maintain its current credit ratings, which would increase its financing costs and, ultimately, costs to customers.

PECO is filing all the supporting data required by the PUC's regulations, as well as the written statements of 13 witnesses and numerous exhibits. All the data and other information supporting PECO's rate increase have been prepared in ways that the PUC has approved in the past for PECO and other utilities. The filing also includes a request for approval of a Weather Normalization Adjustment ("WNA") mechanism. The WNA is an alternative rate design mechanism proposed in accordance with 66 Pa. C.S. § 1330. The WNA would adjust certain customers' bills to reflect normalized weather conditions and is designed to provide customers with predictability in billing, better enabling customers to budget and pay their bills; mitigate the impact of higher bills during severely cold months, such as the 2025 to 2026 winter, as well as provide PECO with greater certainty in its ability to earn the projected distribution revenues authorized by the Commission when setting rates.

In summary, the proposed increase in revenues is the minimum necessary to enable the Company to appropriately invest in the infrastructure needed to maintain and improve safety, reliability, and customer service levels.

Section 53.52 Filing Requirements

Q. 53.52.a-Gas

Whenever a public utility, other than a canal, turnpike, tunnel, bridge or wharf company files a tariff, revision or supplement effecting changes in the terms and conditions of service rendered or to be rendered, it shall submit to the Commission, with the tariff, revision or supplement, statements showing all of the following:

1. The specific reason for each change.
2. The total number of customers served by the utility.
3. A calculation of the number of customers, by tariff subdivision, whose bills will be affected by the change.
4. The effect of the change on the utility's customers.
5. The direct or indirect effect of the proposed change on the utility's revenue and expenses.
6. The effect of the change on the service rendered by the utility.
7. A list of factors considered by the utility in its determination to make the change. The list shall include a comprehensive statement as to why these factors were chosen and the relative importance of each. This subsection does not apply to a portion of the tariff change seeking a general rate increase as defined in 66 Pa. C.S. § 1308 (relating to voluntary changes in rates).
8. Studies undertaken by the utility in order to draft its proposed change. This paragraph does not apply to a portion of tariff change seeking a general rate increase defined in 66 Pa. C.S. § 1308.
9. Customer polls taken and other documents, which indicate customer acceptance and desire for the proposed change. If the poll or other documents reveal discernible public opposition, an explanation of why the change is in the public interest shall be provided.
10. Plans the utility has for introducing or implementing the changes with respect to its ratepayers.
11. F.C.C., FERC or Commission orders or rulings applicable to the filing.

A. 53.52.a-Gas

(a)(1) The specific reason for each change.

The specific reasons for the rate increase are summarized in the Company's Statement of Specific Reasons, which is included as part of the Company's filing.

(a)(2) The total number of customers served by the utility.

The total number of customers on PECO's system as of December 31, 2025, is 556,281.

(a)(3) A calculation of the number of customers, by tariff subdivision, whose bills will be affected by the change.

All customers as of December 31, 2025, in the following tariff subdivisions will be affected by the proposed change, as follows:

Tariff Rate	Customers
GR	510,959
GC	44,660
L	6
IS	1
MV-F	15
MV-I	1
OL	2
TCS	20
TS-F	410
TS-I	207

(a)(4) The effect of the change on the utility's customers.

Refer to PECO Statement No. 10, the Direct Testimony of Joseph A. Bisti and accompanying exhibits.

(a)(5) The effect, whether direct or indirect, of the proposed change on the utility's revenue and expenses.

The proposed changes will increase total revenues to reflect the Company's revenue requirement, including increases in the Company's expenses. For details on specific changes, see the Direct Testimony of Michael J. Trzaska, PECO Statement No. 4 and accompanying exhibits.

(a)(6) The effect of the change on the service rendered by the utility.

No changes are expected in the service rendered by the Company. The proposed change will enable the Company to recover its costs and earn a fair return on its investment in used and useful property and, in that way, will facilitate the Company's on-going efforts to maintain and enhance its levels of safety, reliability and customer service.

(a)(7) A list of factors considered by the utility in its determination to make the change. The list shall include a comprehensive statement as to why these factors were chosen and the relative importance of each. This subsection does not apply to a portion of the tariff change seeking a general rate increase as defined in 66 Pa.C.S. Section 1308 (relating to voluntary changes in rates).

The changes being made to rate design are discussed in the Direct Testimony of Joseph A. Bisti, PECO Statement No. 10. Further, PECO Statement No. 11, the Direct Testimony of Megan A. McDevitt, discusses changes to Rules and Regulations, Rate Schedules, Section 1307 surcharge mechanisms, and miscellaneous revisions that are set forth in the proposed tariff.

(a)(8) Studies undertaken by the utility in order to draft its proposed change. This paragraph does not apply to a portion of tariff change seeking a general rate increase defined in Pa.C.S. Section 1308.

No studies were undertaken.

(a)(9) Customer polls taken and other documents, which indicate customer acceptance and desire for the proposed change.

No customer polls were conducted.

(a)(10) Plans the utility has for introducing or implementing the changes with respect to its customers.

The Company plans to implement the changes upon approval by the Commission. The methods of notification to the customers will include a press release, paid advertisements in major local newspapers and a bill insert.

(a)(11) F.C.C., or FERC or Commission orders or rulings applicable to the filings.

No FCC, FERC or Commission orders or rulings are directly applicable. To the extent that any FCC, FERC or Commission order or ruling may be relevant, it is discussed in the direct testimony submitted as part of the Company's filing.

Q. 53.52.b-Gas

Whenever a public utility other than a canal, turnpike, tunnel, bridge or wharf company files a tariff, revision or supplement which will increase or decrease the bills to its customers, it shall submit in addition to the requirements of subsection (a), to the Commission, with the tariff, revision or supplement, statements showing the following:

1. The specific reasons for each increase or decrease.
2. The operating income statement of the utility for a 12-month period, the end of which may not be more than 120 days prior to the filing.
3. A calculation of the number of customers, by tariff subdivision, whose bills will be increased.
4. A calculation of the total increases, in dollars, by tariff subdivision, projected to an annual basis.
5. A calculation of the number of customers, by tariff subdivision, whose bills will be decreased.
6. A calculation of the total decreases, in dollars, by tariff subdivision, projected to an annual basis.

A. 53.52.b-Gas

(b) (1) Specific reasons for each change.

Refer to the Company's Statement of Specific Reasons included with this filing.

(b) (2) Utility's operating income statement ending not more than 120 days prior to filing date - historic year.

Refer to PECO Statement No. 4, Exhibit MJT-3, Schedules B-2 to B-5.

(b) (3) Number of customers, by tariff subdivision, whose bills will be increased.

Refer to response to 53.52 (a)(3) for the number of customers whose bills will be increased.

(b)(4) Total increases, in dollars, by tariff subdivision, projected to an annual basis.

Refer to PECO Statement No. 10, Exhibits JAB-1 and JAB-4, for the requested information.

(b)(5) Number of customers, by tariff subdivision, whose bills will be decreased.

None.

(b) (6) Total decreases, in dollars, by tariff subdivision, projected to an annual basis.

None.

Q. 53.52.c-Gas

If a public utility files a tariff, revision or supplement which it is calculated will increase the bills of a customer or a group of customers by an amount, when projected on an annual basis, exceeding 3% of the operating revenues of the utility - subsection (b)(4) divided by the operating revenues of the utility for a 12-month period as defined in subsection (b)(2) - or which it is calculated will increase the bills of 5% or more of the number of customers served by the utility - subsection (b)(3) divided by subsection (a)(2) - it shall submit to the Commission with the tariff, revision or supplement, in addition to the statements required by subsections (a) and (b), all of the following information:

1. Rate of return for historic year and anticipated for future year.
2. A detailed balance sheet of the utility as of the close of the historic year.
3. A summary, by detailed plant accounts, of book value of the property of the utility at the end of historic year.
4. A statement showing the amount of depreciation reserve applicable to each detailed plant account.
5. A statement of operating income, setting forth the operating revenues and expenses by detailed accounts - historic year.
6. A description of any major change in the operating or financial condition of the utility occurring between the date of the balance sheet at the end of the historic year and filing date.

A. 53.52.c-Gas

(c)(1) Rate of return for historic year and anticipated for future year.
Refer to PECO Statement No. 4, Direct Testimony of Michael Trzaska, Exhibits MJT-1, MJT-2 and MJT-3, Schedule A-1.

(c)(2) Detailed balance sheet at the end of the historic year.

Refer to PECO Statement No. 4, Exhibit MJT-3, Schedule B-1.

(c)(3) Summary, by detailed plant accounts, of book value of property of utility at end of historic year.

Refer to PECO Statement No. 4, Direct Testimony of Michael Trzaska, Exhibit MJT-3, Schedule C-2.

(c)(4) Respective amount of the depreciation reserve applicable to each detailed plant account.

Refer to PECO Statement No. 4, Direct Testimony of Michael Trzaska, Exhibits MJT-1, MJT-2 and MJT-3, Schedule C-3.

(c)(5) Statement of operating income, setting forth the operating revenues and expenses by detailed accounts - historic year.

Refer to PECO Statement No. 4, Direct Testimony of Michael Trzaska, Exhibit MJT-3, Schedules B-2 to B-5.

(c)(6) Description of any major change in the operating or financial condition of utility occurring between the date of the balance sheet at end of the historic year and filing date.

There have been no major changes since the date of the balance sheet. In addition, please refer to PECO Statement No. 3, the Direct Testimony of Marissa E. Humphrey, for a discussion of the Company's financial condition.

Customer Notice

peco[SM]
AN EXELON COMPANY

NOTICE OF PROPOSED NATURAL GAS RATE CHANGES

To Our Customers:

PECO Energy Company ("PECO" or the "Company") is filing a request with the Pennsylvania Public Utility Commission (the "PUC") to increase natural gas distribution rates as of May 29, 2026. This notice describes the Company's natural gas rate request, the PUC's role, and what actions you can take.

PECO has requested an annual overall natural gas distribution rate increase of approximately $81 million. The filing also includes a request for approval of a Weather Normalization Adjustment ("WNA") as an alternative rate mechanism in accordance with 66 Pa. C.S. § 1330. The WNA would adjust certain customers' bills to reflect normalized weather conditions.

If the Company's entire request is approved:

- The total monthly bill for a residential customer using 80 Ccf of natural gas (one Ccf equals one hundred cubic feet) would increase by $14.52 from $127.14 to $141.66 or by 11.4%.
- The total monthly bill for a commercial customer using 400 Ccf that receives service through one small diaphragm meter would increase by $33.72 from $521.20 to $554.92 or by 6.5%. The total monthly bill for a commercial customer that receives service through one larger meter OR through more than one meter would increase by $50.81 from $532.45 to $583.26, or 9.5%.
- The total monthly bill for an industrial customer using 36,000 Ccf would increase by $4,418.17 from $44,788.08 to $49,206.25 or by 9.9%.

To find out your customer class or how the requested increase may affect your natural gas bill, contact PECO at **1-800-494-4000**. The rates requested by the Company may be found in Gas Service Tariff No. 7. You may examine the material filed with the PUC, which explains the requested increase and the reasons for it. A copy of this material is kept at PECO's office. Upon request, the Company will send you the Statement of Reasons for the Company's Request to Increase Gas Rates, explaining why the Company requested the rate increase. A copy can also be reviewed by visiting **https://www.peco.com/my-account/my-dashboard/rates-tariffs/filings**

(Over)

The state agency that approves natural gas rates for public utilities is the PUC. The PUC will examine the requested natural gas rate increase and can prevent existing rates from changing until it investigates and/or holds hearings on the request. The Company must prove that the requested natural gas rates are reasonable. After examining the evidence, the PUC may grant all, some, or none of the request or may reduce existing rates. The PUC may change the amount of the natural gas rate increase or decrease requested by the utility for each customer class. As a result, the natural gas rate charged to you may be different than the rate requested by the Company and shown above.

There are three ways to challenge a Company's request to change its rates:

1. You can file a formal complaint. If you want a hearing before a judge, you must file a formal complaint. By filing a formal complaint, you assure yourself the opportunity to take part in hearings about the natural gas rate increase request. All complaints should be filed with the PUC before May 29, 2026. If no formal complaints are filed, the Commission may grant all, some or none of the request without holding a hearing before a judge.

2. You can send the PUC a letter with information on why you object to the requested natural gas rate increase. Sometimes there is information in these letters that makes the PUC aware of problems with the Company's service or management. This information can be helpful when the PUC investigates the rate request.

Send your letter or request for a formal complaint form to the Pennsylvania Public Utility Commission, Post Office Box 3265, Harrisburg, PA 17105-3265.

3. You can be a witness at a public input hearing. Public input hearings are held if the Commission opens an investigation of the Company's natural gas rate increase request and if there is a large number of customers interested in the case. At these hearings, you have the opportunity to present your views to the PUC judge hearing the case and the Company representatives. All testimony given "under oath" becomes part of the official rate case record. These hearings are held in the service area of the Company but may be held virtually.

For more information, call the PUC at **1-800-692-7380**. You may leave your name and address so you can be notified of any public input hearings that may be scheduled in this case.

PECO Verification

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060860**
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Brendan J. Taylor, hereby declare that I am the Vice President of Regulatory Policy and Strategy of PECO Energy Company; that as such, I am authorized to make this verification on its behalf; that the facts set forth in the foregoing tariff filing are true to the best of my knowledge, information and belief, and that I make this verification subject to the penalties of 18 Pa. C.S. § 4904 pertaining to false statements to authorities.

Dated: March 30, 2026

____
Brendan J. Taylor

PECO Exhibit 1:
PECO Gas Tariff No. 6 - Current

PECO ENERGY COMPANY

GAS SERVICE TARIFF

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 3.

Issued February 26, 2026 Effective March 1, 2026

.

ISSUED BY: DAVID M. VAHOS - President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE.

LIST OF CHANGES MADE BY THIS SUPPLEMENT

SALES SERVICE COSTS (SSC) – 6th Revised Page No. 42
The Commodity Charges are increased. The Gas Cost Adjustment is increased.

MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – 6th Revised Page No. 46 and 6th Revised Page No. 47
The Merchant Function Charges are increased. The Prices to Compare are increased.

BALANCING SERVICE COSTS (BSC) – 6th Revised Page No. 48
The Balancing Service Cost is increased.

TABLE OF CONTENTS

LIST OF COMMUNITIES SERVED

BUCKS COUNTY:
BOROUGHS: Bristol, Chalfont, Doylestown, Dublin, Hulmeville, Ivyland, Langhorne, Langhorne Manor, Morrisville, New Britain, New Hope, Newtown, Penndel, Telford, Tullytown, Yardley.

FIRST-CLASS TOWNSHIP: Bristol.

SECOND-CLASS TOWNSHIPS: Bedminster, Bensalem, Bridgeton, Buckingham, Doylestown, Falls, Hilltown, Lower Makefield, Lower Southampton, Middletown, New Britain, Newtown, Northampton, Plumstead, Solebury, Tinicum, Upper Makefield, Upper Southampton, Warminster, Warrington, Warwick, West Rockhill, Wrightstown.

CHESTER COUNTY:
CITY: Coatesville.

BOROUGHS: Atglen, Avondale, Downingtown, Elverson, Honey Brook, Kennett Square, Malvern, Modena, Oxford, Parkesburg, Phoenixville, South Coatesville, Spring City, West Chester, West Grove.

FIRST-CLASS TOWNSHIP: Caln.

SECOND-CLASS TOWNSHIPS: Birmingham, Charlestown, East Bradford, East Brandywine, East Caln, East Coventry, East Fallowfield, East Goshen, East Marlborough, East Nantmeal, East Nottingham, East Pikeland, Easttown, East Vincent, East Whiteland, Elk, Franklin, Highland, Honey Brook, Kennett, London Britain, Londonderry, London Grove, Lower Oxford, New Garden, Newlin, New London, North Coventry, Penn, Pennsbury, Pocopson, Sadsbury, Schuylkill, South Coventry, Thornbury, Tredyffrin, Upper Oxford, Upper Uwchlan, Uwchlan, Valley, Wallace, Warwick, West Bradford, West Brandywine, West Caln, West Fallowfield, West Goshen, West Marlborough, West Nantmeal, West Nottingham, West Pikeland, West Sadsbury, Westtown, West Vincent, West Whiteland, Willistown.

DELAWARE COUNTY:
CITY: Chester.

BOROUGHS: Aldan, Brookhaven, Chester Heights, Clifton Heights, Collingdale, Colywn, Darby, East Lansdowne, Eddystone, Folcroft, Glenolden, Haverford, Lansdowne, Marcus Hook, Media, Millbourne, Morton, Norwood, Parkside, Prospect Park, Radnor, Ridley Park, Rose Valley, Rutledge, Sharon Hill, Swarthmore, Trainer, Upland, Yeadon.

FIRST-CLASS TOWNSHIPS: Aston, Darby, Lower Chichester, Marple, Nether Providence, Ridley, Springfield, Tinicum, Upper Chichester, Upper Darby.

SECOND-CLASS TOWNSHIPS: Bethel, Chadds Ford, Chester, Concord, Edgmont, Haverford, Middletown, Newtown, Radnor, Thornbury, Upper Providence,

LANCASTER COUNTY:
BOROUGH: Christiana

SECOND-CLASS TOWNSHIPS: Sadsbury, Salisbury.

MONTGOMERY COUNTY:
BOROUGHS: Ambler, Bridgeport, Bryn Athyn, Collegeville, Conshohocken, East Greenville, Green Lane, Hatboro, Hatfield, Jenkintown, Lansdale, Narbeth, Norristown, North Wales, Pennsburg, Pottstown, Red Hill, Rockledge, Royersford, Schwenksville, Souderton, Telford, Trappe, West Conshohocken.

FIRST-CLASS TOWNSHIPS: Abington, Cheltenham, Hatfield, Lower Merion, Lower Moreland, Lower Pottsgrove, Plymouth, Springfield, Upper Dublin, Upper Gwynedd, Upper Moreland, Upper Pottsgrove, West Norriton, West Pottsgrove.

SECOND-CLASS TOWNSHIPS: East Norriton, Franconia, Horsham, Limerick, Lower Frederick, Lower Gwynedd, Lower Providence, Lower Salford, Marlborough, Montgomery, Perkiomen, Salford, Skippack, Towamencin, Upper Frederick, Upper Hanover, Upper Merion, Upper Providence, Upper Salford, Whitemarsh, Whitpain, Worcester.

HOW TO USE LOOSE LEAF-TARIFF

1. This Tariff is issued on the loose-leaf plan. Each page will be issued as "original page", consecutively numbered, commencing with the title page, which in all cases will be considered as Page No. 1. For example: "Original Page No. 2", "Original Page No. 3," etc.

2. All changes in, additions to, or eliminations from, original pages, will be made by the issue of consecutively numbered supplements to this Tariff and by reprinting the page or pages affected by such change, addition, or elimination. Such supplements will indicate the changes which they effect and will carry a statement of the make-up of the Tariff, as revised. The Table of Contents will be reissued with each supplement.

3. When a page is reprinted the first time, it will be designated under the P.U.C. number as "First Revised Page No...," the second time as "Second Revised Page No. ..." etc. First revised pages will supersede original pages; second revised pages will supersede first revised pages, etc.

4. When changes or additions to be made require more space than is available, one or more pages will be added to the Tariff, to which the same number will be given with letter affix. For example: If changes were to be made in Original Page No. 2 and, to show the changed matter, more than one page should be required, the new page would be issued as "First Revised Page No. 2, superseding Original Page No. 2"; and the added page would be issued as "Original Page No. 2A." If a second added page should be required, it would be issued as "Original Page No. 2B." Subsequent reprints will be consecutively designated as "First Revised...," "Second Revised...," etc.

5. On receipt of a revised page, it will be placed in the Tariff immediately following the page which it is to supersede, and the page which is to be superseded thereby plainly marked "See following page for pending revision." On the date when such revised page becomes effective, the page superseded should be removed from the Tariff.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS

Aggregation Services Fee - A charge of 1¢/mcf applicable to all Low Volume Sales and Transportation Customers to be added to such Customers' Variable Distribution Service Charge effective January 1, 2001.

Available rate - A rate which may be obtained by a Customer if the use of service conforms to the character of service contemplated in the rate, and the Customer's location is such that this service can be supplied from existing facilities of the Company.

Bad credit (for deposit purposes) - A customer shall be deemed by the Company to have bad credit if the customer has been delinquent on payment of two consecutive bills or three or more bills in the last twelve billing cycles or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles. Industrial and commercial customers also shall be deemed by the Company to have bad credit if the customer is insolvent, (as evidenced by a credit report prepared by a reputable credit bureau or credit reporting agency or public financial data, liabilities exceeding assets or generally failing to pay debts as they become due) or has a class of publicly-traded debt outstanding that is rated to be below investment grade, or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles.

Balancing Service Cost or ("BSC") – Charge to all Low Volume Customers, both Sales and Transportation, included in Variable Distribution Charges, for fixed and variable storage costs for each Mcf of gas delivered under Rate Schedules GR, CAP, GC, OL, L, and MV-F of this Tariff, or the successors thereto.

British thermal unit (Btu) - The quantity of heat necessary to raise the temperature of one pound of water one degree Fahrenheit from 58.5 to 59.5 degrees Fahrenheit under standard pressure of 30 inches of mercury at or near its point of maximum density. One Btu equals 252 calories, (gram), 778 foot-pounds, 1,055 joules or 0.293 watt hours

Ccf – 100 cubic feet. This is a measure of gas usage.

Chapter 56 – The PUC regulations that govern metering, billing and collections for residential gas and electricity service.

Commodity Charge ("CC") – The "C" factor component of the Sales Service Cost representing the charge to Low Volume Sales Customers for purchased gas costs for each McF of Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff, or the successors thereto.

Commission or PAPUC– The Pennsylvania Public Utility Commission.

Company – PECO Energy Company

Competition Act - the Natural Gas Choice and Competition Act, 66 Pa.C.S. §2201, et seq.

Competitive Natural Gas Supply - firm natural gas provided by an NGS to Low Volume Transportation Customers under the Company's Gas Choice program.

Consolidated NGDC Billing – Billing provided by the Company that contains both the Company's charges for its services and the NGS's separate charges for gas supply services.

Creditworthy - A creditworthy customer pays the Company's charges as and when due and otherwise complies with the Rules and Regulations of this Tariff or the PaPUC. To determine whether a customer is creditworthy with respect to a particular account, the Company will evaluate the customer's record of paying Company charges for all of the customer's other Company accounts, and may also take into consideration the customer's general credit.

cu. ft. - Cubic foot.

Customer - Any person, partnership, association, or corporation, lawfully receiving service at a single meter location from the Company. In addition, unless explicitly prohibited by the Public Utility Code or the Commission's Rules or Regulations, an NGS may act as an agent for a Customer upon written authorization to PECO Energy, which authorization may be included in the notice of NGS selection.

Daily quantity - The quantity of gas used in a 24-hour period beginning at 10:00 a.m., Eastern Standard Time or Daylight Savings Time, whichever is in common use.

Delivery point - That point at which the Customer's facilities are connected to the Company's facilities which is typically the first fitting after the outlet side of the meter connection. or in certain cases the first fitting after the outlet side of the regulator or relief valve if located downstream of the meter.

Firm Service - Natural gas service offered to Customers under tariffs or contracts that anticipate no interruption of natural gas service.

Fixed Distribution Service Charge – A charge to recover costs caused by the presence of the Low Volume Customer on the system, other than the costs associated with the Customer's usage.

Gas Choice – Program under which Suppliers provide Competitive Natural Gas Supply to Low Volume Transportation Customers.

Gas Cost Adjustment ("GCA") Charge – The "E" factor component of the Sales Service Cost representing the net overcollection or undercollection of purchased gas costs, charged to Low Volume Sales Customers for each Mcf of Sales Service gas supplied under Rate Schedules GR, GC, CAP, OL L, and MV-F or the successors thereto.

High Volume Transportation (HVT) - PECO Energy's Gas program as administered by this tariff for Suppliers providing Competitive Natural Gas Supply to High Volume Transportation Customers.

High Volume Transportation Customers - Customers who purchase natural gas from an alternative Supplier under Rates Schedules TS-F, TS-I and/or the successors thereto, and not under the Company's Gas Choice program.

Holidays - New Year's Day, Martin Luther King, Jr.'s Birthday, Presidents' Day, Good Friday, Memorial Day, Juneteenth, Independence Day, Labor Day, Columbus Day, Veterans Day, Thanksgiving Day, Friday after Thanksgiving, Christmas, and Sundays

Initial Contract Term - The Customer's initial contract term, or in the case of transportation service, any renegotiation of an existing contract, for a service location shall be the Customer's first term of contract for service as specified under a given tariff rate or contract agreement to a location and shall also be the first term of contract after the Customer changes service at a location to a different rate, or in case of transportation service, any renegotiation of an existing contract.

Low Volume Customers – Customers served under Rate Schedules GR, GC, CAP, OL, L, and MV-F or successors thereto.

Low Volume Sales Customer – Low Volume Customers served under Rate Schedules GR, GC, CAP, OL, L, and MV-F who purchase their gas from the Company.

Low Volume Transportation Customers ("LVT Customers") - Low Volume Customers who purchase Competitive Natural Gas Supply from a Supplier pursuant to the Company's Gas Choice program, under Rates Schedules GR, GC, OL, MV-F or the successors thereto, and not under Rate Schedules CAP, L, TCS, IS, MV-I, TS-F, TS-I, and/or the successors thereto.

Master Meter System - a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter (i.e., Master Meter) or by other means, such as by rents.

Mcf – 1,000 cubic feet. This is a measure of gas usage.

Month - A month under this Tariff means 1/12 of a year, or the period of approximately 30 days between two regular consecutive meter readings dates of the Company's meter or meters installed on the Customer's premises.

Natural Gas Distribution Company ("NGDC") - a public utility that owns natural gas distribution facilities, used at times in this Tariff to refer to the role of the Company as the distributor of Competitive Natural Gas Supply pursuant to the Competition Act.

Natural Gas Supplier ("Supplier" or "NGS") - A natural gas supplier as defined in 66 Pa.C.S. § 2202, that has been licensed by the Pennsylvania Public Utility Commission to sell Competitive Natural Gas Supply to Low Volume Transportation Customers on the Company's system under the Company's Gas Choice program, to sell natural gas to Customers under Rates TCS, IS and/or MV-I or to sell natural gas to High Volume Transportation Customers under Rate Schedules TS-F, TS-I, and/or any other entity that takes title to gas as defined in 52 Pa. Code § 62.101

Natural Gas Supplier Coordination Tariff – The Tariff, setting forth the basic requirements for interactions and coordination between the Company, as the natural gas distribution company, and Suppliers necessary for maintaining the delivery of Competitive Natural Gas Supply from Suppliers to their Low Volume Transportation Customers under the Company's Gas Choice program.

Principal Office - The Company's Main Office Building located at 2301 Market Street, Philadelphia, Pa. 19103.

Property line - The division line between land held in, or for, private use, and land in which the public or the Company has a right of use; or the division line between separately owned or occupied land.

Sales Service Cost ("SSC") - Cost of commodity and non-storage interstate pipeline firm transportation capacity to delivery such commodity to the city gate for Low Volume Sales Customers.

Rate - The rates are CAP, GR, GC, OL, L, MV-F, MV-I, IS, TCS, TS-I, TS-F, and NGS or the successors thereto.

Separate NGS Billing ("Dual Billing") – Separate Billing by an NGS of its charges for gas supply service.

Service - The distribution of gas for use by the Customer, including all things done by the Company in connection with such distribution.

Service-Supply Pipe - The pipe extending from the Company's supply main to a metered delivery point or, in the case of installations comprised exclusively of outdoor gas lights, to the first such light.

Summary Billing Accounts - An aggregate bill prepared at the option of the Company for Customers with multiple accounts that are related within the same partnership, association, corporation or governmental agency.

Supplier of Last Resort Service ("SLR Service" or "Sales Service") - Natural gas supply service provided by the Company as supplier-of-last-resort to residential, small commercial, small industrial and essential human needs Customers who: (1) do not choose a Supplier or chose to be served by their supplier of last resort; (2) who are refused service by a Supplier; (3) whose Supplier has defaulted or exited the system; or (4) who return to SLR service after having obtained Competitive Natural Gas Supply.

System Maintenance Order ("SMO") – operational directive issued by the Company in its sole discretion to protect the operational integrity of its systems in terms of line pressure and adequacy of supply, which orders directly affect the quantity of gas to be delivered on the same gas day or other near-term gas days and may require a Customer or class of Customers, or a Customer's natural gas supplier or agent, to maintain, decrease or increase the quantity of natural gas delivered to the Company's system.

Tariff – This Gas Service Tariff comprising the rates, rules and regulations that apply to the distribution of natural gas, including all things done by the Company in connection with such distribution and/or the supply of natural gas under Supplier of Last Resort (Sales) Service.

Transportation Service – Natural gas supply service provided to HVT Customers, by an alternative Natural Gas Supplier as further detailed in Rule 1.1 of the Gas Transportation Service General Terms and Conditions Section of this Tariff.

Variable Distribution Service Charge – The variable charges on a Mcf basis for the provision of unbundled distribution service, including all things done by the Company in connection with such distribution service.

Volume Adjustment - the current adjustable factor applied to all rate classes to account for: a) reduction for system losses of 3.3% and b) thermal correction, the latter being determined by dividing the daily average Btu content per cubic foot of gas for the Company's system by a reference Btu content of 1,000 Btu per cubic foot. **(C)**

(C) Denotes Change

RULES AND REGULATIONS

1. THE GAS SERVICE TARIFF

1.1 FILING AND POSTING. A copy of this Tariff, which comprises the Rates, Rules and Regulations under which service and SLR (Sales) Service will be supplied to its Customers by PECO Energy Company, is on file with the Pennsylvania Public Utility Commission and is posted and open to inspection at the Principal Office of the Company. A copy of this Tariff also is available on the Company's website at: peco.com

1.2 REVISIONS. This Tariff may be revised, amended, supplemented or otherwise changed from time to time in accordance with the Pennsylvania "Public Utility Law", and such changes, when effective, shall have the same force as the present Tariff.

1.3 APPLICATION. The Tariff provisions apply to everyone lawfully receiving service from the Company, under the rates therein, and receipt of service shall constitute the receiver a Customer of the Company as the term is used herein, whether service is based upon contract, agreement, accepted signed application, or otherwise. A Customer will receive service under this Tariff effective with their first scheduled billing cycle beginning after July 1, 2000.

1.4 BASIS OF CHARGE. Time elapsed is a factor in the supply of service and the rates and minimum charges named in this Tariff, while predicated on periods of supply of not less than one year, are stated in values for direct application only to monthly periods of service provision and will be adjusted for application to service provided during other time intervals.

1.5 RULES AND REGULATIONS. The Rules and Regulations, filed as a part of this Tariff, are a part of every contract for service made by the Company and govern all classes of service where applicable, unless specifically modified by a rate or rider provision. The obligations imposed on customers in the Rules and Regulations apply as well to everyone receiving service unlawfully and to unauthorized use of service.

1.6 USE OF RIDERS. The terms governing the provision of service under a particular rate may be modified or amended only by the application of standard riders, filed as part of this Tariff.

1.7 STATEMENT BY AGENTS. No representative has authority to modify a Tariff rule or provision, or to bind the Company by any promise or representation contrary thereto.

RULES AND REGULATIONS - Continued

2. SERVICE SPECIFICATIONS

2.1 CHARACTER. This Tariff applies only to the distribution and/or supply of natural gas, or its equivalent. Supply pressures will be limited in accordance with Company specifications.

2.2 SINGLE-POINT DELIVERY. The rates named in this Tariff are based upon the Company’s distribution and/or supply through a single delivery point. Separate distribution and/or supply for the same Customer at other points of delivery shall be billed separately unless otherwise specifically provided for under a rate or rider statement.

2.3 SINGLE-POINT AVAILABILITY. Service delivered at a single point is available to one or more buildings or units devoted essentially to a single purpose, provided and so long as:

a. Such buildings or units are:

(1) held, possessed, and either utilized or operated as a single establishment by a single responsible entity, and

(2) unified on the basis of family, business, industry, enterprise, or governmental agency or through conveniences and services, such as heat, elevator, janitor, care of halls, walks and lawns, etc., furnished by such entity, and

(3) situated on a single or on contiguous land parcels except where such buildings or units constitute interdependent parts of a single industrial enterprise. In determining "contiguity" hereunder of parcels abutting opposite sides of public or private ways, the boundaries of such parcels shall be considered as extending to the center of such ways.

b. There is granted and maintained to the Company easement or other rights, adequate in the Company's reasonable judgment to supply service direct to any such buildings or units if, as and when a cessation of any one or more of the conditions stated in paragraph lettered "a" above should occur, or there should arise in any manner a Company duty of such direct supply.

c. The distribution and other facilities on the Customer's side of the delivery point are:

(1) furnished, installed and maintained at the expense of the Customer, and

(2) owned or leased by the Customer, and

(3) operated and controlled by or at the expense of the Customer.

d. The Company is under no legal obligation of direct supply to any portion of said buildings or units or their appurtenances.

e. A guarantee by deposit or otherwise is given and maintained to the Company sufficient in its reasonable judgment to insure it against loss in distribution and other investment in the event of change in the nature of holding and possession of such buildings or units, or in the occupancy thereof, or in the type of service delivered thereto.

f. All utilization equipment on the Customer's side of the Company delivery point is furnished, installed, operated and maintained by the operator of the buildings or units supplied or by the tenants of such operator whose use of gas is dependent upon the single point delivery and metering of service.

g. Any use of public highways by such operator for the latter's distribution facilities does not conflict or interfere with the franchise rights of the Company.

2.4 COMPLIANCE WITH AVAILABILITY. The use of the Company's service shall not be for any purpose other than that covered by the availability provisions of the rate or rider under which service is supplied.

2.5 COMPLIANCE WITH BUILDING ENERGY CONSERVATION ACT STANDARDS. Prior to furnishing permanent residential service for heating or cooling purposes to new residential buildings, a copy of the Compliance Certification from the Pennsylvania Department of Community Affairs indicating proof of compliance with, or exemption from, the insulation standards set forth in the Building Energy Conservation Act and the regulations promulgated thereunder, will be required for residential buildings located in municipalities that have not elected to administer the Act.

RULES AND REGULATIONS - Continued

3. CUSTOMER'S INSTALLATION

3.1 INFORMATION FROM APPLICANT FOR SERVICE. The Company should be advised by the applicant for service in writing, preferably on a form supplied by the Company, of premises to be equipped for gas, giving exact location, and details of all gas appliances to be installed.

The applicant for service shall supply the Company information regarding potential or actual contamination, waste or other materials or other adverse environmental conditions on the Customer's premises on or near where the Company facilities are to be located. The Customer has a continuing obligation to provide the Company with copies of any environmental assessment relating to the premises. The Company also has a continuing right to inspect the Customer's premises for the purposes of performing an environmental assessment.

3.2 DELIVERY POINT. The Company will designate in writing, upon request, a satisfactory point at which the Customer shall terminate the Customer's piping for connection to the facilities of the Company. The failure to request and obtain such information may result in refusal of service pending rearrangement of Customer's facilities, but the designation of a termination point does not constitute an agreement or obligation on the part of the Company to furnish service.

In establishing a point of delivery, the Company has the right to avoid areas known or suspected to contain contamination waste or other materials or other adverse environmental conditions.

The Company may waive this right upon agreement from the Customer or applicant to indemnify, defend and hold harmless the Company (its successors, assigns, trustees, officers, employees and agents) from and against all actions, causes of action, claims and demands whatsoever, and from all costs, damages, expenses, losses, charges, debts and liabilities whatsoever (including attorney's fees), whether known or unknown, present or future, that arise from such conditions. This indemnification provision shall survive the termination or expiration of this Agreement and the termination of the business relationship of the parties hereto.

3.3 METER LOCATION. There shall be provided, free of expense to the Company, at a location outdoors, unless otherwise designated by the Company, which the Company will designate in writing upon request, a suitable place for the regulator or regulators, meter or meters, and any other supply, protective or control equipment of the Company which may be required in the delivery of gas service. Meters and regulators must be located outside and above ground in accordance with 52 Pa. Code § 59.18. However, meters and service regulators cannot be installed in locations specified in 52 Pa. Code § 59.18(a)(8)(i-vi). Inside meter and service regulator locations shall be considered by the Company, but only in accordance with the exceptions contained in 52 Pa. Code §59.18(d). The Company may also consider other meter or regulator locations (such as a specially constructed cabinet recessed in the building wall, sealed from inside the building and vented to and accessible from outside the building) per 52 PA Code §59.18(e). The customer shall provide access (see Rule 10.5) and space, in an amount deemed necessary by the Company, to install and maintain its meter(s) and equipment. This location shall be convenient, unimpeded and easily accessible to the Company's employees, contractors and agents. The Customer shall also minimize any risk for damage and/or harm to the Company’s employees, contractors, agents and equipment at the meter location. There also must not be any impediment or obstruction of the Company’s ability to receive, an adequate communication signal from its meter(s) for remote reading purposes. The meter(s) location also shall be situated so that the meter(s) are not concealed, but shall be situated in a manner acceptable to the Company.

3.4 NONSTANDARD SERVICE. The Customer shall pay the cost of any special installation necessary to meet any peculiar requirements for service.

The Customer shall pay all costs to the Company of performing environmental assessments, including consultant costs and the costs of removal and disposal of hazardous materials associated with either the initial installation of service, modifications to the service or repair and maintenance of service.

3.5 REVERSE FLOW. The Customer may be required to install check-valves, or other devices, to prevent compressed air or other gases from entering the Company's mains.

3.6 EXCESS FLOW VALVES (“EFVs”). For new and replaced service line installations, the Company will install an Excess Flow Valve (EFV) at its own expense pursuant to 49 C.F.R. § 192.383, (defined in § 192.383(a), as required in (b) with exceptions in (c)). Eligible customers who request installation of an EFV on existing service lines (per § 192.383(d)), must pay the installation costs before any work begins.

RULES AND REGULATIONS - Continued

4. APPLICATION FOR SERVICE

4.1 METHOD OF APPLICATION. Customers may apply for service via the Company's website at http://www.peco.com or, in some cases, over the telephone. **(C)**

4.2 SERVICE CONTRACT. Every applicant for service may be required to sign a contract, agreement, or other form, then in use by the Company, covering the special circumstances of the use of gas, and shall abide by these Rules and Regulations and the standard requirements of the Company.

4.3 CONTRACT DATA. The application shall contain a statement of the premises to be served, the rate under which service is desired, and such conditions or riders as are applicable to the special circumstances of the case.

4.4 RIGHT TO REJECT. The Company may place limitations on the amount and character of service it will supply or may reject applications for service not available under a standard rate, or which might affect the supply of service to other Customers, or to be delivered at a location which involves excessive cost; for bad credit; for the applicant's' failure to provide identifying documentation; when an applicant's self-identification cannot be verified; or for other good and sufficient reasons. Customer can be denied SLR (Sales) Service or new service for failure to pay an NGS's charges.

The Company has the right to restrict service to only those locations which will not expose the Company to liability for known or suspected contaminated waste or materials or other adverse environmental conditions.

4.5 ACCEPTANCE. When an application is accepted, or when service is supplied according thereto either without modification or with supplemental agreement, it constitutes the contract between the Customer and the Company, subject to the Rules and Regulations.

4.6 SPECIAL CONTRACTS. Standard contracts shall be for terms as specified in the statement of the rate, but where large or special investment is necessary for the supply of service, or where service is to be used for an emergency or temporary replacement of another method of operation, contracts of longer term than specified in the rate, or with special guarantees of revenue, or both, may be required.

4.7 UNAUTHORIZED USE. Unauthorized connection to the Company's service-supply facilities, and/or unauthorized use of utility service, may be terminated by the Company without notice. Unauthorized use of utility service means unreasonable interference or diversion of service, including meter tampering any act which affects the proper registration of service through a meter, by-passing (unmetered service that flows through a device connected between a service line and Customer-owned facilities), and unauthorized service restoral. In cases of tampering or by-passing, the use of service without notifying the Company and enabling it to read its meter will render the user liable for any amount due for service supplied to the premises from the time of the last reading of the meter, immediately preceding the Customer's occupancy, as shown by the Company's books.

4.8 WITHDRAWAL OF APPLICATION BY NON-RESIDENTIAL CUSTOMERS. In the event the Customer or potential Customer withdraws, in whole or in part, an application for either new or modified service, the Customer will reimburse the Company for all reasonable costs incurred by the Company in anticipation of supplying the new or modified service where such costs were described by the Company to the Customer at or before the time application was made. This provision does not apply to individual residential service applicants.

(C) Denotes Change

RULES AND REGULATIONS - Continued

5. CREDIT

5.1 PAYMENT OBLIGATION. The provision of service for any purpose, at any location, is contingent upon payment of all charges provided for in this Tariff as applicable to the location and the character of service.

5.2 PRIOR DEBTS. Service will not be furnished to applicants or former customers until any indebtedness to the Company for previous service of the same or similar classification has been satisfied or a payment arrangement has been made on the debt. The Company may, at its discretion, determine liability for prior debts or past due balances by: (1) the use of company records that contain information provided to the Company; (2) information contained on a valid mortgage, lease, deed or renter's license; (3) the use of commercially available public records databases; (4) Government and property ownership records. This rule does not apply to the disputed portion of disputed bills under investigation. The Company will apply this rule to the disputed portion of disputed bills, if, and only if: (1) the Company has made diligent and reasonable efforts to investigate and resolve the dispute; (2) the result of the investigation is that the Company determines that the customer's claims are unwarranted or invalid; (3) the Commission and/or the Bureau of Consumer Services has decided a formal or informal complaint in the Company's favor and no timely appeal is filed; and (4) the customer nevertheless continues to dispute the same matter in bad faith.

5.3 GUARANTEE OF PAYMENTS. The Company may charge a security deposit before it will render service to an applicant or before the Company will continue to render service to a customer for whom the Company provides Consolidated EDC Billing or Separate EDC Billing. The Company may charge deposits to applicants and customers if they have bad credit, lack creditworthiness or as otherwise permitted by Commission statutes, rules, regulations, and as required by Federal Bankruptcy Law. The applicant or customer may be required to provide a cash deposit, letter of credit, surety bond, or other guarantee, satisfactory to the Company. The Company will hold the deposit as security for the payment of final bills and in compliance with the Company's Rules and Regulations. In addition, the Company may require industrial and commercial customers to post a deposit at any time if the Company determines that the customer is no longer creditworthy or has bad credit or as otherwise permitted by Commission statutes, rules, regulations and as required by Federal Bankruptcy Law. The Company retains the right to charge customers additional deposits based upon continued bad credit or lack of creditworthiness and increased usage.

5.4 AMOUNT OF DEPOSIT. For residential customers the deposit will be equal to one-sixth of the applicant's or customers estimated annual bill for Company charges, based on applicable rates. A deposit from a residential customer shall conform to the requirements of 66 Pa. C.S. 1404(c) and applicable Pennsylvania Public Utility Commission regulations. For industrial and commercial accounts, the amount of the deposit shall be the Company's projection of the sum of the Company charges in the customer's two highest monthly bills in the 12 months following the deposit. The provisions of 11 U.S.C. §366(b) of the Federal Bankruptcy Code, or any successor statute or provision, shall, if inconsistent, supersede the provisions of this rule. Deposits required by the Company for Tariff regulated charges shall not be based on unpaid supplier charges.

. 5.5 RETURN OF DEPOSIT Deposits secured from a residential Customer shall be returned with accrued interest, in accordance with 66 Pa. C.S.§1404(C) and applicable Pennsylvania Public Utility Commission regulations In cases of discontinuance of service, deposits will be returned with accrued interest upon payment of all service charges and guarantees or with deduction of unpaid accounts. Effective July 1, 2011, PECO will return the deposit on a non-residential account if the account was assessed fewer than two late payments in the previous 24 months. The first annual review of the customer's payment status will occur 24 months after the initial deposit date. Any residential or commercial customer having secured the return of a deposit may be required to make another deposit, in accordance with Commission statutes, regulations, or Federal Bankruptcy Law, if the Customer demonstrates bad credit or lacks creditworthiness subsequent to the return of the initial deposit.

5.6 INTEREST ON DEPOSIT. The Company will allow simple interest on cash deposits calculated as follows:

(1) with respect to residential accounts:

(a) interest accrued prior to December 14, 2004, at an annual rate determined by the average of the 1-Year Treasury Bills for September, October and November of the previous year ("Interest Index");

(b) interest accrued on or after December 14, 2004, at an annual rate determined by the legal rate of interest pursuant to 66 Pa. C.S.A. § 1404(C)(6);

(2) with respect to commercial and industrial accounts, at the lower of the Interest Index or six percent;
provided that interest accrued prior to April 14, 1995 shall be calculated at six percent. Deposits shall cease to bear interest upon discontinuance of service (or, if earlier, when the Company closes the account).

5.7 CREDIT INFORMATION.

CUSTOMERS: In addition to information required otherwise hereunder, customers for whom the Company provides Consolidated NGDC Billing or Separate NGDC Billing shall be required to provide to the Company with such credit information, as the Company requires. The Company may report to a national credit bureau on credit history associated with past due amounts.

APPLICANTS: The Company's credit and application procedures for applicants are as follows: (1) positive identification of applicant obtained from previous customer record or through one of the major credit reporting bureaus; (2) determination of liability for a past due balance; (3) determination if a deposit **(C)**
is required based upon applicant's previous account history if available or through third party credit scoring of applicant.
The Company's credit scoring methodology and standards are as follows: The Company uses a commercially recognized credit scoring methodology that is within the range of generally accepted industry practice. The applicant's or customer's utility payment history determines the credit score. The Company uses this customer-specific credit score to either request or waive a security deposit.

(C) Denotes Change

RULES AND REGULATIONS - Continued

6. SERVICE-SUPPLY FACILITIES

6.1 COMPANY'S SERVICE-SUPPLY PIPE. The Company will install, own and maintain the required service-supply pipe with Company participation in the cost of installation determined by the Company in accordance with Section 7 Extensions.
6.2 SERVICE-SUPPLY ALTERATIONS. Changes in location of service-supply pipe, or meter and connections, for the accommodation of the Customer, shall be at the expense of the Customer. A customer or building owner requesting that a meter or regulator be moved shall pay the costs associated with relocation when the meter and regulator are currently situated in a suitable location under State and Federal regulations per PA 52 Code § 59.18(a)(11).
6.3 STUB-SERVICE PIPE. When supply mains are in place, service-supply pipe to a point beyond the curb line may be installed, at the option of the Company, ahead of paving, providing the owners of the abutting property shall request and pay for such stub-service pipe. The cost of any such stub-service pipe may be refunded to the Customer over a term of years, upon such basis or condition as may be determined by the Company and specified in the contract for service.
6.4 METERS AND REGULATORS. The Company will provide, own and maintain any meter or meters, regulator or regulators, required in the supply of service.

7. EXTENSIONS

7.1 SUPPLY MAIN CONSTRUCTION. The Company will install, own and maintain gas supply mains located on the highway or on rights-of-way acquired by the Company and used or usable as part of the Company's general supply system.
7.2 OBLIGATION TO EXTEND. Subject to the terms set forth herein, the Company will extend its facilities to a new point of delivery without charge to a potential customer making a valid request for natural gas service. For additional details see Section 7.3, Service Pipe and Main Extension Policy.
7.3 SERVICE PIPE AND MAIN EXTENSION POLICY. When gas is available for sale to new customers under one of the Company's firm sales or transportation rate schedules, main and service facilities will be extended to an applicant in accordance with the following provisions:

A. General Economic Test. For firm service customers the Company will make a capital investment in the total cost of new main and service facilities to serve the customer (including, but not limited to, allocated overheads and related system modifications) when the net present value (NPV) from a proposed project is greater than or equal to zero. Net present value shall be calculated based on the capital investment, exclusive of the costs of meter and meter installation, required to serve the applicant(s) and the estimated base annual revenues (EBAR) generated from the applicant(s). The "EBAR" shall be calculated by multiplying the applicable Variable Distribution Charge rate (excluding any applicable gross receipts tax or certain fixed TCS costs) times the estimated annual consumption, plus the portion of annualized Fixed Distribution Charge attributable to service line capital costs. In calculating the NPV, the following assumptions will be made: 1) a 40 year evaluation period, 2) the discount rate shall be the Company's after–tax cost of capital, 3) revenue shall be assumed to be collected throughout the year, and 4) capital is assumed to be invested at the beginning of the year. If the proposed project has a negative NPV, the Customer shall make a payment to bring the net present value to a zero value. This will enable the proposed project to support a reasonable rate of return to the Company.

B. Developments. Payments shall be required in advance for all lot developments. If a payment is required, the amount of payment shall be based on the General Economic Test set forth in Section 7.3A and shall incorporate known gas applications in buildings under construction or buildings not yet under construction but which are expected to be fully constructed within a five year period from the date of the original contract signing. This requirement may alternatively be satisfied by payment of at least 35 percent of the required contribution upon execution of the service agreement with the remainder subject to payment bond and interest (at prime rate) and is due no later than 6 months after PECO certifies, in writing, that service is available to the development. At the time of execution of the service agreement, the developer shall also post a letter of credit, surety bond, or other security, satisfactory to the Company equal to 50% of the value of the revenue stream as calculated by the Company under Section 7.3A. If the developer does not fully develop the lots within five years, including, but not limited to, installing all required appliances and flowing natural gas to them, the Company reserves the right to use the security as payment for the contract amount. Lot developments are defined as tracts subdivided for sale as individual lots or groups of lots to more than one builder or buyer.

C. Interruptible Service Installations. The Company will make a capital investment in the total cost of new main, service facilities and dual fuel installations, (including, but not limited to allocated overheads and related system modifications) to serve Customers with interruptible service installations, up to an amount equal to three times the additional Estimated Base Annual Revenue (EBAR) attributable to the Customer. The Customer shall pay the cost, if any, in excess of the above limit exclusive of the costs of the meter and, meter installation.

D. After-tax cost of capital (discount rate) shall be determined on the basis of (1) the Company's capital structure and cost of long-term debt set forth in the Company's latest year-end Quarterly Earnings Report submitted to the Commission by March 31 of a year for the period ending December 31 of the previous year; and 2) the cost of equity approved in the most recent base rate case or, in the absence of a Commission determination or Commission approval of a stipulated cost of equity, the cost of equity that the Commission has determined should apply to Distribution System Improvement Charge ("DSIC") investment.

7.4 EXTENSION REFUNDS. Upon receipt of a written request by a Customer or developer made no earlier than the end of the third year following the date of an agreement for new gas service, PECO will: (a) review its records to determine if a refund is due the customer or the developer for additional customers beyond those used to calculate the projected revenue stream as determined in the General Economic Test above that attached to the facilities paid for by the customer or the developer within three (3) years after the execution date of the agreement for new gas service, and (b) within sixty (60) days of receipt of such request, (i) make payment to the customer or developer of any refund due and (ii) provide the customer or developer with documentation substantiating the refund calculations and identifying the attached loads for which the developer was credited. Customer or developer contributions may be refunded if, within three years of the date of the service agreement, new loads are added to facilities paid for by the contributing Customer or developer. Revenue and cost computations shall simulate that the original and new loads were installed at the same time. Refunds will be paid only to the contributing Customer or developer, and the original contribution shall be the maximum refund.

7.5 TAX ACCOUNTING OF CONTRIBUTIONS IN AID OF CONSTRUCTION AND CUSTOMER ADVANCES. All contributions in aid of construction (CIAC), customer advances or other like payments received by the Company shall constitute taxable income as defined by the Internal Revenue Service. The income taxes on such CIAC or customer advances will be segregated in a deferred account for inclusion in rate base in a future rate case proceeding. Such income taxes associated with CIAC or customer advances will not be charged to the specific contributor of the capital.

RULES AND REGULATIONS - Continued

8. RIGHTS-OF-WAY

8.1 TERM AND RENTALS. When the premises of a Customer is so located that the Customer can be served only by facilities extending over the property of another, the Customer shall accept service for such term as is provided in the permit or agreement covering the location and the maintenance of service equipment, and the Customer shall reimburse Company for any and all special or rental charges that may be made for such rights by said permit or agreement.

8.2 PROCUREMENT BY CUSTOMER. Customers applying for the construction of an extension may be required to secure to, and for, the Company, all necessary and convenient rights-of-way and to pay the costs incident thereto.

8.3 DELAYS. Applications for service from an extension to be constructed where a right-of-way is not owned by the Company will only be accepted subject to delays incident to obtaining a satisfactory right-of-way.

9. INTRODUCTION OF SERVICE

9.1 COMPANY'S RIGHT TO INSPECT. The Company shall have the right, but shall not be obliged, to inspect any installation before service is introduced or at any later time, and reserves the right to reject any piping or appliances not in accordance with the Company's standard requirements; but such inspection, or failure to inspect, or to reject, shall not render the Company liable or responsible for any loss or damage, resulting from defects in the installation, piping, or appliances, or from violation of Company rules, or from accidents which may occur upon the premises of the Customer.

9.2 DEFECTIVE INSTALLATION. The Company may refuse to connect if, in its judgment, the Customer's installation is defective, or does not comply with such reasonable requirements as may be necessary for safety or is in violation of the Company's standard requirements.

9.3 UNSATISFACTORY INSTALLATION. The Company may refuse to connect if, in its judgment, the Customer's equipment, or use thereof, might injuriously affect the equipment of the Company, or the Company's service to other Customers.

9.4 INITIAL SERVICE. In all cases gas shall be introduced to the Customer's installation by, or under the supervision of, a representative of the Company.

RULES AND REGULATIONS - Continued

10. COMPANY EQUIPMENT

10.1 COMPANY MAINTENANCE. The Company shall keep in repair and maintain its own property installed on the premises of the Customer.

10.2 CUSTOMER'S RESPONSIBILITY. The Customer shall be responsible for safekeeping of the Company's property while on the Customer's premises. In event of injury or destruction of any such property the Customer shall pay the costs of repairs and replacement. Any changes made to the Customer's premises after the Company completes its service and meter installation that, in the opinion of the Company, creates an unsafe condition, shall be the Customer's responsibility to pay any costs associated with remedying the unsafe condition including but not limited to any required protective measures and/or relocations of Company property. Customers with privately owned or operated underground utility facilities on their premises may have obligations as facility owners under the Underground Utility Line Protection Act, 73 P.S. Section 176 et. seq. These include becoming a member of Pennsylvania One Call, maintaining said facilities, and providing approximate locations of said facilities with temporary markings within the required time period in response to Pennsylvania One Call notifications. Customers should create and retain as-built drawings reflecting the locations of said facilities on the premises and revise these drawings as necessary to reflect any changes made following installation. If said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work, the Company has the right to require the associated customer to bear all incremental costs necessary to ensure safe digging by the Company, including but not limited to subsurface utility excavation and engineering, materials, supplies, transportation, labor, and overhead. If 1) said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work or 2) the Company is unable to notify a facility owner of its intent for excavation or similar work covered under the Act because the facility owner is not a member of the Pennsylvania One Call system, the Company shall not be liable to customers or any other third parties for any damages, including property damage, economic damages, costs, associated consequential damages or personal injuries.

10.3 PROTECTION BY CUSTOMER. The Customer shall protect the equipment of the Company on the Customer's premises, and shall not permit any person, except a Company employee having a standard badge of the Company or other Company identification, to break any seals upon, or do any work on, any meter, service-supply pipe or other equipment of the Company located on the Customer's premises.

10.4 TAMPERING. In the event of the Company's meters or other property being tampered or interfered with, the Customer being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter, and for any repairs or replacements required, as well as for costs of inspections, investigations, and protective installations.

10.5 RIGHT OF ACCESS. The Company's identified employees shall have access to the premises of the Customer at all reasonable times for the purpose of reading meters and disconnecting service, and for installing, testing, inspecting, repairing, removing or changing any or all equipment belonging to the Company. See 52 Pa. Code § 59.24.

10.6 OWNERSHIP AND REMOVAL. All equipment supplied by the Company shall remain its exclusive property, and the Company shall have the right to remove the same from the premises of the Customer at any time after the termination of service from whatever cause.

10.7 RELOCATION OF COMPANY FACILITIES REQUESTED BY NON-RESIDENTIAL PROPERTY OWNERS. Except as otherwise provided by law (e.g., 66 Pa. C.S. Section 2704 et seq.), a non-residential property owner, such as a builder, developer or contractor (Owner), shall compensate the Company for the costs of relocation of Company facilities or equipment, made for the accommodation of the Owner or in fulfillment of the Owner's obligation to any public authority.

If the facility relocation is made to accommodate the Owner's project or in fulfillment of the Owner's obligation to any public authority, then the Owner shall be responsible to pay PECO for the relocation costs even if the relocation request is made by an entity other than the Owner. A request for relocation of Company facilities shall be in writing. The relocation cost shall include labor (including overhead), materials, storeroom expense and transportation, less the depreciated value of any equipment replaced.

Where the relocation is done in conjunction with construction of a supply line to a development, the Company shall include in the relocation cost those costs caused by the Owner's request. Such relocation costs are not part of the capital investment toward supplying service and are, therefore, not included in the revenue test with which the line extension contribution is calculated.

The Company will notify the Owner in writing of the relocation cost. Advance payment of relocation costs will be required before the Company will commence the work, except, at the sole discretion of the Company, under special circumstances.

10.8 RECOVERY FOR PROPERTY DAMAGE. If Company equipment is damaged through the negligence or intentional act(s) of any individual(s) or entity(s), the one(s) responsible for causing the damage shall reimburse the Company for all aspects of the resulting damages. The reimbursement shall include costs related to: labor, material, transportation and tools. "Labor" shall include benefit and administrative overheads based on the Company's current standard schedule, including third party contract repairs or modifications. Additionally, "Labor" may be calculated using a "blended" or average pay rate consistent with the above referenced standards. "Materials" may include an added stores expense calculated using the above referenced standards.

RULES AND REGULATIONS - Continued

11. TARIFF OPTIONS ON APPLICATIONS FOR SERVICE

11.1 CHOICE OF RATE. Where the classes of service-supply or conditions of use are such that two or more rates are available, an applicant shall select the rate or rates to be applied to the applicant's service.

11.2 COMPANY ASSISTANCE. The Company upon request will, to a reasonable extent, assist an applicant in selecting the most advantageous rate or rate application.

11.3 RATE CHANGES. A Customer may not change rates during the "initial contract term" as defined in the "Definition of Terms and Explanation of Abbreviations" section above. At any other time, a Customer may change to a rate for which the Customer qualifies upon 30 days' notice to the Company. The new rate will be effective the next meter reading date after Company approval.

The Company will not make any rate change retroactive, unless the Company failed to adequately respond to a Customer's request for assistance or modification at the time of such request.

RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY

12.1 REGULARITY OF SUPPLY. The Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of service.

12.2 CURTAILMENT OF SERVICE.

a. Authority to Curtail. In the event of a natural gas emergency, the Company may curtail the availability of natural gas service to its Customers in accordance with this Rule 12.2.

b. Priority of Service. Following are the service priority categories listed in descending order of priority (highest to lowest):

Priority 1

(1) Residential and firm critical commercial essential human needs.

Priority 2

(2) Firm small commercial requirements, excluding critical essential human needs requirements in Category 1, and firm large commercial and industrial requirements for plant protection.

(3) Firm small industrial requirements.

(4) Firm large critical commercial and industrial requirements, excluding firm critical commercial essential human needs requirements in Category 1.

(5) Firm large non-critical commercial and industrial requirements other than requirements for boiler fuel use.

(6) Firm large non-critical commercial and industrial requirements for boiler fuel use.

Priority 3

(7) Contractually interruptible use.

c. Definitions Applicable. The definition for terms used in the Curtailment of Service Rule are as follows:

(1) Alternate Fuel Capability. The installed and operable ability to use any fuel other than natural gas on a time sensitive basis. For purposes of this definition, alternate fuel means any fuel other than natural gas or its equivalent.

(2) Commercial Use. Gas usage by Customers engaged primarily in the sale of goods or services including, but not limited to, consumption by office buildings, institutions and governmental agencies and shall include Customers in Standard Industrial Classification Codes 01 through 09, 15 through 19, and 49 through 99. Commercial use shall not include use of gas for manufacturing or electric power generation.

(3) Critical Use. Gas usage where natural gas, or its equivalent, is the only feasible form of energy due to its combustion characteristics, controllability or chemical properties.

(4) Essential Human Needs Use. Gas usage in any building where persons normally dwell, including residences, apartment houses, dormitories, hotels, hospitals, and nursing homes, where the Customer does not have alternate fuel capability.

(5) Firm Service. Natural gas service offered to Customers under tariffs or contracts that anticipate no interruption of natural gas service.

(6) Industrial Use. Gas usage by Customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power and shall include Customers in Standard Industrial Classification Codes 10 through 14 and 20 through 39.

(7) Interruptible Service. Natural gas services that can be temporarily discontinued under terms and conditions specified by tariff or contract.

RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY – Continued

(8) Large Customer. A customer with annual usage of at least 18,000 Mcf during the prior calendar year.

(9) Natural Gas Emergency. Whenever the aggregate demand of firm service customers on the Company's system or portion of the Company's system, for any reason, exceeds or threatens to exceed the gas supply or capacity that is actually and lawfully available to the Company to meet the demands, and the actual or threatened excess creates an immediate threat to the Company's system operating integrity or the ability of the Company to satisfy the demand requirements of its Priority 1 Customers (including when continued delivery of gas to Customers would prevent the Company to arrange for the injection of gas into underground storage pools necessary for the protection of winter season supply requirements).

(10) Non-Critical Use. Gas usage where natural gas is not the only feasible form of energy; i.e., where the Customer has alternate fuel capability.

(11) Small Customer. A customer with annual usage of less than 18,000 Mcf during the prior calendar year.

(12) System Maintenance Order ("SMO") – as defined in the definitions section of the tariff.

(13) Plant Protection Use. Minimum usage of natural gas required to prevent physical harm to an industrial or commercial customer's facility, or danger to personnel at the facility, when the protection cannot be afforded through the use of an alternative fuel. Plant protection requirements includes usage necessary for the protection of the material in process as would otherwise be destroyed, but does not include deliveries required to maintain production.

(14) Residential Use. Gas usage in a residential dwelling or unit for space heating, air conditioning, cooking, water heating, or other domestic purposes.

d. Curtailment Process.

(1) Reservation of Company Right to Curtail. The Company reserves the right to reduce or eliminate the availability of firm natural gas service to Customers during a natural gas emergency, on a system-wide or localized basis ("curtailment"), when, in the Company's sole judgment, curtailment of natural gas service is necessary to protect the integrity of service to Priority 1 customers and/or the Company's gas distribution system assets. When necessary, the Company may curtail service to Priority 1 customers.

(2) Pre-Curtailment Procedures. To avoid curtailment of service, the Company will use reasonable business and operational efforts to interrupt all Priority 3 services; issue appropriate system maintenance orders (SMO) to HVT and LVT Customers, their Natural Gas Suppliers or other agents; and/or request customers to institute voluntary usage reductions.

(3) Curtailment Directive. In the event that Pre-Curtailment Procedures are not practicable or fail to protect the integrity of service to Priority 1 customers and/or the Company's gas distribution system assets, the Company may issue a curtailment directive. The curtailment directive should be reasonably well-tailored by the Company to require Customers of lower priority services to reduce usage by an amount calculated by the Company, as necessary to minimize the potential threat to public health and safety and to minimize the effect of a natural gas emergency on the integrity of service to Priority 1 customers and/or the Company's gas distribution system assets but may be issued without regard to priorities of service. During the period specified by the curtailment directive, Customers directed to curtail usage must comply with the directive or face physical shut-off by the Company and/or the assessment of penalties elsewhere set forth in this Rule 12.

RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY – Continued

(4) Curtailment Sequence. Curtailment of a customer class of a higher priority shall not be initiated until all Customers falling into the lower classifications have been completely curtailed. Where only partial curtailment of any one classification is required, customer usage should be reduced pro rata to the extent reasonably possible. As applied to High Volume Transportation Customers served under Rate TS-F, pro rata reductions will be based on a percentage of the Customer's Transportation Contract Quantity unless the Customer has alternative fuel capability.
If the Customer has alternative fuel capability, a pro rata reduction shall be based on a percentage of the Customer's Transportation Contract Quantity less the daily alternative fuel capability. The Company shall restore service as soon as practicable to any gas-fired generation facility that is deemed critical to electric system reliability by the applicable electrical system's control area operator.

(5) Customer Notification. The Company shall provide maximum notice possible of a curtailment directive or of a change in curtailment amount or priority level set forth in a curtailment directive. In the curtailment directive, the Company shall specify the authorized consumption for a specified period or until further notice. The Company reserves the right to provide notice by any reasonable means, including by telephone, pager, e-mail, facsimile or personal contact. If such notice is by telephone, then it will be followed by a written notice to the Customer, specifying the Customer's curtailment percentage and resulting peak day, daily, monthly, seasonal or annual authorized entitlement, as the case may be. An emergency curtailment may be made after oral notice to the Customer, effective when so given, but such oral notice will be confirmed in writing within 48 hours.

(6) Commission Notification. The Company shall notify the Commission as soon as practicable after the issuance of a curtailment directive.

(7) Curtailment Directive Exceeding 5 Days. The Company must obtain Commission authorization before it may extend a curtailment directive beyond a maximum duration of 5 business days. Business days shall be all days except Saturdays, Sundays, and federal holidays.

(8) Natural Gas Emergency Plan. This Rule 12 is supplemented by Company procedures referenced in the Company's Natural Gas Emergency Plan filed by the Company in compliance with Commission Regulations, 52 Pa. Code § 59.63 and 59.71 et seq., and such procedures may be modified from time to time.

e. Unauthorized Use.

(1) Penalties. A Customer determined to have used natural gas in violation of a SMO issued pursuant to Rule 12.2.d(3) or a curtailment directive issued by the Company ("unauthorized use") shall pay the Company a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. Also, included will be the actual, additional cost incurred by the Company as a result of such unauthorized gas usage, as reasonably determined by the Company.

The term "market rate" shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-Non NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

(2) Disposition of Penalties. As of December 31, of each year, the Company shall subtract the total of all penalties paid that year to the Company's suppliers from penalties collected that year from Customers. The Company will then distribute all remaining penalties collected by the Company to its curtailed Customers who did not incur penalties under e(i) above.

(3) To determine the amount of reimbursement due a Customer, the total amount to be redistributed shall be divided by the total volume of sales during the twelve-month period to all Customers eligible for reimbursement. This quotient shall represent the factor, which when multiplied by an eligible Customer's total purchase volume during the twelve-month period will equal the amount to be credited to that Customer. However, no reimbursement shall be made to Customers who have terminated service during the year.

(4) The Company will make periodic reports to the Commission containing itemized statements, status of penalty accounts and the extent and nature of disbursements from such accounts made during that period.

RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY - Continued

12.3 LIMITATION OF LIABILITY. Should the supply of service be curtailed or interrupted by the Company because of gas shortage, or for the purpose of making repairs, changes or improvements, in any part of its system for the general good of the service or the safety of the public, or should the supply of service be interrupted, curtailed or fail, by reason of accident, weather, strike, legal process, state or municipal interference, or any cause whatsoever the Company shall not be liable for damages, direct or consequential, resulting from such interruption or failure unless such interruption or failure resulted from the Company's wanton or willful misconduct. If the supply of service to a firm service Customer is interrupted for more than seven consecutive days as a result of the Company's wanton or willful misconduct, the Customer's bill will be prorated for the month during which this interruption occurs.

In all other circumstances, including but not limited to failure to furnish a sufficient supply of gas or failure to transport the customer's gas to the customer, the liability of the Company to customers or other persons for damages, direct or consequential, including damage to equipment and appliances, loss of business, or loss of production caused by any interruption or variation in supply or pressure, or any other failure in the supply of natural gas shall in no event, unless caused by the willful and/or wanton misconduct of the Company, exceed an amount in liquidated damages equivalent to the greater of $1000 or two times the charge to the customer for the service affected during the period in which such interruption or variation in supply or pressure, or any other failure in the supply of natural gas occurs.

The Company makes no warranty as to merchantability or fitness for a particular purpose, express or implied, by operation of law or otherwise. To the extent applicable under the Uniform Commercial Code or on any theory of contract or products liability, the Company limits its liability in accordance with the previous paragraph to any Customer or third party for claims involving and including, but not limited to, strict products liability, breach of contract, and breach of actual or implied warranties of merchantability or fitness for an intended purpose.

12.4 ADDITIONAL LIMITATIONS OF LIABILITY IN CONNECTION WITH CUSTOMER CHOICE. Other than its duty to deliver natural gas, the Company shall have no other duty or liability to a Customer receiving Competitive Natural Gas Supply arising out of or relating to a contract or other relationship between such Customer and an NGS. The Company shall implement Low Volume Customer selection of an NGS consistent with applicable rules of the Commission and shall have no liability to a Low Volume Customer receiving Competitive Natural Gas Supply arising out of or relating to switching NGSs unless the Company is negligent in switching or failing to switch a Customer. The Company shall have no duty or liability with respect to natural gas before it is delivered by an NGS to a point of delivery on the Company's distribution system. After its receipt of natural gas at the point of delivery the Company shall have the same duty and liability for distribution service to Customers receiving Competitive Natural Gas Supply as to those purchasing natural gas from the Company.

12.5 NOTICE OF TROUBLE. The Customer must immediately notify the Company if there is any defect, leak, trouble or accident affecting the supply of gas.

RULES AND REGULATIONS - Continued

13. CUSTOMER'S USE OF SERVICE

13.1 RESALE OF SERVICE. As of January 5, 1980, the resale of gas and/or service provided by the Company is prohibited for Customers who receive gas service from the Company through a master meter and resell it to individual dwelling units by the use of submeters. Customers receiving service prior to January 5, 1980, may resell gas purchased from the Company through a single master meter in accordance with 66 Pa.C.S. § 1313 if the purchased gas is: (1) for the total requirements of the premises served and (2) the use of the resold gas conforms to the availability requirements of this tariff for the Customer's own account.

13.2 FLUCTUATIONS. Gas and/or service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system, and, in the case of violation of this rule, the Company may discontinue service, or require the Customer to modify the installation and/or equip it with approved controlling devices.

13.3 ADDITIONAL LOAD. Any additional loads, either connected to existing equipment or new equipment, will not be allowed except by consent of the Company.

13.4 FAILURE TO GIVE NOTICE. Failure to give notice of additions or changes in load or location shall render the Customer liable for any damage to the regulator, meters, or other equipment of the Company, caused by the additional or changed installation.

14. MEASUREMENT

14.1 SUPPLY OF METERS. The measurement of gas usage shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment, and may, from time to time, change or alter the equipment, its sole obligation being to supply meters that will accurately and adequately furnish records for billing purposes.

14.2 SPECIAL MEASUREMENTS. The Company shall have the right, at its option and its own expense, to place demand meters, pressure gauges, special meters, or other instruments, on the premises of any Customer for the purpose of determining the adequacy of the Company's service or for making tests of all or any part of the Customer's load.

14.3 METER READING INTERVALS. The Company will read its meters at scheduled regular intervals of one or more months and will render standard bills for the recorded gas usage based upon the time interval between meter readings. Only those bills which cover a period of service of less than 27 days or more than 34 days will be prorated.

14.4 ESTIMATED USAGE. The Company may estimate the amount of gas usage at the premises where access to the meter is not available, or to installations at remote locations, for such number of months as the type of installation, normal regularity of usage, or other circumstances may warrant, and will render bills in standard form based on such estimate and so marked, for the Customer's acceptance. Meter readings will be secured from time to time and billing will be revised when they disclose that the estimate failed to approximate the actual usage. For residential Customers, an actual meter reading will be obtained at least every six months, in accordance with Commission regulations.

14.5 CORRECTION TO STANDARD CONDITIONS. The quantities of gas used may be corrected to standard conditions, namely 60 degrees Fahrenheit temperature and 30 inches of mercury barometric pressure. All methods employed in correcting measurements of gas volume to said standard conditions shall be in accordance with established industry standards.

14.6 TELEMETRY AND TELEPHONE EQUIPMENT

(a) Customer shall permit PECO to install and operate telemetering equipment to remotely read PECO’s meter.

(b) Customer shall provide and pay for telephone service required for the operation of PECO’s equipment and/or the transmittal of data from PECO’s meter, as directed by PECO. Customer must maintain either a dedicated non-digital telephone line or telephone equipment that converts the digital signal to analog. Customer shall provide telephone service for this purpose at least fifteen (15) working days prior to the commencement of service under this agreement.

(c) Service will not be provided prior to the date on which Customer installs the required telephone service. Customer is responsible to maintain the telephone service in working order at all times.

(d) PECO will read the meter on the last day of the month if a reading is not transmitted. If PECO determines that the phone line is not functioning, Customer will be notified that the phone line must be repaired within thirty (30) days.

(e) If more than thirty (30) days elapse and the telephone service is not restored to working order to PECO’s satisfaction, then the following steps will be taken:

(1) If PECO has sufficient capacity in its gas supply system to supply Customer, then Customer's Account will be served as firm service on PECO's Rate GC-General Service–Commercial and Industrial, for a minimum of twelve (12) months.

(2) If PECO does not have sufficient capacity in its gas supply system to supply Customer, then PECO will disconnect Customer's facility from the PECO gas supply system for a minimum of twelve (12) months. During any such period of disconnection, Customer will use an alternate fuel to meet its heating and process needs.

RULES AND REGULATIONS - Continued

15. TESTS

15.1 METER TESTS. The Company, at its expense, will make periodic tests and inspections of its meters in order to maintain them at a high standard of accuracy. See 52 Pa. Code § 59.21.

15.2 REQUEST TESTS. The Company will make additional tests or inspections of its meters at the request of a Customer, or an NGS providing Competitive Natural Gas Supply to a Customer, but reserves the right to charge the Customer or NGS, as applicable, any Commission-approved charge as provided in the Commission's Gas Regulations.

15.3 ADJUSTMENT FOR ERROR. Should any meter become defective or fail to register correctly, the quantity of gas consumed shall be determined by a test of the meter, or by the registration of a meter set in its place during the period next following, or by averaging the amount of gas used for the nearest meter reading period preceding and the meter reading period immediately following the date when the meter was found not be to registering, taking into consideration the character of use by the Customer.

15.4 RESIDENTIAL METER ERRORS. Meter errors in residential service may be determined on the basis of the registration of the corresponding period during the preceding year, if records are available and conditions of use remain the same.

15.5 ADMINISTRATION TESTS. The Company, at its own expense, will make only such tests as it deems necessary for the proper administration of its rates, or as are required by law.

15.6 TESTING SERVICE. The Company will, upon request by the Customer, make tests to supply special information regarding the Customer's use of service, provided that the estimated cost of such special tests shall be paid by the Customer to the Company at the Company's discretion.

RULES AND REGULATIONS - Continued

16. PAYMENT TERMS

16.1 BILLING PERIOD. Billing for service will be based upon the amount of use and the time interval of its supply. Rate values stated for direct application to monthly periods will be adjusted when the time elapsed between readings is substantially greater or less than a month.

16.2 BILLING OPTIONS. A Low Volume Customer may select one of the following two billing options as communicated to PECO by the customers' supplier: (1) Consolidated NGDC Billing; or (2) Separate NGS Billing.

16.3 PAYMENT PERIOD. Bills are payable upon presentation, and payment may be made at any authorized payment agency. **(C)**
Payment for service received must be made on or before the due date shown on the bill, which shall be not less than 20 days from the date of transmittal of the bill for Rate GR, GC and OL (excluding Summary Billing Accounts); not less than 15 days from the date of transmittal of the bill for all other rates, including Summary Billing Accounts, with the exception of accounts (including Summary Billing Accounts) with the United States of America or the Commonwealth of Pennsylvania or any of their departments or institutions for which 30 days will be allowed. If a normal due date should fall on a Saturday, Sunday, bank holiday, or any other day when the offices of the Company which regularly receive payments are not operating, the due date **(C)**
shall be extended to the next business day. The payment period will not be extended because of the Customer's failure to receive a bill unless said failure is due to the fault of the Company.

16.4 FINANCE CHARGE. If payment may be made at an authorized payment agency after the due date **(C)**
shown on the bill, a finance charge will be added to the unpaid balance until the entire bill is paid. If payment is made by mail, the finance charge will be added if the payment is received by the Company more than 5 days after the due date shown on the bill. For Rates GR, GC and OL, this finance charge will be 1-1/2% per month; for all other rates the finance charge will be 2% per month.

16.5 BUDGET BILLING

(a) At the option of a Customer receiving service under Rates GR, GC, and OL, an estimated total bill for all service to be received by the Customer over a twelve-month period may be budgeted over the period and an average bill rendered monthly for payment each month. Any difference between the budgeted amounts so paid and the actual charges for a twelve-month budget period will at the customer's option, either be amortized over the next twelve months or incorporated into the twelfth month bill. Absent an indication of preference from the customer, the debit or credit will be amortized. Budget billing may be discontinued upon the customer's request at which time any difference between budget billing amounts and actual charges becomes due and payable. If a monthly budget bill is not paid, a late fee will be added to the unpaid balance of actual charges on the next billing date in accordance with Rule 16.4. Any such late fee will be calculated based on the lesser of budget billing arrears and arrears from actual charges.

(b) When the Company provides Consolidated NGDC Billing, the NGSs charges will be included in the Customer's Budget Billing Plan.

16.6 CALCULATION OF FINANCE CHARGE. Where a finance charge is applicable, the amount of the finance charge to be added to the unpaid balance shall be calculated by multiplying the unpaid past due balance, exclusive of any previous unpaid finance charges, by the appropriate finance charge rate. Finance charges shall be applied to all charges when the Company is providing Supplier of Last Resort service and to the Fixed Distribution Service Charges, Variable Distribution Service Charges and any applicable service charges when the Customer has selected an NGS. The Company will apply finance charges to NGS charges at the NGS's electronic request when the Company is performing billing services for the NGS.

16.7 APPLICATION OF PAYMENT. When the Company provides Consolidated NGDC Billing or SLR (Sales) Service and a Low Volume Customer remits a partial payment to the Company, the payment will be applied as follows:

1. Any past due balances including those for prior PECO basic service charges, for prior NGS receivables purchased by the Company, for prior installment amounts on payment agreements, and also for any reconnection charges.
2. Any current charges including those for PECO basic service charges, for current NGS receivables purchased by the Company, and for current installment amounts on payment agreements.
3. Non-basic service charges.

(C) Denotes Change

16.8 RETURNED CHECK CHARGE. If a check received in payment of a Customer's account is returned to the Company unpaid by the Customer's bank and cannot be redeposited by the Company for payment on the second attempt, a $20.00 charge for the returned check will be added to the Customer's account.

16.9 BILLING ERRORS. When the Company provides Consolidated NGDC Billing, the Company shall not be responsible for billing errors resulting from incorrect information received from an NGS.

16.10 PAYMENT TERMS. The Company will negotiate payment arrangements with Sales Service Customers The Company will also negotiate payment arrangements for customers served under Consolidated NDGC Billing which includes NGS charges. If the NGS is providing Separate NGS Billing (“dual billing”), the Company will not negotiate agreements on behalf of those NGS charges.

RULES AND REGULATIONS - Continued

17. TERMINATION BY THE COMPANY

17.1 NON-PAYMENT SHUT-OFF. On reasonable notice, the Customer is subject to collection action, including termination of service (in accordance with the Pennsylvania Public Utility Code or the Commission's regulations,) on the portion of the past due amount attributable to the Company's charges for service and/or gas commodity. Upon termination of service, the Company may also remove its equipment. Notice that complies with applicable Commission regulations shall conclusively be considered "reasonable hereunder". Consistent with 52 PA Code §56.100, the Company will accept the following most current and valid documents as proof of household income: (1) income tax returns; (2) pay stubs; (3) benefit letters and governmental agency verification; (4) other forms to be accepted at the Company's discretion. The customer must provide this information within 10 days of the Company's request. This information may also be used by the company to determine deposit requirements, payment arrangements, and any other income specific program.

17.2 SHUT-OFF FOR CAUSE. The Company may terminate on reasonable notice if entry to its meter or meters is refused or if access thereto is obstructed or hazardous; or if utility service is taken without the knowledge or approval of the Company; or for other violation of these Rules and/or applicable Commission rules in accordance with the Pennsylvania Public Utility Code or the Commission's regulations.

17.3 SAFETY SHUT-OFF. The Company may terminate without notice if the Customer's installation has become hazardous or defective.

17.4 DEFECTIVE EQUIPMENT SHUT-OFF. The Company may terminate without notice if the Customer's equipment or use thereof might injuriously affect the equipment of the Company, or the Company's service to other Customers.

17.5 SHUT-OFF FOR FRAUD. The Company may terminate without notice for abuse, fraud, material misrepresentation of the customer's identity or tampering with the connections, meters, or other equipment of the Company.

17.6 RECONNECTION CHARGE. If service is terminated or discontinued by reason or act of the Customer, the same Customer, whether an applicant or a customer as defined at 66 Pa. C.S. § 1403, shall pay a reconnection charge, prior to restoration of service at the same address within twelve months after discontinuance or termination. The reconnection charges, listed below, are based on the Company's current standard schedule of reconnection fees, which include direct labor costs, contractor costs, and material/transportation costs.

	Reconnect Fees For Non-Payment
Gas Reconnect at Meter	$80.00
Gas Reconnect at Curb	$70.00

17.7 THEFT INVESTIGATION CHARGE. If the Company establishes that there has been confirmed active theft resulting from tampering with the Company meter on the customer's premises, and the customer is or was a customer as defined at Pa. C.S. § 1403 the customer shall pay a theft investigation charge in addition to any amount that the Company establishes is due for service used, but not registered on the Company's meter. The Company reserves the right to assess theft investigation charges as a precedent to reconnection of service as well as the right to assess a separate reconnection charge as described in Rule 17.6.

	Theft Investigation Fees
Gas Theft at Meter	$400.00

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18. UNFULFILLED CONTRACTS

18.1 NOTICE OF DISCONTINUANCE BY CUSTOMER. Notice to discontinue service prior to the expiration of a contract term will not relieve a Customer from any minimum, or guaranteed, payment under any contract or rate.

18.2 COMPLETION OF TERM. If, by reason of any act, neglect or default of a Customer, the Company's service is suspended, or the Company is prevented from supplying service in accordance with the terms of any contract it may have entered into with the Customer, the minimum charge for the unexpired portion of the contract term shall become due and payable immediately as liquidated damages in lieu of the anticipated returns from the said contract. These liquidated damages may, at the option of the Company, be offset by any estimated revenues from a succeeding Customer at the same location if such exists.

18.3 TEMPORARY SUSPENSION OF SERVICE. A residential or commercial Customer may elect to have service temporarily disconnected at the start of a period of suspension and then reconnected at the end of the period by paying a charge of $115.00. During the period of suspension, the Customer will be relieved of the payment of minimum bills.

RULES AND REGULATIONS - Continued

19. CANCELLATION BY CUSTOMER

19.1 TERMINATION NOTICE. Customers who have fulfilled their initial contract term and wish to discontinue service must give at least 7 days' notice to that effect, unless otherwise provided for in a rate schedule or service agreement.

19.2 FINAL BILL. The Customer is liable for service taken after notice to terminate the contract until the meter is read and gas shut off. The final bill for service is then due and payable within 20 days from the date of transmittal of the bill for residential customers and 15 days for non-residential customers.

19.3 EXIT FEES. A Customer, other than a Low Volume Customer, taking firm sales service that transfers to an interruptible service or to firm Transportation Service without firm standby sales service will be required to continue payment of the firm gas supply demand costs allocable to Customer's firm sales service until the Company is able to reduce its contract demand level or otherwise utilize the contract demand allocable to Customer's firm sales service.

20. GENERAL

20.1 OFFICE OF THE COMPANY. Wherever, in this Tariff, it is provided that notice be given or sent to the Company, or the office of the Company, such notice, delivered or mailed, postage prepaid, to any commercial office, shall be deemed sufficient, unless the Main Office of the Company at 2301 Market Street, Philadelphia, is expressly mentioned.

20.2 NO PREJUDICE OF RIGHTS. The failure by the Company to enforce any of the terms of this Tariff shall not be deemed a waiver of its right to do so.

20.3 GRATUITIES TO EMPLOYEES. The Company's employees are strictly forbidden to demand or accept any personal compensation, or gifts, for service rendered by them while working for the Company on the Company's time.

20.4 BILLING CHANGES. Where billing changes are made as the result of an investigation made at Customer's request or by routine inspection, the change of billing may be applied to the bill for the regular meter reading period preceding such investigation, and will in any event apply to the bill for the period during which the check is made.

20.5 EXCEPTIONAL CASES. Sales and/or Transportation service shall be subject to the provisions of this Tariff; but where special conditions or problems arise for which provision is not otherwise made, the Company may modify or adapt its terms to meet the peculiar requirements of such case, provided that such modified terms are a rational expansion of standard tariff provisions.

20.6 ASSIGNMENT. Subject to the Rules and Regulations, all contracts made by the Company shall be binding upon, and oblige and ensure to the benefit of, the successors and assigns, heirs, executors, and administrators of the parties thereto.

20.7 OTHER CHARGES. Except as where otherwise provided in this tariff the Company may where feasible, provide and charge for services requested by the Customer or his agent. The Company is not obligated to provide such services. The Company will, if possible, give the Customer an advance written estimate of the costs to provide the service.

21. GAS CHOICE PROGRAM ENROLLMENT AND SWITCHING

In accordance with all applicable final Commission Orders:

21.1 All LVT Customers will be eligible to obtain Competitive Natural Gas Supply starting with their first regularly scheduled meter reading after July 1, 2000.

21.2 The Company will send Gas Choice Release of Information packets to all new LVT Customers, which information will provide Customers the opportunity to authorize the release of their confidential account information. PECO annually notifies customers that they can change this authorization. Every three years, in accordance with PUC Docket No. M-2012-2324075, PECO will re-solicit its entire customer base for the purpose of opting out of disclosing information.

21.3 Customers may select a Supplier, as often as monthly, in accordance with Commission Orders and the procedures contained in this Tariff and in the Supplier Coordination Tariff.

21.4 If a Customer, or agent authorized to act on the Customer's behalf, contacts the Company via telephone to select a Supplier, the Company will advise the Customer or agent to contact the selected Supplier to submit the required electronic enrollment file.

21.5 For a Customer's enrollment to become effective on the Customer's next regularly scheduled meter read date, the Supplier must submit the required electronic file at least eleven (11) days prior to said meter read date.

21.6 If, in any month, a Customer selects more than one Supplier, the Supplier that submitted to the Company, before the end of the applicable Supplier selection period, the Supplier enrollment file with the latest valid Supplier contract will become the Customer's Supplier of record.

21.7 The Company will send a confirmation notice to all Customers who have made a Supplier selection by the next business day after receiving the Customer's enrollment file from the Supplier. This confirmation shall include notification of a five (5) day waiting period in which the Customer may cancel its selection of a Supplier. The waiting period shall begin on the date the Company confirmation is mailed to the Customer. If the five (5)-day waiting period expires, and the Customer has not contacted the Company to cancel the Supplier selection, the Supplier will become the Customer's Supplier of record.

21.8 If the Customer elects to cancel its Supplier selection, the Company will notify the rejected Supplier electronically via an approved EDI transaction. In the event the Customer cancels its Supplier selection after the five (5) day waiting period, the Customer will be required to remain with the selected Supplier for a minimum of one billing cycle.

21.9 If at least eleven (11) days prior to the Customer's next regularly scheduled meter read date, a Customer contacts the Company to request a switch from a Supplier to the Company's (SLR) Sales Service, the request will be effective as of that meter read date and the Company as the supplier of-last resort will become the Supplier of record for delivery.

21.10 In the event the Customer requests a switch less than eleven (11) days before the Customer's next regularly scheduled meter read date, the switch will be effective as of the next following meter read date.

21.11 If, other than at the end of a billing cycle, and because of an NGS's default, an NGS terminates sales to a Customer prior to the end of the Customer's contract with the NGS, for gas supply provided through the end of the relevant billing cycle, said Customer will pay the NGS's contract rate in accordance with information filed by the NGS with the Commission.

22. USAGE DATA

At the request of the Customer, or at the request the Customer's designated Supplier or authorized agent, the Company will supply twelve (12) individual months of historical usage data for no charge. Any additional historical information requested will be provided, if available, for a fee of ninety-two dollars ($92.00) per provision.

23. AFFILIATED MARKETER STANDARDS OF CONDUCT

PECO Energy and its affiliated natural gas supplier shall comply with the following requirements:

(1) A natural gas distribution company shall apply its tariffs in a nondiscriminatory manner to its affiliated natural gas supplier and any nonaffiliated natural gas supplier.

(2) A natural gas distribution company shall not apply a tariff provision in any manner that would give its affiliated natural gas supplier an unreasonable preference over other natural gas suppliers with regard to matters such as scheduling, balancing, transportation, storage, curtailment, capacity release and assignment, or non-delivery, and all other services provided to its affiliated natural gas supplier.

(3) Mandatory tariff provisions shall not be waived by a natural gas distribution company for any natural gas suppliers absent prior approval of the Commission.

(4) If a tariff provision is not mandatory or provides for waivers, a natural gas distribution company shall grant the waivers without preference to its affiliated natural gas supplier or non-affiliated natural gas supplier.

(5) A natural gas distribution company shall maintain a chronological log of tariff provisions for which it has granted waivers. Entries shall include the name of the party receiving the waiver, the date and time of the request, the specific tariff provision waived and the reason for the waiver. The chronological log shall be open for public inspection during normal business hours.

(6) A natural gas distribution company shall process requests for distribution services promptly and in a nondiscriminatory fashion with respect to other requests received in the same or a similar period. A natural gas distribution company shall maintain a chronological log showing the processing of requests for transportation services. The chronological log shall be open for public inspection during normal business hours.

(7) If a natural gas distribution company provides a distribution service discount, fee waiver or rebate to its favored customers, or to the favored customers of its affiliated natural gas supplier, the natural gas distribution company shall offer the same distribution service discount, fee waiver or rebate to other similarly situated customers. Offers shall not be tied to any unrelated service, incentive or offer on behalf of either the natural gas distribution company or its affiliated natural gas supplier. A chronological log shall be maintained showing the date, party, time and rationale for the action. The chronological log shall be open for public inspection during normal business hours.

(8) Subject to customer privacy or confidentiality constraints, a natural gas distribution company shall not disclose, directly or indirectly, any customer proprietary information to its affiliated natural gas supplier unless authorized by the customer. To the extent that a natural gas distribution company does disclose customer information without customer authorization, it shall contemporaneously provide this same information to other similarly situated natural gas suppliers in a similar fashion so as not to selectively disclose, delay disclosure, or give itself or its affiliated natural gas supplier any advantage related to the disclosure. A chronological log shall be maintained showing the date, time and rationale for the disclosure. The chronological log shall be open for public inspection during normal business hours.

(9) A natural gas distribution company shall justly and reasonably allocate to its affiliated natural gas supplier the costs or expenses for general administration or support services provided to its affiliated natural gas supplier.

(10) Natural gas distribution companies shall not condition or tie the provision of any product, service or price agreement by the natural gas distribution company (including release of interstate pipeline capacity) to the provision of any product or service by its affiliated natural gas supplier.

(11) A natural gas distribution company shall not give its affiliated natural gas supplier preference over a non-affiliated natural gas supplier in the provision of goods and services including processing requests for information, complaints and responses to service interruptions. Natural gas distribution companies shall provide comparable treatment in its provision of such goods and services without regard to a customer’s chosen natural gas supplier.

(12) A natural gas distribution company and its affiliated natural gas supplier shall maintain separate books and records. Further, transactions between the natural gas distribution company and its affiliated natural gas supplier shall not involve cross-subsidies. Any shared facilities shall be fully and transparently allocated between the natural gas distribution company function and the affiliated natural gas supplier function. The natural gas distribution company accounts and records shall be maintained such that the costs incurred on behalf of an affiliated natural gas supplier may be clearly identified.

(13) Natural gas distribution company employees who have responsibility for operating the distribution system, including natural gas delivery or billing and metering, shall not be shared with an affiliated natural gas supplier, and their offices shall be physically separated from the office(s) used by those working for the affiliated natural gas supplier. Such natural gas distribution company employees may transfer to an affiliated natural gas supplier provided such transfer is not used as a means to circumvent these interim standards of conduct.

(14) Neither the natural gas distribution company nor its affiliated natural gas supplier shall directly or by implication, falsely and unfairly represent to any customer, natural gas supplier or third party that an advantage may accrue to any party through use of the natural gas distribution company's affiliates or subsidiary, such as:

- That the Commission regulated services provided by the natural gas distribution company are of a superior quality when services is purchased from its affiliated natural gas supplier; or

- That the merchant services (for natural gas) are being provided by the natural gas distribution company when they are in fact being provided by an affiliated natural gas supplier;

- That the natural gas purchased from a non-affiliated natural gas supplier may not be reliably delivered;

- That natural gas must be purchased from an affiliated natural gas supplier to receive Commission regulated services.

(15) When affiliated natural gas supplier market or communicate to the public using the natural gas distribution company name or logo, it shall include a legible disclaimer that states:

- That the affiliated natural gas supplier is not the same company as the natural gas distribution company;

- That the prices of the affiliated natural gas supplier are not regulated by the Pa PUC; and

- That a customer does not have to buy natural gas or other products from the affiliated natural gas supplier in order to receive the same quality service from the natural gas distribution company.

When an affiliated natural gas supplier advertises or communicates verbally through radio or television to the public using the natural gas distribution company name or logo, the affiliated natural gas supplier shall include at the conclusion of any such communication a legible disclaimer that includes all of the disclaimers listed in this paragraph.

(16) Except in competitive bid situations a natural gas distribution company shall not (a) jointly market or jointly package its Commission regulated services with the services of an affiliated natural gas supplier or (b) offer or provide to its affiliated natural gas supplier products or services, including bill inserts in its natural gas distribution company bills promoting an affiliated natural gas supplier's services or a link from the natural gas distribution company's web-site, unless the natural gas distribution company offers or provides the products or service to all non-affiliated natural gas supplier on the same terms and conditions.

(17) A natural gas distribution company shall not offer or sell natural gas commodity or capacity to its affiliated natural gas supplier without simultaneously posting the offering electronically on a source generally available to the market or otherwise

making a sufficient offer to the market. The natural gas distribution company shall maintain a chronological log of these public disseminations. The chronological log shall be open for public inspection during normal business hours.

(18) Natural gas distribution companies shall establish and file with the Commission a complaint procedure for dealing with any alleged violations of any of the standards of conduct, with the exception of paragraph (9), which are exclusively under the purview of the Commission. These procedures shall be developed in consultation with interested parties during consideration of any tariff guided by this section and §69.191 (relating to general). The Commission may grant an exception to these requirements if warranted by the facts or circumstances.

(19) A natural gas distribution company shall keep a chronological log of any complaints, excepting paragraph (9), regarding discriminatory treatment of natural gas suppliers. This chronological log shall include the date and nature of the complaint and the resolution of the complaint. The chronological log shall be open for inspection during normal business hours.

(20) Dispute Resolution Procedures: In addition to the procedure set forth in paragraph 18:

- Any dispute between a natural gas supplier, and/or an affiliated natural gas supplier, and a non-affiliated natural gas supplier alleging a violation of any of these Standards of Conduct provisions, the natural gas supplier must provide the natural gas distribution company and/or affiliated natural gas supplier, as applicable, a written Notice of Dispute that includes the names of the Parties and Customer(s), if any, involved and a brief description of the matters in dispute.

- Within five (5) days of a natural gas distribution company's and/or affiliated natural gas supplier's receipt of a Notice of Dispute, a designated senior representative of each of the Parties shall attempt to resolve the dispute on an informal basis.

- In the event the designated representatives are unable to resolve the dispute by mutual agreement within thirty (30) days of said referral, the dispute shall be referred for mediation through the Commission's Office of Administrative Law Judge. A party may request mediation prior to that time if it appears that informal resolution is not productive.

- If mediation is not successful, then the matter shall be converted to a formal proceeding before a Commission Administrative Law Judge.

- Any Party may file a complaint concerning the dispute with the Commission under relevant provisions of the Public Utility Code.

- Parties alleging violations of these standards may pursue their allegations through the Commission's established complaint procedures. A complainant bears the burden of proof consistent with 66 Pa. C.S. §332 (relating to Public Utility Code) in regard to the allegations and may impose penalties for such violations pursuant to 66 Pa.C.S.§ 3301.

(21) A natural gas distribution company shall file a compliance filing within sixty (60) days of the entry of an order approving or modifying a restructuring plan, which sets forth a detailed plan for compliance with this Standard of Conduct as well as the Commission separation and cost allocation requirements already ordered.

(22) Every natural gas distribution company and its affiliated natural gas supplier shall formally adopt and implement these provisions as company policy and shall take appropriate steps to train and instruct its employees in their content and application.

RULES AND REGULATIONS – Continued

24 REQUESTS FOR ENERGY EFFICIENCY INFORMATION

Upon request of a Customer for energy efficiency information, the Company will provide a copy of its then current residential or commercial energy efficiency guide, as applicable.

25. CREDITWORTHINESS OF A NATURAL GAS SUPPLIER (NGS) SERVING HIGH VOLUME TRANSPORTATION CUSTOMERS

(a) Unless a mutual agreement is reached between the Company and a NGS, or other applicable entity as specified in 52 Pa. Code § 62.101 the amount and form of security shall be based on the criteria established in 52 Pa. Code §62.111. In accordance with §62.111, a NGS seeking to deliver natural gas supplies to the Company for the account of one or more of the Company's non-exempt HVT Customers must satisfy at least one of the following financial criteria:

(1) The NGS has a minimum credit rating of 3A2 from Dun & Bradstreet, a minimum bond rating of Baa2 from Moody's, or a rating of BBB from Standard & Poor's, Fitch ICBA or Duff & Phelps; or

(2) The NGS has furnished the Company with an irrevocable and binding form of security (e.g., surety bond, letter of credit, security interest in collateral acceptable to the Company, a corporate guaranty, or a written affirmation of financial support by a parent or affiliated company) issued by an obligor that has a minimum credit rating of 3A2 from Dun & Bradstreet, a minimum bond rating of Baa2 from Moody's, a minimum bond rating of BBB from Standard & Poor's, Fitch ICBA or Duff & Phelps, or, for an insurance company, an A.M. Best credit rating of no less than A-and in which the obligor designates the Company as the sole beneficiary and which otherwise is in a form and amount acceptable to the Company; or

(3) The NGS provides the Company with a cash deposit and/or a cash escrow arrangement in an amount and form acceptable to the Company, and agrees, in a writing furnished to the Company, to be responsible, as between the Company and the Supplier, for the payment of all deficient and excess delivery charges assessed in accordance with the Company's Gas Transportation Service – General Terms and Conditions that are caused by the NGS' excess or deficient deliveries. Such responsibility on the part of the NGS would not relieve the HVT Customer of its responsibility for the payment of the same charges in accordance with the Gas Transportation General Terms and Conditions. If the NGS is determined to have been responsible for the excess/deficient delivery and if the NGS pays the related charges to the Company, then the HVT customer would be relieved of such responsibility.

For the purposes of this subsection (a)**,** the "amount acceptable to the Company" shall be a dollar amount ($US) equal to the monetary value obtained by multiplying 45 days of average daily winter usage for each HVT Customer supplied by the NGS times the then effective Commodity Charge.

(4) The NGS has furnished the Company with an acceptable amount of Security in the form of an escrow account or nets any gas supply sales that the NGS has made to the Company and for which the Company owes payment to the NGS against the amount of Security required. The amount of Security contained in either situation must be in an amount equal to the monetary value obtained by multiplying 45 days of average daily winter usage for each HVT Customer supplied by the NGS times the then effective Commodity Charge.

RULES AND REGULATIONS – Continued

(b) The Company shall have the right to assess each NGS' creditworthiness on an annual basis. As such, the Supplier is required to furnish annual audited financial statements to the Company. In the event the Company does not receive any annual audited financial statements, unaudited financial statements may be acceptable. The Company also may perform more than one financial analysis for any Supplier during the course of the year when the Company reviews financial information of a Supplier and determines, in the Company's judgment that the Supplier's creditworthiness has materially changed.

(c) Unless a mutual agreement is reached, the amount of Security required may be modified based on one or more of the following criteria:

1. The NGS's past operating history on all other NGDC systems, including the duration that the NGS operated on each system, the number of customers served on each system and any supply reliability problems that occurred on each system.
2. An NGS's credit reports.
3. The number and class of customers being served.
4. Information that materially affects a NGS's creditworthiness such as:

a) a change in the NGS's recent operating history on the Company's system or on other NGDC systems that has materially affected NGDC system operation or reliability. Such a change may occur when a Supplier fails to deliver natural gas supply to meet its customers' needs or fails to comply with NGDC operational flow orders as defined at 52 Pa. Code § 69.11;

b) a change in the NGS's credit reports that materially affects its creditworthiness. Creditworthiness could be materially affected when 2 of the following credit rating companies change the Supplier's credit rating:
1. Dun & Bradstreet
2. Standard & Poor's Rating Services Inc.
3. Transunion LLC
4. Equifax Inc.
5. Experian Information Solutions, Inc;

c) a significant change, defined as a 25% change over a 30-day period, in the number and class of customers served, the volume of gas delivered or the average unit price of natural gas;

d) a change in operational or financial circumstances that materially affects a NGS's creditworthiness. This can occur when 2 of the following investment rating companies change the NGS's rating of its issued securities from an investment grade or good rating to a speculative or moderate credit risk rating and vice versa:
1. Standard & Poor's Rating Services Inc.
2. Moody's Investment Service, Inc.
3. Fitch, Inc.
4. A.M. Best Company, Inc.
5. DBRS, Inc.;

e) a change in the NGS's demonstrated capability to provide the necessary volume of natural gas to meet its customers' needs that materially affects the Company's system operation or reliability. Such a change may occur when the NGS fails to deliver natural gas supply sufficient to meet its customers' needs on 5 separate occasions within a 30-day period or fails to comply with the Company's operational flow orders.

RULES AND REGULATIONS – Continued

5. The NGS's demonstrated capability to provide the volume of natural gas necessary to meet its customers' needs.

(d) After it is reasonably determined by the Company that an adjustment to the amount of Security provided by the Supplier is required, the Company will adjust the Security amount in accordance with subsection (a)(3).

(e) The NGS shall have the affirmative obligation to inform the Company in writing of any material change in its financial condition in a timely manner.

(f) Notwithstanding anything to the contrary stated in this Rule 25, an NGS shall not be creditworthy if, for any reason, it owes a past due amount to the Company that is not subject to a good faith billing dispute and the payment has not been received by the Company within two business days after the Company has provided a past due notice, or if so determined by order of the Pennsylvania Public Utility Commission.

(g) When the Company determines that a Security adjustment is required, it will provide written notice to the NGS. The NGS shall comply with the Company's determination within 5 business days after the NGS is served with such notice. If the NGS disagrees with the Company's determination, it shall file a dispute in accordance with subsection (h). However, the NGS is still required to post the full amount of adjusted Security requested by the Company within 5 business days after the NGS is served with the Company's notice.
An NGS also may request, in writing, that the Company adjust its Security amount according to the criteria set forth in subsection (c). The Company will provide a written response to the NGS within 5 business days after receipt of the written request from the NGS. In the event that the Company agrees with the NGS's request, the NGS shall post the Security adjustment within 5 business days after the NGS is served with the Company's determination. In the event that the NGS disagrees with the Company's determination, it may file a dispute in accordance with subsection (h). However, if the Company requires an adjustment of Security, the NGS is still required to post the full amount of adjusted Security within 5 business days after the NGS is served with the Company's notice.

(h) An applicant, licensee or NGS shall notify the Company in writing of any dispute(s) it may have regarding the form and amount of Security or the adjustment of Security requested by the Company. If a resolution cannot be reached within 30 days after the Company receives the written notice, the applicant, licensee or NGS may do any of the following:

1. Request that the Secretary of the PUC initiate an informal mediation and resolution process. If the NGS is dissatisfied with the PUC's decision at the informal level, it may petition to appeal the decision or file a Formal Complaint.
2. File a Formal Complaint at the Commission.
3. File a Petition challenging the criteria used by the Company to determine the form and amount of Security requested or the Security adjustment amount.

If a NGS initiates a dispute or files a complaint related to an adjustment in Security by the Company, the following requirements exist during the pendency of the dispute:

1. The NGS is required to provide and maintain the full adjusted Security amount to the Company until the dispute is resolved.
2. The NGS must continue to operate in accordance with the Company's system operations and business rules and practices.
3. The NGS must continue to deliver natural gas volumes necessary to fulfill customer needs and provide customer support services.
4. The Company shall allow the NGS to continue to operate on the Company's system.

RULES AND REGULATIONS – Continued

26. GAS QUALITY STANDARDS: Quality of Gas Delivered to the Company

A. Terms Defined. The following definitions shall apply throughout the Gas Quality Standards sections of this Tariff.

Biogas is a mixture of naturally produced gases resulting from the decomposition of organic matter under anaerobic conditions (in an oxygen-free environment). The principal constituents are methane and carbon dioxide.

Interconnect or interconnection is the physical connection between the Company's natural gas system and the physical equipment of another natural gas system associated with the interconnection point, which may include the interconnection metering, pressure control, filtration and odorization equipment.

Renewable Natural Gas (RNG) is a term used to describe Biogas that has been upgraded for use in place of fossil natural gas. The Biogas used to produce RNG may come from a variety of sources, including municipal solid waste landfills, digesters at water resource recovery facilities (wastewater treatment plants), livestock farms, food production facilities, and organic waste management operations.

RNG Counterparty is any individual, entity, Customer, or otherwise-described party that executes a Renewable Natural Gas agreement with the Company for purposes of injecting, transporting, using, or otherwise introducing or causing RNG to be introduced into the Company's natural gas system. This definition includes RNG producers and/or production facilities.

B. Quality of Gas at Point(s) of Receipt with an Interstate Pipeline.

Natural gas delivered by or caused to be delivered on behalf of Customer to the Company at point(s) of receipt with an interstate pipeline shall conform to the quality specifications of the pipeline(s) used to transport natural gas.

C. For Quality of Gas at Point(s) of Receipt for Renewable Natural Gas.

Gas Quality Standards are specifications meant to ensure that the RNG entering the Company's natural gas system will be interchangeable with the natural gas that the Company currently distributes and will not damage the Company's or the Company's customers' equipment. RNG being injected into the Company's natural gas system shall conform to the following quality specifications at the time of receipt at the interconnection point. With advance notice from RNG Counterparty in writing, the Company may allow deviations from these standards on a case-by-case basis at its sole discretion. With notice to RNG Counterparty in writing, the Company may require adherence to additional specifications, for good cause as determined by the Company on a case-by-case basis at its sole discretion.

C.1 General Specifications:

(a) The Company's interconnection equipment will have automatic and remote shut-off capabilities to ensure the following constituents and standards can be adequately monitored at the point of interconnection and the safety and reliability of the Company's natural gas system protected. The Company may temporarily discontinue the receipt of RNG without notice if it does not conform to the following specifications.

The following constituents and values will be monitored by the Company via chromatograph or other such measurement device as the Company may employ and will be monitored on a regular basis as the Company may determine from time to time (i.e., hourly):

(i) **Heating Value**: The following minimum and maximum heating values apply, both measured on a dry basis at a temperature of sixty degrees Fahrenheit (60° F) and a pressure of 14.73 pounds per square inch absolute (PSIA)—the minimum heating value is 970 Btu (gross) per standard cubic foot (SCF) and the maximum heating value is 1070 Btu (gross) per SCF.

(ii) **Delivery Temperature**: The RNG delivery temperature is not to be below fifty degrees Fahrenheit (50° F) or above one hundred and twenty degrees Fahrenheit (120° F).

(iii) **Methane:** The gas shall contain a minimum of 95% Methane.

(iv) **Propane**: The gas shall contain a maximum of 20% Propane.

(v) **Hydrogen Sulfide:** The gas shall contain no more than 0.5 grains per 100 SCF.

(vi) **Total Sulfur**: The gas shall contain no more than 5 grains per 100 SCF total sulfur. This includes Carbonyl Sulfide (COS) and Carbon Disulfide (CS_2), hydrogen sulfide, mercaptans, and mono, di- and poly-sulfides.

(vii) **Carbon Dioxide and Nitrogen**: The gas shall contain no more than 2% by volume of carbon dioxide (CO_2), not more than 3% by volume of nitrogen (N_2), and shall contain no more than 5% by volume of combined nonhydrocarbon gases including, but not limited to, CO2, N2, and O_2.

(viii) **Hydrogen:** The gas shall contain no more than 0.1% by volume of hydrogen.

(ix) **Oxygen:** The gas shall not contain in excess of 0.3% by volume of oxygen, and the parties agree to exercise every reasonable effort to keep the gas completely free of oxygen.

RULES AND REGULATIONS – Continued

(x) **Hydrocarbons:** The RNG hydrocarbon dew point is not to exceed forty-five degrees Fahrenheit (45^{O} F) at the delivery pressure.

(xi) **Water Vapor:** The gas shall not contain in excess seven (7) pounds (lbs.) of water vapor/1mcf.

C.2 RNG Constituents:

(a) RNG Counterparty shall complete laboratory testing, as described in Section C.3, for the trace constituents listed in the following table. If testing results do not meet the standards listed in the table below, the Company may temporarily interrupt RNG service as outlined in Section C.4.

Parameter	Symbol	Level (max unless noted otherwise)	Units
Siloxanes	Si	5	Mg Si/m³
Hydrogen	H_2	0.1	% vol
Ammonia	NH_3	0.00%	Mol%
Mercury	Hg	0.08	mg/m³
Arsenic	As	0.19	mg/m³
Copper	Cu	0.6	mg/m³
Oxygen	O_2	0.3	% vol
Propane	C_3H_8	20	% vol
Nitrogen	N_2	3	% vol
Methane	CH_4	95	% vol
Hydrogen Sulfide	H_2S	0.5	Grains per 100 SCF
Carbon Dioxide	CO_2	2	% vol
Carbon Monoxide	CO	0.1	% vol
Volatile Organic Compounds	VOCs	5	PPM
Moisture or Water Content	H_2O	7	Pounds per million cu ft
Total Sulfur	S	5	Grains per 100 SCF

(b) Additional Quality Requirements:

(i) **Wobbe Index**: The RNG shall have a minimum Wobbe Number of 1255 Btu/ft^3 and shall not have a maximum Wobbe Number greater than 1375 Btu/ft^3.

(ii) **Dust, Gums, etc.**: The gas shall be free of objectionable odors, dust, gum, dirt, impurities and other solid or liquid or hazardous matter which might interfere with proper operation of the facilities, lines, regulators, meters or other appliances through which it flows. Filters shall be installed on the RNG Counterparty's equipment (i.e., the supply side) to catch any debris.

RULES AND REGULATIONS – Continued

(iii) **Bacteria:** The gas and any associated liquids shall not contain any active bacteria or bacterial agent capable of contributing to or causing operational problems.

C.3 Testing Requirements:

(a) To ensure adherence to the Gas Quality Standards, testing required under this section will be performed by RNG Counterparty using independent, certified third-party laboratories. The Company shall be notified at least five (5) calendar days in advance of the RNG sampling and tests and have the option to observe the samples being taken. Test results will be shared with the Company within five (5) calendar days of the test results being received by RNG Counterparty. Unless otherwise noted herein, the costs associated with the required testing shall be paid by RNG Counterparty.

In its discretion, the Company may, at its own cost and expense, collect samples for testing at the utility meter at the point of interconnection. Re-testing shall be allowed to verify and validate the results of any test. The cost of retesting shall be paid by the entity requesting the retest.

(b) **RNG Pre-Interconnection Testing:** Prior to the injection of RNG into the Company's natural gas system, RNG Counterparty shall conduct two (2) tests over a two (2)-to four (4)-week period for the Gas Quality Standards. If during pre-injection testing, the RNG is found to be non-compliant with the Gas Quality Standards, RNG Counterparty shall make necessary modifications to reduce constituent levels and restart pre-interconnection testing. Connection to the Company's natural gas system is subject to successfully passing these two (2) tests.

(i) **RNG Periodic Testing:** The Company will require RNG Counterparty to conduct periodic testing for the Gas Quality Standards on a quarterly basis (at least once in every three-month period).

C.4 Temporary Discontinuance of Gas Receipt:

(a) **Temporary Discontinuance:** The Company reserves the right to temporarily discontinue the receipt of gas on an immediate basis whenever the RNG is non-compliant with any of the specifications as detailed in the Gas Quality Standards and, as applicable, an RNG agreement, whenever there is an imminent safety risk (including any risk stemming from either Company or RNG Counterparty-owned facilities or equipment), or whenever Company reasonably determines it is necessary to maintain system integrity.

(i) The Company may temporarily disconnect RNG equipment from the Company's natural gas system in the event of an emergency condition as determined by the Company, for scheduled maintenance, construction or repair, or if it is reasonably determined to be necessary in order to maintain the safety and reliability of its system.

(ii) The Company shall notify RNG Counterparty promptly when it becomes aware of an emergency condition or any other condition that that may reasonably be expected to affect RNG Counterparty's operation of its RNG production facility. RNG Counterparty shall notify the Company promptly when it becomes aware of an emergency condition or any other condition that may reasonably be expected to affect the Company's natural gas system. To the extent information is known, the notification shall describe the emergency condition, the extent of the damage or deficiency, the expected effect on the operation of both parties' facilities and operations, its anticipated duration, and the necessary corrective action.

(iii) In the event the Company temporarily discontinues the receipt of RNG for any reason, RNG Counterparty is responsible for ceasing production or diverting RNG from the point of interconnection, as applicable.

(iv) The Company and the RNG Counterparty shall provide five (5) business days' notice prior to temporarily interrupting service for scheduled maintenance, construction, or repair. The Company shall use reasonable efforts to coordinate such temporary disconnection with RNG Counterparty.

(v) The Company and RNG Counterparty shall cooperate with each other to restore any production facility, interconnection facilities, and the Company's natural gas system to their normal operating state as soon as reasonably practicable following any disconnection pursuant to this section, as long as the safety and reliability of the Company's natural gas system is ensured, including ensuring that all Gas Quality Standards are met. During a temporary discontinuance of service, RNG Counterparty shall still be charged the Customer Charge.

(vi) The Company shall not be liable, under any circumstances or in any respect, to RNG Counterparties or any other person or entity for damages arising either directly or indirectly from temporary discontinuance of service.

(b) **Restart Procedures:**
(i) To restart RNG injection following a temporary discontinuance, RNG Counterparty will complete a minimum of one (1) test of the RNG in accordance with the testing requirements specified above. Injection may then resume if the test indicates the RNG complies with the Gas Quality Standards. This test must be reviewed and approved by both the Company and RNG Counterparty.

(ii) To restart RNG injection following a shut-off resulting from above concerns, RNG Counterparty shall notify the Company and may begin injections only once the Company has given approval.

(iii) When the Company's crews are required on-site to restart the RNG injection, including but not limited to on-site testing, the Company has the right to require the associated RNG Counterparty to bear all costs required for such activities, including but not limited to materials, transportation, labor, and overhead.

(iv) The Company and RNG Counterparty may agree to modify the restart procedures identified in this Section on a case-by-case basis, upon written agreement between each party.

RULES AND REGULATIONS – Continued

C.5 Changes Impacting Gas Quality:

The Company must be notified as soon as possible of any substantive expected change to the feedstock, raw gas quality or conversion process that has the potential to impact RNG quality, so that the Company can review whether any action is required including, but not limited to, additional testing, new or revised Gas Quality Standards or a suspension of the receipt of RNG into the Company's natural gas system.

STATE TAX ADJUSTMENT CLAUSE

In addition to the net charges provided for in this Tariff, **a value of 0.03%** will apply to all service on and after January 1, 2026. **(C)**

Whenever any of the tax rates used in the calculation of the surcharge are changed, the surcharge will be recomputed as prescribed by the Commission. The recalculation will be submitted to the Commission within ten days after the tax rates change occurs and the effective date shall be ten days after filing.

In addition, if a recalculation is submitted as a result of a tax rate change, the Company will thereafter file each year on December 21 annual updates with the Commission which will reflect only this tax change. These annual updates will be effective ten days after filing and will continue until such as the effect of the change in tax rates has been included in base rate.

(C) Denotes Change

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC)

Variable Distribution Service Charge rates for gas service in Residential Rate Schedule GR of this Tariff shall include a **credit** of $0.0043 per Mcf (1,000 cubic feet) for recovery of Universal Service Fund Cost (USFC), calculated in the manner set forth below. The USFC rate for gas service shall be increased or decreased annually, to reflect changes in the level of Universal Service Fund costs, net of base rate recoveries, in the manner described below: **(D)**

COMPUTATION OF USFC.

The USFC per Mcf ($x.xxxx), shall be computed in accordance with the formula set forth below:

$$\textbf{USFC} = \frac{\textbf{(C-E-I)}}{\textbf{(S)}}$$

The USFC, so computed, shall be included in distribution rates charged to Customers for service pursuant to the rate schedule identified above. The amount of USFC, per Mcf, will vary, if appropriate, based upon annual filings by the Company.

In computing the USFC, per Mcf, pursuant to the formula above, the following definitions shall apply:

"Reconcilable Customer Assistance Program (CAP) Costs" – The difference between discounts provided to CAP customers (CAP revenue shortfalls) recovered through base rates and total CAP discounts, net of a 27% offset factor.

USFC – Universal Service Fund Charge determined to the nearest one-hundredth cent (0.01¢) to be included in the rate for each Mcf of Variable Distribution Service Charge calculated under Rate Schedule GR, to recover or refund Reconcilable CAP Costs and other items as addressed in the "E" factor.

C - Cost in dollars of the Reconcilable CAP Costs for the projected period.

E - the net (overcollection) or undercollection of Universal Service Fund Charges. The net overcollection or undercollection shall be determined for the most recent period, beginning with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. Included in the "E" factor will be Reconcilable CAP Costs, and up to $1,400,000 of LIURP expenditures above the $2.25 million threshold included in base rates. Also included in the "E" Factor will be any rate credit due customers to the extent PECO expends less than $3,077,500 annually in its Energy Efficiency Plan effective January 1, 2025.

Each overcollection or undercollection statement shall also provide for refund or recovery of amounts necessary to adjust for overrecovery or underrecovery of "E" factor amounts under the previous USFC.

I – Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the period such overcollection is refunded or undercollection is recouped. The interest calculation will not apply to the LIURP amounts.
"

S - projected Mcf of gas service to be billed under Rate GR (exclusive of CAP Rider) during the projected period when rates will be in effect. Mcf's shall be consistent with the projected residential throughput used in the applicable Purchased Gas Cost filing.

FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECONCILIATION.

The Company's annual USFC filing and its annual reconciliation statement shall be submitted to the Commission 120 days prior to new rates being effective December 1 of each year, or at such time as the Commission may prescribe. The USFC mechanism is subject to annual audit review by the Bureau of Audits.

(D) Denotes Decrease

SALES SERVICE COSTS (SSC) - Section 1307(f)

PROVISIONS FOR RECOVERY OF GAS COSTS RELATED TO SALES SERVICE

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Commodity Charge (CC) at **$6.3278** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, **$6.3083** per Mcf for Rate Schedules GC and **$6.2988** **(I)** per Mcf for Rate Schedules OL, L and MV-F for recovery of gas costs related to Sales Service, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code as well as procurement costs as reflected in the Gas Procurement Charge ("GPC") and uncollectable charge-offs as reflected in the Merchant Function Charge ("MFC"). In addition, the Gas Cost Adjustment Charge (GCA) in the amount of **$0.4023** per Mcf will be applicable to customers served under the above mentioned Rate Schedules. Such rates **(I)** for Sales Service gas shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of gas costs related to Sales Service.

COMPUTATION OF CC AND GCA PER MCF.

The CC and GCA, per Mcf, shall be computed to the nearest one-hundredth cent (0.01¢) in accordance with the formulas set forth below:

$$CC = \frac{(C)}{(S)} \times \frac{1}{(1 - T)} + GPC + MFC \quad \text{; and}$$

$$GCA = \frac{(E)}{(S)} \times \frac{1}{(1 - T)}$$

For March 1, June 1 and September 1 quarterly updates, CC is revised to:

$$CC = \left(CC1 + \frac{O}{S1} + \frac{C1)}{S2}\right) \times \frac{1}{(1-T)} + GPC + MFC$$

The CC and GCA so computed, shall be applicable to Customers receiving Sales Service pursuant to the rate schedules identified above. The CC and GCA, per Mcf, will vary, if appropriate, based upon annual filings by the Company pursuant to Section 1307(f) of the Public Utility Code and such supplemental filings as may be required or be appropriate under Section 1307(f) or the Commission's regulations adopted pursuant thereto.

In computing the Charges, per Mcf, pursuant to the formulas above, the following definitions shall apply:

"CC" - Purchased Gas Costs determined to the nearest one-hundredth cent (0.01¢) to be charged for each Mcf of-Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

"C" - Cost in dollars: (a) for all types of purchased gas, project the commodity and all non-storage interstate pipeline costs for each purchase (adjusted for net current gas stored) for the projected period when rates will be in effect; plus (b) the cost of gas provided from storage and LNG facilities, less (c) the new monthly cash-out result determined pursuant to Rule 10.11.3, or the successor thereto, of the Gas Choice Supplier Coordination Tariff .

"C1" - defined as the difference between the current projection of "C" and the projection of "C" used to establish the rates effective December 1 for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"CC1" – defined as the Commodity Charge rate effective December 1 of the current PGC period.

"O" – defined as the difference between the current net over/under collections and the associated projected net over/under collections from the applicable PGC rate calculation, as defined by Commodity Charge revenues less associated gas costs, from December 1 of the current PGC year through the end of the month before the applicable quarterly rate change.

GCA - the "E" factor component of the CC, representing the net overcollection or undercollection of Purchased Gas Costs. Applicable to Sales Service and determined to the nearest one-hundredth cent (0.01¢) for service provided under Rate Schedules GR, GC, CAP, OL, L, and MV-F of this Tariff.

"E" - the net (overcollection) or undercollection of Purchased Gas Costs applicable to the CC.

The net overcollection or undercollection shall be determined for the most recent period permitted under law, which shall begin with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. The annual filing date shall be the date specified by the Commission for the Company's Section 1307(f) tariff filing.

Supplier refunds received after July 1, 2001 associated with Commodity Charges will be included in the calculation of "E" with interest added at the annual rate of six percent (6%) beginning with the month such refund is received by the Company.

(I) Denotes Increase

"GPC" – Gas Procurement Charge determined to the nearest one-hundredth cent (0.01¢) to be charged for each Mcf of Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L, and MV-F of this Tariff.

"MFC" – Merchant Function Charge determined to the nearest one hundredth cent (0.01¢) to be charged for each Mcf of Sales Services gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

Each overcollection or undercollection statement shall also provide for refund or recovery of amounts necessary to adjust for overrecovery or underrecovery of "E" factor amounts under the previous 1307(f) GCA.

Interest shall be computed monthly at the prime rate for commercial borrowing in effect sixty days prior to the tariff filing in accordance with Section 1307(f) of the Public Utility Code as modified by PA Act 47. The interest rate will be based on that reported in the Wall Street Journal. Interest will be computed from the month that the overcollection or undercollection occurs to the effective month such overcollection is refunded or undercollection is recouped. The interest rate basis will become effective with the December 2016 billing cycle

"S" projected Mcf of gas to be billed to Customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L & and MV-F during the projected period when rates will be in effect.

"S1" - defined as the applicable twelve month mcf sales billed to customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L, and MV-F.

"S2" – defined as mcf sales billed to customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L, and MV-F and for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"T" the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

"Purchased Gas Costs" - Include the direct costs paid by the Company for the purchase and delivery of natural gas (which also includes liquefied natural gas, synthetic natural gas, and natural gas substitutes, excluding propane, the cost of which is included in the Balancing Service Costs) to its system to supply its Customers (plus such portion of the Company's used and unaccounted for gas as the Commission permits), including costs paid under agreements to purchase natural gas from sellers; costs paid for transporting natural gas to its system; all charges, fees, taxes and rates paid in connection with such purchases, pipeline gathering, and transportation; and costs paid for employing futures, options and other risk management tools.

QUARTERLY UPDATES

The Company's rates for recovery of gas costs related to Sales Service are also subject to quarterly adjustments under procedures set forth in Section 1307 (f) of the Public Utility Code and in the Commission's regulations. Such updates shall reflect, adjustments for under or overcollections and, adjustments to the projected cost of gas related to Sales Service based upon more current versions of the same sources of data and using the same methods to project the gas costs related to Sales Service approved by the Commission in the Company's most recent annual proceeding for recovery of gas costs related to Sales Service under section 1307 (f).

OFF-SYSTEM SALES SHARING MECHANISM

The rate for Sales Service gas as determined above shall be adjusted to reflect the operation of the off-system sales sharing mechanism set forth herein. Revenues received by PECO Energy from third party storage management services and revenues from exchanges or swaps of gas, excluding the Customer's share of such revenue attributable to use or management of storage or related storage transportation capacity by customers not connected to the Company's system (which revenue shall be included in the Balancing Service Costs E factor, shall be included as off-system sales revenues). Effective April 1, 2001 through March 30, 2008 PECO Energy will be permitted to retain 25% of off system sales margin revenues up to the first $3.5 million in margin revenues, and PECO Energy will be permitted to retain 30% of off system sales margin revenues for margin revenues over $3.5 million. Subsequently, effective March 31, 2008 through November 30, 2028 and thereafter, until terminated or otherwise revised by Final Order **(C)** of the Commission, PECO Energy will be permitted to retain 25% of off-system sales margin revenues. PECO Energy's share shall be computed on a pre-income tax basis, "below the line" for ratemaking purposes. The remaining off-system sales margin will be credited to the recovery of purchased gas costs. Margin revenues derived from sales of gas which is taken from system supply are defined as the unit revenue less the monthly weighted average commodity cost of gas, less any applicable taxes other than income taxes. Margin revenues derived from specific purchase sales (sales where a specific gas supply has been purchased to make a sale) shall be defined as the unit revenue less the specific purchase commodity cost of gas, less any applicable taxes other than income taxes. Specific purchase sales will have no impact on the cost of system supply. Off-system sales for operational purposes such as for meeting mandatory storage withdrawals are excluded from the mechanism. The calculations under this mechanism shall be subject to audit and to review in annual 1307(f) proceedings.

SALES SERVICE COSTS (SSC) - Section 1307 (f) - Continued

FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECTIFICATION.

The Company's annual Section 1307(f) filing or its annual reconciliation statement shall be submitted to the Commission by June 1 of each year, or such other time as the Commission may prescribe by order or by regulation.

The Company shall notify the Commission of any change in the price of purchased gas from any supplier, which change would cause an increase or decrease of more than one per cent (1%) in the "C" factor, defined above. Such notification will be given within thirty (30) days after the effective date of such change in price, or as soon as reasonably practical thereafter.

GAS PROCUREMENT CHARGE

PROVISIONS FOR RECOVERY OF GAS PROCUREMENT CHARGES

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Gas Procurement Charge ("GPC") at **$0.0360** per Mcf (1,000 cubic feet) for recovery of gas procurement costs related to Sales Service, calculated in the manner set forth below and pursuant to the Final Orders at Docket No. P-2012-2328614 and Docket No. R-2024-3046932.

The GPC will be included in the Company's Commodity Charge ("CC") and the Price to Compare ("PTC").

COMPUTATION OF GAS PROCUREMENT CHARGE

The GPC shall include gas procurement costs incurred by the Company on behalf of its Sales Service customers. The GPC shall include the following costs:

1. Natural gas supply service, acquisition and management costs, including natural gas supply bidding, contracting, hedging, credit, risk management costs and working capital.
2. Administrative, legal, regulatory and general expenses related to those natural gas procurement activities, excluding those related to the administration of firm storage and transportation capacity.

The GPC shall be computed as follows:

GPC = GPCC/S x 1/(1-T)

"GPCC" – applicable gas procurement costs as defined in Items 1 and 2 above.

"S" – defined as twelve months of Mcf sales billed to customers receiving Sales Service under Rate Schedules GR CAP, GC, OL, L, and MV-F.

"T" – the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

The costs for the GPC shall remain in effect until reviewed and updated in each base rate case filed by the Company. The calculation of the GPC shall be updated in conjunction with updates in costs for the GPC. The GPC shall not be subject to reconciliation for any prior period over or under collections.

MERCHANT FUNCTION CHARGE

PROVISIONS FOR RECOVERY OF MERCHANT FUNCTION CHARGES

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP GC, OL, L and MV-F shall include the Merchant Function Charge ("MFC") at **$0.0296** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, at **$0.0101** per Mcf for Rate Schedule GC and at **$0.0006** per Mcf for Rate Schedules OL, L and MV-F for recovery of gas uncollectible charge-offs related to Sales Service, calculated in the manner set forth below and pursuant to the Final Order at Docket No. P-2012-2328614 and at Docket No. R-2024-3046932. The MFC will be included in the Company's Commodity Charge ("CC") and the Price to Compare ("PTC") and shall be updated quarterly in conjunction with the calculation of the CC. **(I)**

COMPUTATION OF MERCHANT FUNCTION CHARGE

The MFC shall include uncollectible charge-offs incurred by the Company on behalf of its Sales Service customers and calculated for Rate Schedules GR, CAP, GC, OL, L and MV-F. The MFC shall be computed as follows:

MFC = Write-Off Factor x CCEMFC x 1 / (1 – T)

"Write-Off Factor" - the write-off factors for Rate Schedules GR and CAP **(0.47%),** Rate Schedule GC **(0.16%)** and Rate Schedules OL, L and MV-F (**0.01%)** as determined at Docket No R-2024-3046932, the Company's 2024 gas base rate case. The write-off factors shall be updated as part of future base rate cases.

"CCEMFC" – the applicable quarterly CC including the GPC and excluding the MFC.

"T" – the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

The calculation of the MFC shall be updated in conjunction with changes in the CC including the GPC and excluding the MFC and updates in the write-off factors. The MFC shall not be subject to reconciliation for any prior period over or under collections.

PRICE TO COMPARE

The Price to Compare ("PTC") is comprised of the Commodity Charge ("CC"), the Gas Cost Adjustment ("GCA"), the Gas Procurement Charge ("GPC") and the Merchant Function Charge ("MFC"). The Commodity Charge includes the Gas Procurement Charge and the Merchant Function Charge. The PTC will change whenever any components of the PTC change. The current PTC's are detailed below:

COMPONENT	**RATES GR and CAP**	
Commodity Charge excluding GPC and MFC	$6.2622 per Mcf	**(I)**
Gas Cost Adjustment	$0.4023 per Mcf	**(I)**
Gas Procurement Charge	$0.0360 per Mcf	
Merchant Function Charge	$0.0296 per Mcf	**(I)**
Price to Compare	$6.7301 per Mcf	**(I)**

COMPONENT	**RATES GC**	
Commodity Charge excluding GPC and MFC	$6.2622 per Mcf	**(I)**
Gas Cost Adjustment	$0.4023 per Mcf	**(I)**
Gas Procurement Charge	$0.0360 per Mcf	
Merchant Function Charge	$0.0101 per Mcf	**(I)**
Price to Compare	$6.7106 per Mcf	**(I)**

(I) Denotes Increase

COMPONENT	RATES OL, L and MV-F	
Commodity Charge excluding GPC and MFC	$6.2622 per Mcf	**(I)**
Gas Cost Adjustment	$0.4023 per Mcf	**(I)**
Gas Procurement Charge	$0.0360 per Mcf	
Merchant Function Charge	$0.0006 per Mcf	**(I)**
Price to Compare	$6.7011 per Mcf	**(I)**

(I) Denotes Increase

BALANCING SERVICE COSTS (BSC)- Section 1307(f)

PROVISIONS FOR RECOVERY OF BALANCING SERVICE COSTS.

Rates for Balancing Service for all gas delivered under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall be charged at **$0.3829** per Mcf (1,000 cubic feet) for recovery of those costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. Such rates for Balancing Service shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of Balancing Service Costs. **(I)**

COMPUTATION OF BALANCING SERVICE COSTS PER MCF

Balancing Service Costs, per Mcf, shall be computed to the nearest one-hundredth cent (0.01¢) in accordance with the formula set forth below:

$$BSC = \frac{(C - E)}{(S)} \quad X \quad \frac{1}{(1 - T)}$$

For March 1, June 1 and September 1 quarterly updates, the BSC is revised to:

$$BSC = \left(CC1 + \frac{O}{S1} + \frac{C1}{S2} - \frac{E}{S1}\right) \times \frac{1}{(1 - T)}$$

Projected Balancing Service Costs, so computed, shall be charged to Customers for all gas delivered pursuant to the rate schedules identified above. The amount of those costs, per Mcf, will vary, if appropriate, based upon annual filings by the Company pursuant to Section 1307(f) of the Public Utility Code and such supplemental filings as may be required or be appropriate under Section 1307(f) or the Commission's regulations adopted pursuant thereto.

In computing the Balancing Service Costs, per Mcf, pursuant to the formula above, the following definitions shall apply:

"BSC" - Balancing Service Costs determined to the nearest one-hundredth cent (0.01¢) to be charged to each Mcf of gas delivered under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

"C" - Cost in dollars: for all types of storage and related services, project the cost for the projected period when rates will be in effect.

"C1" - defined as the difference between the current projection of "C" and the projection of "C" used to establish the rates effective December 1 for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"CC1"- defined as the rate associated with "C" effective December 1 of the current PGC period.

"O" – defined as the difference between the current net over/under collections and the associated projected net over/under collections from the applicable PGC rate calculation, as defined by storage and related services revenues less associated storage and related services costs from December 1 of the current PGC year through the end of the month before the applicable quarterly rate change.

"E" - the net overcollection or undercollection of Balancing Service Costs.

The net overcollection or undercollection shall be determined for the most recent period permitted under law, which shall begin with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. The annual filing date shall be the date specified by the Commission for the Company's Section 1307(f) tariff filing.

Each overcollection or undercollection statement shall also provide for refund or recovery of amounts necessary to adjust for overrecovery or underrecovery of "E" factor amounts under the previous Balancing Service Costs Rate.

Interest shall be computed monthly at the prime rate for commercial borrowing in effect sixty days prior to the tariff filing in accordance with Section 1307(f) of the Public Utility Code as modified by PA Act 47. The interest rate will be based on that reported in the Wall Street Journal. Interest will be computed from the month that the overcollection or undercollection occurs to the effective month such overcollection is refunded or undercollection is recouped. The interest rate basis will become effective with the December 2016 billing cycle.

As otherwise described in the Sales Service Costs section "Off-System Sales Sharing Mechanisms", the portion of margin revenue attributable to certain balancing assets shall be included in the calculation of "E".

Supplier refunds received prior to July 1, 2001 will be included in the calculation of "E" with interest added at the annual rate of six per cent (6%) beginning with the month such refund is received by the Company.

"S" - projected Mcf of gas to be delivered to Customers during the projected period when rates will be in effect.

"S1" - defined as the applicable twelve months of mcf of gas to be delivered to customers.

"T" - the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

"S2" – defined as mcf sales delivered to customers for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"T" - the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

Balancing Service Costs - fixed and variable storage costs and the cost of propane to be charged to all customers served under Rate Schedules GR, CAP, GC, OL, L, and MV-F of this Tariff.

QUARTERLY UPDATES

The Company's rates for recovery of Balancing Service Costs are also subject to quarterly adjustments under procedures set forth in the Commission's regulations at 52.Pa. Code 53.64 (1) (5). Such updates shall reflect adjustments for under or over collections and adjustments to the projected cost of Balancing Services based upon more current versions of the same sources of data and using the same methods to project the Balancing Service Costs approved by the Commission in the Company's most annual proceeding for recovery of Balancing Service Costs under section 1307 (f) of the Public Utility Code.

(I) Denotes Increase

FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECTIFICATION.

The Company's annual Section 1307(f) filing or its annual reconciliation statement shall be submitted to the Commission by June 1 of each year, or such other time as the Commission may prescribe by order or by regulation.

Consumer Education Charge (CEC)

PROVISIONS FOR RECOVERY OF CONSUMER EDUCATION COSTS

Purpose - The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's approved gas consumer education costs.

Applicability - The surcharge shall be charge calculated to the nearest one-hundredth cent (0.01¢), which shall be added to the Variable Distribution rates for all Low Volume Customers for recovery of Consumer Education Costs associated with Gas Choice. The rate shall be calculated separately for each customer class. The current Consumer Education Plan Cost for each Class 1 is $0.0013 per Mcf for Rates GR and CAP, Class 2 is $0.0000 per Mcf for Rate GC and for Class 3 is $0.0000 per Mcf for Rates L and MV-F. **(I)**

COMPUTATION OF CEC
The CEC per MCF shall be calculated on an annual basis using the following formula:

$$CEC(n) = \frac{(C+E+I)}{S(n)}$$

In computing the CEC, pursuant to the formula above, the following definitions shall apply:

C – the cost of the consumer education program includes the following:

Consumer Education Cost: Costs attributable to the Company's payment of the Commission's Statewide Education Assessment and all incremental external and incremental internal costs of the Company's own local customer choice education program. Such program costs may include outreach programs, paid media, direct mail, company call center, grass roots outreach and other costs as approved by the Commission.

CEC(n) - consumer education costs for Low Volume Customers in rate class "n" including over/(under) recovery and associated interest.

E – The estimated over or (under) recovery from the prior year. The reconciliation period shall be the 12 months ended December 31.

I - Interest on any over or (under) recovery balance. Interest shall be a rate of 6% and shall be calculated from the month of over or under collection to the mid-point of the recovery period.

n – rate class where 1 = residential (Rate GR) 2 = small C&I (Rate GC) 3 = large C&I (Rate L).

S – projected MCF of gas, as included in the Balancing Service Costs (BSC) provided in the Company's most recent Commission approved annual 1307(f) Purchase Gas Cost (PGC) filing.

Filing Schedule:
The estimated surcharge shall be filed with the Commission by January 1 of each year to be effective on the following March 1. The application period shall be the 12 months that start the March 1 effective date of the surcharge. The CEC mechanism is subject to annual audit review by the Bureau of Audits.

(I) Denotes Increase

**DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC)**

In addition to the net charges provided for in this Tariff, a charge of 0.00% will apply consistent with the Commission Order dated September 3, 2015 at Docket No. P-2013-2347340, approving the DSIC. **(C)**

(C) Denotes Change

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

1. General Description

A. Purpose: To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not included for recovery in the DSIC.

B. Eligible Property: The DSIC-eligible property will consist of the following:

Piping (account 376);
Couplings (account 376);
Gas services lines (account 380) and insulated and non-insulated fittings (account 378);
Valves (account 376);
Excess flow valves (account 376);
Risers (account 376);
Meter bars (account 382);
Meters (account 381);
Unreimbursed costs related to highway relocation projects where a natural gas distribution company or city natural gas distribution operation must relocate its facilities; and
Other related capitalized costs.

C. Effective Date: The DSIC will become effective October 1, 2015.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

2. Computation of the DSIC

A. Calculation: The initial DSIC, effective October 1, 2015, shall be calculated to recover the fixed costs of eligible plant additions that have not previously been reflected in the Company's rates or rate base and will have been placed in service between June 1, 2015 and August 31, 2015. Thereafter, the DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update. Billing for the DSIC will be on a bills rendered basis. Thus, changes in the DSIC rate will occur as follows:

Effective Date of Change	Date to which DSIC Eligible Plant Additions Reflected
January 1	September - November
April 1	December - February
July 1	March - May
October 1	June - August

B. Determination of Fixed Costs: The fixed costs of eligible distribution system improvements projects will consist of depreciation and pre-tax return, calculated as follows:

1. Depreciation: The depreciation expense shall be calculated by applying the annual accrual rates employed in the Company's most recent base rate case for the plant accounts in which each retirement unit of DSIC-eligible property is recorded to the original cost of DSIC-eligible property.

2. Pre-tax return: The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Company's actual capital structure and actual cost rates for long-term debt and preferred stock as of the last day for the three-month period ending one month prior to the effective date of the DSIC and subsequent updates. The cost of equity will be the equity return rate approved in the Company's last fully litigated base rate proceeding for which a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years shall have elapsed between the entry of such a final order and the effective date of the DSIC, then the equity return rate used in the calculation will be the equity return rate calculated by the Commission in the most recent Quarterly Report on the Earnings of Jurisdictional Utilities released by the Commission.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

C. Application of DSIC: The DSIC will be expressed as a percentage carried to two decimal places and will be applied to the total amount billed to each customer for distribution service and the State Tax Adjustment Surcharge (STAS). To calculate the DSIC, one-fourth of the annual fixed costs associated with all property eligible for cost recovery under the DSIC will be divided by the Company's projected revenue for distribution service (including all applicable clauses and riders) for the quarterly period during which the charge will be collected, exclusive of the STAS.

D. Formula: The formula for calculation of the DSIC is as follows:

$$DSIC = \frac{(DSI * PTRR) + STFT + Dep + e) \times 1/(1-T)}{PQR}$$

Where:

DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation and associated accumulated deferred income taxes pertaining to property-related book/tax depreciation timing differences resulting from the use of accelerated depreciation per Internal Revenue Code, 26 U.S. Code § 168.
.

PTRR = Pre-tax return rate applicable to DSIC eligible property.

STFT = (State Tax Flow Through) Pre-tax flow through calculated on book-tax timing differences between accelerated tax depreciation and book depreciation net of federal tax
[Note that a utility may elect to include STFT calculation in the PTRR component).

Dep = Depreciation expense related to DSIC-eligible property.

e = Amount calculated (+/-) under the annual reconciliation feature or Commission audit, as described below.

T= If applicable, Pennsylvania Gross Receipts Tax rate in effect during the billing month, expressed in decimal form.

PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from applicable customers.

Revenue shall be based on one-fourth of the projected annual revenues.

[NOTE: THE DSIC CALCULATION DOES NOT FACTOR IN THE PLANT OF ACQUIRED TROUBLED COMPANIES OR THE REVENUE OF CUSTOMERS ACQUIRED FROM TROUBLED COMPANIES UNTIL SUCH PLANT AND CUSTOMER RATES HAVE BEEN PART OF A BASE RATE CASE BY THE ACQUIRING UTILITY.]

**DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)**

3. Quarterly Updates. Supporting data for each quarterly update will be filed with the Commission and served upon the Commission's Bureau of Investigation and Enforcement, the Commission's Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update.

4. Customer Safeguards

A. Cap: The DSIC is capped at 5.0% of the amount billed to customers for distribution service (including all applicable clauses and riders) as determined on an annualized basis.

B. Audit/Reconciliation: The DSIC is subject to audit at intervals determined by the Commission. Any cost determined by the Commission not to comply with any provision of 66 Pa C.S. §§ 1350, *et seq*., shall be credited to customer accounts. The DSIC is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year, or the Company may elect to subject the DSIC to quarterly reconciliation but only upon request and approval by the Commission. The revenue received under the DSIC for the reconciliation period will be compared to the Company's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year or in the next quarter if permitted by the Commission. If DSIC revenues exceed DSIC-eligible costs, such over-collections will be refunded with interest. Interest on over-collections and credits will be calculated at the residential mortgage lending specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, *et seq*.) and will be refunded in the same manner as an over-collection. The Company is not permitted to accrue interest on under collections

C. New Base Rates: The DSIC will be reset at zero upon application of new base rates to customer billings that provide for prospective recovery of the annual costs that had previously been recovered under the DSIC. Thereafter, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company's rates or rate base will be reflected in the quarterly updates of the DSIC.

D. Customer Notice: Customers shall be notified of changes in the DSIC by including appropriate information on the first bill they receive following any change. An explanatory bill insert shall also be included with the first billing.

E. All customer classes: The DSIC shall be applied equally to all customer classes, except that the Company may reduce or eliminate the Rider DSIC to any customer with competitive alternatives who are paying flexed or discounted rates and customers having negotiated contracts with the Company, if it is reasonably necessary to do so.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) (CONTINUED)

F. Earning Reports: The DSIC will also be reset at zero if, in any quarter, data filed with the Commission in the Company's then most recent Annual or Quarterly Earnings reports show that the Company would earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC as described in the pre-tax return section. The Company shall file a tariff supplement implementing the reset to zero due to overearning on one-day's notice and such supplement shall be filed simultaneously with the filing of the most recent Annual or Quarterly Earnings reports indicating that the Company has earned a rate of return that would exceed the allowable rate of return used to calculate its fixed costs

G. Residual E-Factor Recovery Upon Reset To Zero: The Company shall file with the Commission interim rate revisions to resolve the residual over/under collection or E-factor amount after the DSIC rate has been reset to zero.
The Company can collect or credit the residual over/under collection balance when the DSIC rate is reset to zero. The Company shall refund any overcollection to customers and is entitled to recover any undercollections as set forth in Section 4.B. Once the Company determines the specific amount of the residual over or under collection amount after the DSIC rate is reset to zero,the Company shall file a tariff supplement with supporting data to address that residual amount. The tariff supplement shall be served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the supplement.

RATE GR - GENERAL SERVICE -RESIDENTIAL

AVAILABILITY.

Service in the entire service territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units whether occupied or not), for domestic requirements of its members when such service is supplied through one meter. Resale of gas and/or service provided by the Company under this rate is only allowed for those locations being served through a single meter prior to January 6, 1980.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $15.70 per month
VARIABLE DISTRIBUTION CHARGE: $ 6.8122 per Mcf **(I)**

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE (“CC”) (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE (“GCA”), GAS PROCUREMENT CHARGE (“GPC”), MERCHANT FUNCTION CHARGE (“MFC”), and BALANCING SERVICE COST (“BSC”) apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge. The Universal Service Fund Charge is incorporated in the Variable Distribution Charge.

CONTROLLED LOW PRESSURE SERVICE AND 2 PSIG DELIVERY.

For those Customers served from medium or high pressure mains, low pressure delivery of gas at 12.2 inches of water column or 2 PSIG will be provided upon request in lieu of the normal low pressure delivery. For these Customers multipliers of 1.03 will be applied to all meter readings for 12.2 inches of water column delivery and 1.14 for 2 psig delivery to recognize the additional volume of gas delivered.

BUDGET BILLING.

At the option of the Customer, budget billing is available in accordance with the provisions of Rule 16.5.

RULES AND REGULATIONS.

The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.

The initial term for any contract shall be at least one year.

PAYMENT TERMS.

Standard.

(I) Denotes Increase

RATE GC - GENERAL SERVICE - COMMERCIAL AND INDUSTRIAL
(Effective through December 31, 2025)

AVAILABILITY.
Service for use in commercial and/or industrial applications, with the right reserved to restrict its use as boiler fuel and for other non-critical use.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $36.38 per month

VARIABLE DISTRIBUTION CHARGE: $5.1985 per Mcf for all or any part of the first 200 Mcf
$4.7485 per Mcf for the additional use

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE (“CC”) (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE (“GCA”), GAS PROCUREMENT CHARGE (“GPC”), MERCHANT FUNCTION CHARGE (“MFC”), and BALANCING SERVICE COST (“BSC”) apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

CONTROLLED LOW PRESSURE SERVICE AND 2 PSIG DELIVERY.

For those Customers served from medium or high pressure mains, low pressure delivery of gas at 12.2 inches of water column or 2 PSIG will be provided upon request in lieu of the normal low pressure delivery. For these Customers multipliers of 1.03 will be applied to all meter readings for 12.2 inches of water column delivery and 1.14 for 2 psig delivery to recognize the additional volume of gas delivered.

BUDGET BILLING.
At the option of a Customer, budget billing is available in accordance with the provisions of Rule 16.5

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
Standard.

RATE GC - GENERAL SERVICE - COMMERCIAL AND INDUSTRIAL

(Effective as of January 1, 2026)

AVAILABILITY.

Service for use in commercial and/or industrial applications, with the right reserved to restrict its use as boiler fuel and for other non-critical use.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE:

$29.36 for service provided through a single small diaphragm meter
$40.61 for all other service

VARIABLE DISTRIBUTION CHARGE: $5.1985 per Mcf for all or any part of the first 200 Mcf
$4.7485 per Mcf for the additional use

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE (“CC”) (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE (“GCA”), GAS PROCUREMENT CHARGE (“GPC”), MERCHANT FUNCTION CHARGE (“MFC”), and BALANCING SERVICE COST (“BSC”) apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

CONTROLLED LOW PRESSURE SERVICE AND 2 PSIG DELIVERY.

For those Customers served from medium or high pressure mains, low pressure delivery of gas at 12.2 inches of water column or 2 PSIG will be provided upon request in lieu of the normal low pressure delivery. For these Customers multipliers of 1.03 will be applied to all meter readings for 12.2 inches of water column delivery and 1.14 for 2 psig delivery to recognize the additional volume of gas delivered.

BUDGET BILLING.

At the option of a Customer, budget billing is available in accordance with the provisions of Rule 16.5

RULES AND REGULATIONS.

The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.

The initial contract term shall be at least one year.

PAYMENT TERMS.

Standard.

RATE OL - OUTDOOR LIGHTING SERVICE

AVAILABILITY.

Service for outdoor lighting by Company-approved lighting devices of the sizes hereinafter specified, where the consumption is not registered on a meter.

MONTHLY RATE TABLE.

Manufacturer's Rated Input to Lighting Devices	Nominal Mcf Rating Per Month	Distribution Charges When Not in Conjunction With Service Under Other Gas Rates	Distribution Charges When in Conjunction With Service Under Other Gas Rates
1,999 Btu/Hr.or less	1.5 Mcf	$9.5075	$4.7316
2,000 Btu/Hr.to 2,499 Btu/Hr.	1.7 Mcf	$11.0605	$6.3202
2,500 Btu/Hr.to 2,999 Btu/Hr.	2.1 Mcf	$12.4154	$7.6574
3,000 Btu/Hr.to 3,499 Btu/Hr.	2.4 Mcf	$13.8605	$9.1198

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE (“CC”) (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE (“GCA”), GAS PROCUREMENT CHARGE (“GPC”), and BALANCING SERVICE COST (“BSC”) apply to this rate.

INSTALLATIONS.

The Customer shall install, own and maintain the lighting devices and all tubing from the Company's service-supply pipe to the lighting devices.

FINAL CONNECTION.

The final connection of any lighting devices or tubing to the supply system shall be made by or under the supervision of a representative of the Company and the costs of such connections shall be borne by the Customer.

BUDGET BILLING.

At the option of the Customer, budget billing is available in accordance with the provisions of Rule 16.5

RULES AND REGULATIONS.

The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.

The initial contract term shall be at least one year.

PAYMENT TERMS.

Standard.

RATE L - LARGE HIGH LOAD FACTOR SERVICE

AVAILABILITY.

Large volume high load factor service for use in commercial and/or industrial applications, with the right reserved to restrict its use as a boiler fuel and for other non-critical use. This service shall be under a contract specifying in Mcf, the maximum daily quantity (MDQ) of natural gas to be supplied on a seasonal basis. The winter period MDQ may not exceed the summer period MDQ. Deliveries shall be as nearly as practicable at uniform hourly rates of flow.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE:	$297.01 per month
VARIABLE DISTRIBUTION CHARGE:	$8.0858 per Mcf for the first 50% of all usage.
	$2.4560 per Mcf for the additional use.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE (“CC”) (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE (“GCA”), GAS PROCUREMENT CHARGE (“GPC”), and BALANCING SERVICE COST (“BSC”), apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

MINIMUM CHARGE.

The monthly minimum charge shall be the Fixed Distribution Charge.

MEASUREMENT.

The quantities of gas used shall be determined from the Company's meters, corrected to standard conditions, namely 60° Fahrenheit temperature and 30 inches of mercury barometric pressure.

UNAUTHORIZED OVERRUN.

Any quantity of gas taken for this service on any day of the month in excess of the MDQ specified in the contract for this service shall constitute unauthorized overrun volume for such day, except when such excess results from fluctuations in day-to-day deliveries hereunder determined by the Company to be normal and in accordance with good operating practices. The sum of all such unauthorized volume in a month shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily Weighted prices for a particular calendar month are summed and the result is equal to the MWP.

RULES AND REGULATIONS.

The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

MDQ DETERMINATION.

Each Customer shall review the contract annually and shall supply the Company written notification by August 1 of the Customer's requested MDQ(s) for the coming contract year. The MDQ requested shall be subject to reduction by the Company for either or both of the seasonal periods in light of available gas supplies, winter deliverability constraints, or for other good reason before the contract becomes effective. Any reduction made by the Company below the prior year's MDQ(s) shall be limited to the Customer's boiler fuel and other non-critical use.

The Company may, with the consent of the Customer, increase the existing winter MDQ up to the level of the contracted summer MDQ at such time during the winter period when, in the judgment of the Company, sufficient quantities of gas are available for the balance of the contract year.

TERM OF CONTRACT.

The initial contract term shall be at least one year.

PAYMENT TERMS.

Standard.

RATE MV-F MOTOR VEHICLE SERVICE-FIRM

AVAILABILITY.
Firm motor vehicle service is available to Customers using natural gas exclusively as fuel for motor vehicles.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $67.80 per month.

ADDITIONAL FIXED DISTRIBUTION CHARGE: If the Customer contracts with the Company for the installation and maintenance of compressor equipment to deliver gas at the necessary pressure for vehicle use, there will be an additional Customer Charge as specified in the Customer's contract.

VARIABLE DISTRIBUTION CHARGE: $1.3192 per Mcf

ADDITIONAL VARIABLE DISTRIBUTION CHARGE: If the Customer contracts with the Company for the purchase of compressed gas at a Company-owned refueling location, there will be a compression and refueling charge of $2.66 per Mcf added for each Mcf of gas supplied.

MINIMUM CHARGE: The minimum charge per month shall be the Fixed Distribution Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE (“CC”) (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE (“GCA”), GAS PROCUREMENT CHARGE (“GPC”), BALANCING SERVICE COST (“BSC”), and any applicable fuel taxes apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
Standard.

RATE MV-I - MOTOR VEHICLE SERVICE-INTERRUPTIBLE

AVAILABILITY.

Interruptible motor vehicle service is available to Customers using natural gas for the sole purpose of a fuel for motor vehicles which have installed dual-fuel capability.

QUALITY OF SERVICE.

Upon notification by the Company, the Customer is required to transfer load to an alternate fuel. Under normal operating conditions, a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day. The Customer shall be responsible for maintaining alternate fuel equipment in good operating condition and arranging for adequate supplies of alternate fuel. Sales under this rate schedule are subordinate to all firm sales or firm transportation service provided by the Company.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION CHARGE: $58.50 per month

ADDITIONAL FIXED DISTRIBUTION CHARGE: If the Customer contracts with the Company for the installation and maintenance of compressor equipment to deliver gas at the necessary pressure for vehicle use, there will be an additional Customer Charge as specified in the Customer's contract.

VARIABLE DISTRIBUTION CHARGE AND COMMODITY CHARGES:

Prices shall be established by the Company based on the alternate fuels that this Customer class has the economic capability of consuming.

The total of the Variable Distribution Charge and the Commodity Charge shall be no less than the allocated monthly cost of gas plus three cents, plus the applicable gross receipts tax factor.

The total of the Variable Distribution Charge and the Commodity Charge shall not exceed the sum of the end block of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost ("BSC") and the Gas Cost Adjustment Charge ("GCA") of Rate GC.

The Company will provide the Pennsylvania Public Utility Commission with written notification of the Rate MV-I prices on an unbundled basis at least eight (8) business days before the beginning of the month in which any price revision is to occur. Once established, the price will remain in effect from month to month unless changed by the above notification procedure.

ADDITIONAL COMMODITY CHARGE: If the Customer contracts with the Company for the purchase of compressed gas at a Company-owned refueling location, there will be a compression and refueling charge of $2.65 per Mcf added for each Mcf of gas supplied.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) and any applicable fuel taxes apply to this rate.

OTHER CONDITIONS.

1. The Company reserves the right to enter the Customer's premises to inspect the equipment and apparatus at any time to determine whether the Customer's equipment and the Company's equipment is properly functioning, and whether the Customer is in compliance with all the provisions of this rate. It is the Customer's responsibility to inform the Company immediately if the Customer-owned or Company-owned control equipment does not operate properly.

2. Service under this rate may be separately supplied to a Customer who is also supplied under one or more other gas rates at the same premises, provided that each supply shall be separate and distinct with respect to delivery, metering and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

RATE MV-I - MOTOR VEHICLE SERVICE-INTERRUPTIBLE - Continued

3. Upon notification by the Customer to the Company that an emergency condition exists, the Company may, in its sole discretion, authorize the Customer to continue the use of gas during a period of interruption until such emergency condition has been corrected. The price of each Mcf of gas consumed during such emergency authorization will be increased by the difference between the allocated monthly cost of gas and the greater of:

a. The highest incremental supply cost incurred by the Company during the period such emergency service is provided;

b. The equivalent unleaded gasoline dealer tank wagon price as posted in the Journal of Commerce and as determined from the average of the three highest prices at Philadelphia for the month.

The Company may require affidavits or other documentation in order to verify the cause and duration of the emergency condition sustained by the Customer. The revenue received for Customer emergency service which is in excess of the normal Rate MV-I revenue will be returned to Customers by including the revenues in the GCA of the Sales Service Costs provision.

4. Any unauthorized gas consumed in violation of the provisions of this rate shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate. Such payment by the Customer for unauthorized use shall not be deemed as giving the Customer any rights to use such gas.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission). All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

5. Should the Customer cause the control device to be ineffective, or in any way change the operation thereof, all gas registered on the meter since the last meter reading, in addition to all other rates and charges, will be subject to the penalty charge shown above.

6. The Company may, after furnishing reasonable notice, permanently discontinue service to such Customer upon a finding by the Company that the Customer has not complied with the conditions and provisions of this rate.

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
Standard.

RATE IS - INTERRUPTIBLE SERVICE

AVAILABILITY.

Interruptible sales service is available to individual Customers who have dual-fuel capability or are willing to accept interruption of gas service. The Customer must have an estimated gas consumption of at least 3,000 Mcf per month during each summer month. The summer period includes the months of April through October. For a Customer that also receives service under Rates L, TS-I, or TS-F, the 3,000 Mcf per month use requirement does not apply.

Rate GC or other firm sales services may not be used as a backup supply during periods of interruption under this rate schedule. Rate GC service may be provided through separate metering where firm service is required. Piping connections between the firm and interruptible fuel line systems are prohibited.

The Customer will be required to execute a contract specifying the maximum daily quantity (MDQ) of gas that the Company's service and metering facilities are designed to supply. The maximum hourly capacity that the Company's facilities are designed to supply shall not be more than 6.5% of the MDQ.

QUALITY OF SERVICE.

Service under this rate is made available to Customers for purposes of balancing the Company's gas demands and optimizing its daily use of pipeline supplies and is strictly within the discretion of the Company. When the available quantity of gas is inadequate to serve the needs of all Customers under this rate, the Company will impose limitations, as necessary, endeavoring to provide each Customer with the opportunity to take gas from time to time. Under normal operating conditions, a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day. Those Customers who have dual fuel capability shall be responsible for maintaining alternate fuel equipment in good operating condition and arranging for adequate supplies of alternate fuel. Interruptible sales are subordinate to all firm sales or firm transportation service provided by the Company.

BILLING.

FIXED DISTRIBUTION CHARGE: $297.41 per month.

VARIABLE DISTRIBUTION AND COMMODITY CHARGES:

Prices shall be established by the Company based on the alternate fuels the Customer has the economic capability of consuming. The total of the Variable Distribution Charge and the Commodity Charge shall be no less than the applicable commodity cost of gas for the current month plus three cents, increased by the applicable gross receipts tax factor and shall be no higher than the applicable delivered price, on an equivalent BTU basis of alternate fuel.

The Company will provide the Pennsylvania Public Utility Commission with written notification of each of the prices on an unbundled basis at least eight (8) business days before the beginning of the month in which any price revision is to occur. Once established, prices will remain in effect from month to month unless changed in accordance with the above notification procedure. If there is a major change in competitive fuel prices during the month, the Company may change the Commodity Charge prices within the same upper and lower limits on notice of five working days to the Commission.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Charge.

METERING SEQUENCE.

Service under this rate may be supplied in combination with Rates L, TS-F or TS-I at a single point and through a single metering installation, in which case the MDQ for each rate schedule shall be specified in the contract. The Company will assume for billing purposes that metered volumes first reflect deliveries of the Contract Maximum Daily Quantity of Rate L gas, next the Firm Transportation Contract Quantity of Rate TS-F, next the Contract Quantity of Interruptible Transportation under Rate TS-I, and finally the Interruptible Gas under this rate schedule. Determination of Rate IS deliveries will be made at the end of the billing period. The number of Mcf billed under Rate L shall never be less than the number of Mcf resulting from 15 days' use of the Rate L billing demand.

STATE TAX ADJUSTMENT CLAUSE and DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) apply to this rate.

RATE IS - INTERRUPTIBLE SERVICE - Continued

OTHER CONDITIONS.

1. Any quantity of gas taken for this service on any day of the month in excess of the MDQ specified in the contract shall constitute unauthorized overrun volume for such day, except when such excess results from fluctuations in day-to-day deliveries hereunder determined by the Company to be normal and in accordance with good operating practices. The sum of all such unauthorized volume in a month shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission). All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

2. Upon notification by the Customer to the Company that an emergency condition exists, the Company may, in its sole discretion, authorize the Customer to continue the use of gas during a period of interruption until such emergency condition has been corrected. The price of each Mcf of gas consumed during such emergency authorization will be increased by the difference between the applicable commodity cost used to establish the current Rate IS Commodity Charge for the Customer and the greater of:

a. The highest incremental supply cost incurred by the Company during the period such emergency service is provided;

b. The equivalent No. 2 oil consumer tank car price as posted in the Journal of Commerce and as determined from the average of the three highest prices at Philadelphia for the month.

The Company may require affidavits or other documentation in order to verify the cause and duration of the emergency condition sustained by the Customer. The Company may, after furnishing reasonable notice, permanently discontinue service to such Customer upon a finding by the Company that the Customer has not complied with the conditions and provisions of this rate schedule.

The revenue received for Customer emergency service which is in excess of the normal Rate IS revenue will be returned to Customers by including the revenues in the GCA of the Sales Service Costs provision.

EXTENSION OF MAIN - INSTALLATION OF SERVICE.

Each Customer shall prepay the total cost of any main extension, service installation, meter installation, or enlargement or rearrangement of existing facilities required for service under this rate schedule.

RULES AND REGULATIONS.

The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.

The initial contract term shall be at least 1 year.

PAYMENT TERMS.

Standard.

RATE TCS - TEMPERATURE CONTROLLED SERVICE

AVAILABILITY

Temperature controlled service is available to individual Customers that have dual-fuel equipment with a rated input of more than 2,100,000 Btu per hour and an estimated fuel use which totals 5,000 Mcf or more during the billing months of December, January, February and March and are willing to accept interruption of service at the cut-off temperature specified by the Company.

QUALITY OF SERVICE.

Upon notification by the Company, the Customer is required to transfer load to an alternate fuel whenever the outdoor temperature is below the cut-off limit specified by the Company. Under normal operating conditions, a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day. During August of each year the Company will notify each Customer of the cut-off temperature limit to be effective during the twelve-month period beginning September 1. Those Customers who have dual fuel capability shall be responsible for maintaining alternate fuel equipment in good operating condition and arranging for adequate supplies of alternate fuel. Sales under this rate are subordinate to all firm sales or firm transportation service provided by the Company.

BILLING.

FIXED DISTRIBUTION CHARGE: $170.00 per month.

VARIABLE DISTRIBUTION AND COMMODITY CHARGES:

Prices shall be established by the Company based on the alternate fuels that this Customer class has the economic capability of consuming.

Monthly prices shall not exceed the sum of the end block of the Variable Distribution Charge of Rate GC, the monthly projected weighted average commodity cost of gas (WACCOG) and the Fixed Cost Credit determined in the most recent annual 1307(f) proceeding. Monthly prices shall be no less than monthly projected WACCOG and the 1307(f) Fixed Cost Credit, plus three cents. The Company will provide the Pennsylvania Public Utility Commission with written notification of the prices on an unbundled basis at least eight (8) business days before the beginning of the month in which any price revision is to occur. If there is a significant change in WACCOG during a month, the Company may change the commodity charge prices within the same upper and lower limits on notice of five working days to the Commission.

"Fixed Cost Credit" means the result derived by dividing the Company's annual projected interstate pipeline transportation and storage demand charges by its projected annual firm sales throughput as determined by reference to the Company's Section 1307(f) filing made immediately prior to the period in which the Fixed Cost Credit shall apply.

"Commodity cost of gas" shall include all purchased gas costs charged by the Company's natural gas and interstate pipeline suppliers on a volumetric or commodity basis (including but not limited to interstate pipeline fuel and the Company's company use and unaccounted for gas) and shall exclude all costs used in determining the Fixed Cost Credit.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Charge.

STATE TAX ADJUSTMENT CLAUSE and DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) apply to this rate.

OTHER CONDITIONS.

1. The Company reserves the right to enter the Customer's premises to inspect the equipment and apparatus at any time to determine whether the Customer's equipment and the Company's equipment is properly functioning, and whether the Customer is in compliance with all the provisions of this rate.
It is the Customer's responsibility to inform the Company immediately if the Customer-owned or Company-owned control equipment does not operate properly.

2. Service under this rate may be separately supplied to a Customer who is also supplied under one or more other gas rates at the same premises, provided that each supply shall be separate and distinct with respect to delivery, metering and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

The Company may, in its sole discretion, permit minimal volumes of gas which would otherwise be supplied under Rate GC to flow through the Rate TCS metering where, in the Company's judgment, the cost of installing separate metering is uneconomical.

(Continued)

RATE TCS - TEMPERATURE CONTROLLED SERVICE – Continued

3. Upon notification by the Customer to the Company that an emergency condition exists, the Company may, in its sole discretion, authorize the Customer to continue the use of gas during a period of interruption until such emergency condition has been corrected. The price of each Mcf of gas consumed during such emergency authorization will be increased by the difference between the allocated monthly cost of gas and the greater of:

a. The highest incremental supply cost incurred by the Company during the period such emergency service is provided;

b. The equivalent No. 2 oil consumer tank car price as posted in the Journal of Commerce and as determined from the average of the three highest prices at Philadelphia for the month.

The Company may require affidavits or other documentation in order to verify the cause and duration of the emergency condition sustained by the Customer. The revenue received for Customer emergency service which is in excess of the normal Rate TCS revenue will be returned to Customers by including the revenues in the GCA of the Sales Service Costs provision.

4. Upon notification to the Customer by the Company that an emergency condition exists, the Company may change the threshold outdoor ambient temperature at which service is provided, for the duration of the emergency.

5. Any unauthorized gas consumed in violation of the provisions of this rate shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate. Such payment by the Customer for unauthorized use shall not be deemed as giving the Customer any rights to use such gas.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price.(In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

6. Should the Customer cause the control device to be ineffective, or in any way change the operation thereof, all gas registered on the meter since the last meter reading, in addition to all other rates and charges, will be subject to the penalty charge shown above.

7. The Company may, after furnishing reasonable notice, permanently discontinue service to such Customer upon a finding by the Company that the Customer has not complied with the conditions and provisions of this rate.

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least 1 year.

PAYMENT TERMS.
Standard.

GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS

(Applicable to: Rate TS-I Gas Transportation Service-Interruptible and Rate TS-F Gas Transportation Service-Firm.)

1. TRANSPORTATION SERVICE

1.1 GENERAL. Transportation service shall consist of: the receipt of gas on behalf of a Customer; the transportation of gas through the Company's distribution facilities, and the delivery of equivalent quantities of gas to the Customer, adjusted for thermal correction and system losses where applicable.

Transportation service may also include Standby Sales Service to permit purchases of gas under one of the Company's retail sales rate schedules.

1.2 TERMS DEFINED. The following definitions shall apply throughout the transportation portion of this tariff:

RECEIVED/RECEIPT shall refer to gas tendered to the Company for the Customer's account at one or more of the interconnections between the Company and its interstate pipeline suppliers, or other specified location. The normal unit of measurement is the dekatherm or mmBtu.

DELIVERED/DELIVERY shall refer to gas tendered to the Customer by the Company at the Customer's specified location. The normal unit of measurement is the Mcf.

USE/USAGE shall refer to gas actually consumed by the Customer at the specified location as measured by the Company's meter in Mcf.

DEFICIENT DELIVERIES shall refer to occurrences in which the Customer uses more gas than the quantity of transportation gas tendered by the Company for delivery.

EXCESS DELIVERIES shall refer to occurrences in which the Customer uses less than the quantity of gas tendered by the Company for delivery.

1.3 VOLUME ADJUSTMENT. The quantity of transportation gas received into the Company's distribution system for the Customer's account shall be: (a) reduced by 3.3% for system losses; and (b) adjusted for thermal correction determined by **(C)** dividing the daily average Btu content per cubic foot of gas for the Company's system by a reference Btu content of 1,000 Btu per cubic foot. Where the transported gas can be delivered directly to the Customer without commingling with other system supplies, no reduction for system losses shall be made, and the thermal correction shall be based on the daily average Btu content of the pipeline to which the Customer is directly connected.

1.4 SUPPLY COST ADJUSTMENT. If the Company incurs any added gas supply cost in order to provide transportation service by displacement, or for other reasons, such additional cost will be charged to the Customer. Displacement occurs when a Customer, who is directly connected to one of the Company's pipeline suppliers, arranges for receipt of transportation gas on another pipeline to which the Customer is not directly connected. Revenues received by the Company in payment for added gas supply cost will be credited to firm sales Customers through the annual Sales Service Costs reconciliation (Section 1307[f]).

1.5 SERVICE AGREEMENT. The Customer will be required to execute a Transportation Service Agreement which will specify an initial Transportation Contract Quantity (TCQ) to be the maximum daily volume of gas, expressed in Mcf net of system losses where applicable, to be transported and delivered to the Customer. The agreement will also specify delivery locations, the election of Standby Sales Service, the commodity charge to be in effect for the term of the agreement, and any special provisions for service. The standard term for a Transportation Service Agreement shall be twelve months, unless the Company and the Customer agree to a shorter or longer term.

The TCQ shall not exceed the lower of (a) the capacity of the Company's metering and regulating equipment at the Customer's location; or (b) 110% of the maximum daily usage of the Customer during the twelve-month period prior to the execution of the Transportation Service Agreement, unless full documentation of new or additional gas usage capability is provided by the Customer. If a Customer chooses to designate an Agent to act on the Customer's behalf for scheduling, dispatching, billing and other administrative aspects of transportation service, such designation shall be made in the Transportation Service Agreement. The designation of an Agent shall not relieve the Customer of ultimate responsibility for payment for service or other obligations incurred under this tariff.

Every November 1 following execution of the Transportation Service Agreement, the Customer’s TCQ shall be automatically adjusted by the Company to be 110% of the maximum daily usage of the Customer during the prior twelve-month period if such adjustment would raise or lower the customer TCQ by the higher of either 10 mcf or 10%. The TCQ may also be adjusted by mutual agreement of the Customer and the Company.

(Continued)

(C) Denotes Change

GAS TRANSPORTATION SERVICE GENERAL TERMS AND CONDITIONS – Continued
(Applicable to: Rate TS-I Gas Transportation Service Interruptible and Rate TS F Gas Transportation Service Firm.)

1.6 BUYER GROUP/LEAD CUSTOMER. A Buyer Group generally consists of up to ten individual Customers who voluntarily join together to obtain either firm or interruptible transportation service. The Company, at its discretion, may require all members of the Buyer Group to execute the same Transportation Service Agreement and make the same elections as to Standby Sales Service. One member of the Buyer Group may be designated by the Company as the Lead Customer who shall be responsible for the timely payment of all bills rendered to the Buyer Group, as well as all day to day dispatch scheduling coordination and administrative communication between the Company and all members of the Buyer Group. A member of one Buyer Group may not be a member of another Buyer Group. Eleven or more individual Customers may form a Buyer Group only upon specific agreement by the Company. Unless otherwise described, the term "Customer" as used throughout these general terms and conditions shall refer to an individual Customer or to a Buyer Group. The Company, at its discretion, may set the maximum Commodity Charge for a Buyer Group at the maximum which any member would be individually required to pay.
1.7 MINIMUM SIZE. The minimum total gas consumption capability required to be eligible for transportation service shall be less than or equal to 5,000 Mcf per year. This minimum shall apply to an individual Customer or to a Buyer Group which, in the aggregate, uses less than or equal to 5,000 Mcf of gas annually.

2. BALANCING PROVISIONS

2.1 GENERAL. Transportation balancing is provided to adjust for the unavoidable minor variations between Customer usage and scheduled deliveries, and is not intended to function as a storage service or a standby sales service. Each Customer shall use best efforts to balance deliveries and usage at all times.
2.2 INTERRUPTED RECEIPTS. On days when no transportation gas is received for the Customer's account, all gas used by the Customer shall be billed as a purchase from the Company. For Customers which have elected Standby Sales Service, the usage shall be billed at the applicable rate. For Customers which have not elected Standby Sales Service, the usage shall be billed at the sum of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost (“BSC”) and, the Gas Cost Adjustment Charge (“GCA”) of Rate GC and a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. Excess deliveries already being held for the Customer at the time of interruption will be tendered for delivery when transportation receipts resume. If the interruption of receipts continues for more than thirty days, the Company will tender excess deliveries as soon as practicable subject to operating and gas procurement considerations.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6, non-NY

North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

2.3 BALANCING CHARGE. A **$0.0229** per Mcf balancing charge shall be imposed on all transportation deliveries in a billing month. The Balancing Charge shall be reviewed and adjusted annually, as necessary, effective December 1 subject to approval of the new charge in the Company’s annual purchased gas cost filing under 66 Pa. C.S. § 1307(f) **(I)**
2.4 ALLOWABLE DAILY VARIATION. In order to minimize the effect of transportation imbalances on the operation of the system, the allowable daily variation between delivered quantities and Customer usage is ten percent of the TCQ.
If a Customer exceeds these limits, the Company shall: (a) in the case of excess deliveries, impose a $0.25 per Mcf penalty charge on that portion of daily excess deliveries greater than the allowable daily variation and have the right to limit the receipt of Gas Transportation if a customer has excess deliveries greater than the allowable daily variation (b) in the case of deficient deliveries, have the right to bill such deficiency as a purchase from the Company. For Customers which have elected Standby Sales Service, the deficiency shall be billed at the applicable rate. For Customers which have not elected Standby Sales Service, the deficiency shall be billed at the sum of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost (“BSC”) and, the Gas Cost Adjustment Charge (“GCA”) of Rate GC, and a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6, Non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

(I) Denotes Increase

GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS - Continued

(Applicable to: Rate TS-I Gas Transportation Service-Interruptible and
Rate TS-F Gas Transportation Service-Firm.)

2.5 MONTHLY BALANCING FOR DEFICIENT DELIVERIES. If in any billing month a Customer has deficient deliveries, the volumes shall be billed at the applicable rate for those customers that have elected Standby Sales Service. For Customers which have not elected Standby Sales Service, the volumes shall be billed at the sum of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost (“BSC”) and Gas Cost Adjustment Charge (“GCA”) of Rate GC, and a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 Non-NY North Daily rate for such unauthorized usage day; or b) the Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

2.6 MONTHLY BANKING SERVICE FOR EXCESS DELIVERIES. The Customer is permitted to carry over or bank a positive imbalance each month at the following monthly charges:

(a) where the monthly excess does not exceed the TCQ - $0.00 per Mcf;
(b) for the monthly excess greater than the TCQ and less than twice the TCQ - $1.00 per Mcf;
(c) for the monthly excess greater than twice the TCQ and less than three times the TCQ - $5.00 per Mcf;
(d) for the monthly excess greater than three times the TCQ - $10.00 per Mcf.

3. STANDBY SALES SERVICE

3.1 GENERAL. Standby Sales Service permits the Customer to purchase gas under one of the Company's retail sales rate schedules when:
(a) no transportation gas is received for the Customer;
(b) transportation deliveries are deficient with respect to the Customer's usage;
(c) a Customer elects to purchase gas from the Company in lieu of transportation service.

Transportation service under Rate TS-I automatically provides Standby Sales Service as described in Section 3.2 below. A Customer purchasing transportation service under Rate TS-F shall indicate in the Transportation Service Agreement if the Customer elects to have Standby Sales Service. If the Customer elects Standby Sales Service, the Customer shall specify the election in the Transportation Service Agreement as well as the Standby Sales Quantity (SSQ) which is the maximum daily quantity of gas expressed in Mcf that the Customer may purchase. A penalty charge based on the following will be imposed on volumes taken in excess of the SSQ: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

The Company maintains no current or future duty to provide retail sales service to a Customer who declines to elect Standby Sales Service. Availability of Standby Sales Service for new gas loads not previously served under a retail firm sales rate schedule is contingent upon the Company's ability to arrange the required supply contracts.

3.2 INTERRUPTIBLE SERVICE. Interruptible Standby Sales Service under Rate IS is automatically provided to the Customer in conjunction with Rate TS-I. The billing and all other conditions of service shall be as stated under the Rate IS tariff, except that the Customer Charge shall be waived.

GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS - Continued

(Applicable to: Rate TS-I Gas Transportation Service-Interruptible and
Rate TS-F Gas Transportation Service-Firm.)

3.3 FIRM SERVICE. All Rate TS-F Customers may elect Standby Sales Service under:
(a) Rate L, for Customers with an SSQ of at least 100 Mcf per day and gas consumption capability of at least 18,000 Mcf per year;

(b) Rate GC, for Customers with an SSQ of less than 100 Mcf per day or gas consumption capability of less than 18,000 Mcf per year except that the Standby Sales Service rate schedule applicable to a Buyer Group may, at the Company's discretion, be set at the highest priced rate schedule under which any member would be individually required to pay. The billing and all other conditions of service shall be as stated in the applicable rate schedule and prorated for actual days of use, except that the Customer Charge shall be waived. In addition, the Customer shall pay a monthly demand charge per Mcf of SSQ which is based on 110% of the average monthly demand charges paid for the Company's firm supply. The monthly demand charge, prorated on an Mcf-per-day basis, will be credited to all volumes purchased. Following the end of the Company's supply contract year (October 31), the Customer shall also be assessed those minimum bill, take-or-pay, supply inventory, or other similar charges actually paid by the Company, which are attributable to the annual volume reserved but not taken under this provision. Customers that request to terminate Standby Sales Service after one or more years will be required to continue payment of the monthly demand charge until the Company is able to reduce its purchase obligations or otherwise utilize the released supplies.

4. OTHER PROVISIONS

4.1 METERING SEQUENCE. Where gas is used by the Customer under more than one of the Company's rate schedules through the same meter location, the Company will assume for billing purposes that metered volumes reflect deliveries in the following sequence where applicable:

(a) Rate L, up to maximum daily quantity.
(b) Rate TS-F, up to transportation contract quantity.
(c) Rate TS-I, up to transportation contract quantity, or actual delivered quantity, whichever is lower.
(d) Rate IS.

4.2 GAS SUPPLY SHORTAGE. The Company shall have the right to appropriate natural gas supplies to be delivered by or on behalf of a Customer in the event of a natural gas emergency (as defined in Rule 12 of the Rules and Regulations). In the event of a natural gas emergency, the Customer or its Natural Gas Supplier (NGS) shall continue to deliver all available natural gas supplies to the Company for which the Customer is contracted to purchase from the NGS. As compensation, the Company shall pay a price not in excess of the greater of the city gate cost of the appropriated natural gas, including transportation charges up to the Company's city gate, or the reasonable cost actually paid by the customer for delivered substitute energy, as documented by the Customer. The Company may also provide compensation in kind at the discretion of the affected customer or NGS. Upon request, the Customer shall demonstrate its cost of natural gas by making a copy and invoice of the contract with the natural gas supplier available to the Company upon request.

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4.3 LIABILITY.

(a) The Company shall not be liable for curtailment of service under this rate schedule or loss of gas of the Customer as a result of any steps taken to comply with any law, regulation, or order of any governmental agency with jurisdiction to regulate, allocate, or control gas supplies or the rendering of service hereunder, and regardless of any defect in such law, regulation, or order.

(b) Gas shall be and remain the property of the Customer while transported and delivered by the Company. The Customer shall be responsible for maintaining all insurance it deems necessary to protect its property interest in such gas before, during, and after receipt by the Company.

(c) The Company shall not be liable for any loss to the Customer arising from or out of service under this rate schedule, including loss of gas in the possession of the Company or any other cause. The Company reserves the right to commingle gas of the Customer with other supplies.

(d) The Company shall not be liable, under any circumstances or in any respect, to a Customer, to a gas producer or natural gas supplier, or to any other person or entity for damages arising either directly or indirectly from interruption, curtailment, or termination of transportation service.

TERM OF CONTRACT.

The initial contract term shall be at least one year.

RATE TS-I GAS TRANSPORTATION SERVICE-INTERRUPTIBLE

(Gas Transportation Service - General Terms and Conditions Apply To This Rate.)

AVAILABILITY.

Interruptible transportation service (Rate TS-I) is available to an individual Customer, or a Buyer Group, who may have dual fuel capability or is willing to accept interruption of gas service.

Service is available under this rate only to customers served by a licensed natural gas supplier who is deemed creditworthy by the Company pursuant to Rule 25 of the Rules and Regulations of the Gas Service Tariff.

High Volume Transportation (HVT) Customers receiving service under this Rate, as of March 1, 2002, shall be exempt from the above supplier eligibility criteria; provided, however, such an HVT Customer may waive such exemption, in a writing submitted to the Company, by indicating its desire to be served by a natural gas supplier deemed creditworthy by the Company pursuant to the above referenced Rule 25.

UPGRADING AND OR INSTALLATION OF FACILITIES.

Upgrading and/or installation of mains and services required to provide adequate delivery capacity for interruptible transportation service for the Customer will be in accordance with the Rules and Regulations governing Extensions. The Customer shall prepay the total cost of any new receipt point for Customer-owned gas into the Company system, or improvements to an existing receipt point, which then shall be constructed, subject to specific contract terms and conditions, owned, and maintained by the Company.

QUALITY OF SERVICE.

Interruptible transportation service will be provided on a best efforts basis by the Company and may be restricted or interrupted from time to time due to operating and capacity limitations. Under normal operating conditions a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day.

BILLING.

A. For each meter location having a gas consumption capability of at least 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE.
      $575.82 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $217.35.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The maximum Variable Distribution Charge shall be $0.9954 per Mcf.

B. For each meter location having a gas consumption capability of less than 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE.
      $435.59 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $217.35.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual customer. The maximum Variable Distribution Charge shall be $1.7293 per Mcf.

C. The State Tax Adjustment Clause does not apply to this rate.

D. DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) applies to this rate.

MINIMUM CHARGE.

The monthly minimum charge shall be the Customer Charge.

SEPARATION OF SERVICE.

Service under this rate may be separately supplied to a Customer who is also supplied under Rate GC at the same premises provided that each supply shall be separate and distinct with respect to delivery, metering, and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

PAYMENT TERMS.

Standard.

RATE TS-F GAS TRANSPORTATION SERVICE-FIRM

(Gas Transportation Service - General Terms and Conditions Apply To This Rate.)

AVAILABILITY.

Firm transportation service (Rate TS-F) is available to an individual Customer or a Buyer Group, who desires uninterrupted transportation service. Firm transportation service is not available with Rate GC through the same meter, except as provided under Standby Sales Service of the General Terms and Conditions.

Service is available under this rate only to customers served by a licensed natural gas supplier who is deemed creditworthy by the Company pursuant to Rule 25 of the Rules and Regulations of the Gas Service Tariff.

High Volume Transportation (HVT) Customers receiving service under this Rate as of March 1, 2002, shall be exempt from the above supplier eligibility criteria; provided, however, such an HVT Customer may waive such exemption, in a writing submitted to the Company, by indicating its desire to be served by a natural gas supplier deemed creditworthy by the Company pursuant to the above referenced Rule 25.

UPGRADING AND OR INSTALLATION OF FACILITIES.

Upgrading and/or installation of mains and services required to provide adequate delivery capacity for firm transportation service for the Customer will be in accordance with the Rules and Regulations governing Extensions. The Customer shall prepay the total cost of any new receipt point for Customer-owned gas into the Company system, or improvements to an existing receipt point, which then shall be constructed, subject to specific contract terms and conditions, owned, and maintained by the Company.

QUALITY OF SERVICE.

Transportation service under this rate schedule is firm and shall be interrupted only in cases of operating emergencies experienced by the Company or in the case of a natural gas shortage when the supply of gas is insufficient to meet the requirements of Priority 1 Customers.

BILLING.

A. For each meter location having a gas consumption capability of at least 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE
      $504.83 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $217.35.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The maximum Variable Distribution Charge shall be $ 1.3470 per Mcf.

B. For each meter location having a gas consumption capability of less than 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE.
      $378.23 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $217.35.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The maximum Variable Distribution Charge shall be $2.7319 per Mcf.

C. The State Tax Adjustment Clause does not apply to this rate.

D. DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) applies to this rate.

MINIMUM CHARGE.

The monthly minimum charge shall be the Customer Charge plus 15 days' use of the TCQ at the Customer's applicable commodity charge.

SEPARATION OF SERVICE.

Service under this rate may be separately supplied to a Customer who is also supplied under Rate GC at the same premises provided that each supply shall be separate and distinct with respect to delivery, metering, and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

PAYMENT TERMS.

Standard.

RATE NGS - Negotiated Gas Service

AVAILABILITY. Service under this rate is available only to customers that satisfy the following criteria:

1. The customer either must have a history of at least 18,000 Mcf of annual natural gas usage billed by the Company. Alternatively, if a new customer, the customer must establish that the facilities to be served are likely to consume at least 18,000 Mcf of annual natural gas usage.

2. The customer must document a viable, currently available competitive alternative to service under the Rates GC, L, TS-F, or TS-I including any applicable riders. Documentation must include a written description of the competitive alternative and any further information necessary to establish the cost and demonstrate the viability of the customer's competitive alternative with reasonable certainty. The Company shall have sole discretion over whether the customer is eligible for a rate negotiated pursuant to this rate based on the information provided by the customer. If the customer already has in place a competitive alternative, the Company may require such written proof of the existence, nature, and working condition of such alternative, as the Company deems appropriate and necessary.

3. The customer executes an NGS agreement that comports with all other provisions of this rate.

4. As per Commission Order at Docket No. R-2020-3018929 (Order Entered June 22, 2021), the Company is required to provide an updated competitive alternative analysis to the Commission for any customer that has not had their alternative fuel source verified for a period of five years or more at the point when the Company files a base rate case.

QUALITY OF SERVICE. Service quality shall be negotiated and specified in each service agreement. Service quality may be firm, interruptible or a hybrid thereof. Priority 1 customers, however, shall be required to take firm standby service as a component of service provided under this rate schedule unless the customer demonstrates to the Company's reasonable satisfaction that it has an installed, operable backup system. Unless expressly stated in the service agreement, an interruptible customer shall bear the entire risk for any and all damages associated with an interruption.

NATURE OF SERVICE. The nature of service shall be negotiated and specified in each service agreement. Service may involve any one or more of the following services: supply; transportation; storage; upgrade or installation of mains, services, and appurtenant facilities; and such other natural gas management services the customer may require from time to time. The service agreement shall include all essential terms and conditions of the negotiated service. Where a term is not defined expressly in the service agreement, it shall have the meaning specified in the Tariff or, if the Tariff does not provide a definition, the meaning generally understood within the natural gas industry.

TERM LENGTH/NOTICE OF TERMINATION. The primary term length of a service agreement shall be no less than one year in length. Either the customer or the Company may terminate the agreement at the end of the primary term by giving written notice of termination at least one hundred-eighty (180) days before primary term ending date unless otherwise stated in the service agreement. If neither party gives such notice, then the agreement shall continue for consecutive one year terms until terminated by either party giving written notice of termination at least one hundred-eighty (180) days before the end of the continued term. Terms and conditions applicable to any continued term shall be stated in the service agreement.

RATES, CHARGES, BILLING.

1. Rates for service shall be negotiated and specified in the applicable service agreement. Rates negotiated for this service shall be presumed to have been designed to recover a fair rate of return on the incremental investment in facilities needed to provide service to the customer.

2. Rates will be, in the Company's sole judgment, competitive but the Company shall not be obligated to agree to charges that match the customer's costs under the customer's viable, currently available competitive alternative.

3. Unless otherwise stated in the service agreement, no charge of otherwise general applicability (e.g., State Tax Adjustment Clause) shall apply to service under this rate.

4. Unless otherwise stated in the service agreement, no charge applicable to other sales or transportation services offered under the Company's tariff (e.g., Rates GC, L, TS-I, TS-F) shall apply to service under this rate.

PAYMENT TERMS. Payment terms may be negotiated and specified in the service agreement. Unless the service agreement provides specific terms governing the billing of charges, Section 16. Standard Payment Terms of the Rules and Regulations of the Tariff shall apply.

RULES AND REGULATIONS. The Company's Rules and Regulations in effect from time to time, where not inconsistent with any provision hereof or the terms and conditions of the applicable service agreement, shall apply to a service agreement negotiated under this rate.

RATE NGS - Negotiated Gas Service - Continued

CREDITWORTHINESS

1. Prior to commencement of performance, or at any time during the term of service under this rate, Customer must provide financial information reasonably requested by the Company to ascertain Customer's ability to discharge its payment or other obligations under this rate. The Company shall be permitted to conduct financial evaluations during the term of the service agreement when information received by the Company indicates that the effective Credit Assurance has become unsatisfactory. The Company may charge $100.00 for each evaluation up to two evaluations per calendar year.

2. Based on the Company's initial or subsequent credit evaluation, the Company may refuse, suspend or terminate service under this rate if the Customer fails to deliver the requested credit information or assurance of its ability to pay within ten (10) business days of such request. Credit Assurance may include (i) the required posting of an irrevocable letter of credit acceptable to the Company, (ii) a cash prepayment in an amount acceptable to the Company, (iii) a corporate guaranty or (iv) other security acceptable to the Company.

3. Upon five days prior written notice ("Notice Period") to an NGS customer, the Company may suspend or terminate service to the customer upon the occurrence of a Default Event. A Default Event shall mean (i) the failure by the customer to make, when due, any payment or perform any obligation required under the service agreement, (ii) any representation or warranty made by the customer shall prove to have been false or misleading in any material respect when made, (iii) the customer is subject to a Bankruptcy Proceeding, or (iv) the customer fails to post satisfactory Credit Assurance. If the customer cures the Default Event within the Notice Period, service will be continued by the Company pursuant to the terms of the service agreement.

CONFIDENTIALITY/PENALTY FOR DISCLOSURE.

1. The terms and conditions of a service agreement executed pursuant to this rate shall be considered "Highly Confidential and Privileged" by the parties and by the Commission.

2. "Highly Confidential and Privileged" shall mean that disclosure to any third party, non-governmental entity is likely to cause the non-disclosing party pecuniary and competitive damage not easily susceptible to quantification.

3. Unless disclosure is otherwise permitted, each party to a service agreement under this rate must agree not to oppose a legal action by a party that is designed to enjoin or otherwise prevent the other party from disclosing the terms and conditions of such service agreement to a third party.

4. Service agreements may be disclosed to a third party only: a) upon prior written authorization by the parties to the agreement; b) as necessary for the parties to administer and enforce the agreement; c) to an agent, attorney or consultant of either party which has executed an agreement in which it acknowledges the "Highly Confidential and Privileged" nature of the service agreement and agrees to be subject to these Confidentiality/Penalty for Disclosure provisions set forth herein; or d) pursuant to the order of a court of agency having appropriate jurisdiction. Disclosure under b) or d) shall be permitted only after the parties to the service agreement have been provided adequate prior notice and opportunity to prevent such disclosure or to seek an appropriate protective order.

5. Any disclosure by the customer in violation of this provision shall result in a penalty equal to 10% of the otherwise applicable rate for the remaining term of the agreement, or as otherwise set forth in the service agreement.

EXCLUSION OF RATE NGS PURCHASED GAS COSTS FROM SECTION 1307(f) CLAIM

Purchased gas commodity and interstate pipeline demand costs, and associated quantities of natural gas purchased to provide service to customers served under Rate NGS, shall be excluded from the Company's annual purchased gas cost filing under 66 Pa. C.S. § 1307(f), in accordance with Exhibit RAF-1 submitted by the Company at Docket No. R-00016366.

APPLICABILITY INDEX OF RIDERS INTRODUCTORY STATEMENT

Customers under the different rates of this Tariff frequently desire services or present situations and conditions of supply which require special supply terms, charges or guarantees or which warrant modification of the amount or method of charge from the prices set forth in the rate under which they are supplied. Modifications for such conditions are defined by rider provisions included as a part of this Tariff. Riders may be employed when applicable, with or without signed agreement between the Customer and the Company as the case may require.

	PAGE	RATES TO WHICH RIDERS APPLY						
RIDERS	NUMBERS	GR	GC	OL	L	IS	TSI	TSF
Casualty	79	X	X	X	X	X	X	X
Construction	79	-	X	-	X	X	X	X
Neighborhood Gas	80	X	-	-	-	-	-	-
Receivership	82	X	X	X	X	X	X	X
Temporary Service	82	X	X	-	X	-	-	-
Customer Assistance Program	83	X	-	-	-	-	-	-

CASUALTY RIDER

APPLICABILITY. To service delivered during a period when a Customer is prevented for a length of time in excess of 48 hours from using all or a substantial part of the amount contracted for by reason of strike, riot, fire, storm, flood, drought, interference by civil or military authorities, or any other cause beyond the Customer's control.

NOTICE REQUIRED. Written request shall be made to the Company for the application of this rider with advice as to the extent of the interruption, its date, cause and probable duration.

GUARANTEES WAIVED. Guarantees of revenue under the Customer's contract shall be suspended during the period of the interruption, but shall be restored when the cause of interruption shall cease, be removed or remedied.

BILLS PRORATED. Bills for service supplied shall be prorated, based upon the actual level of operation during the period of suspension of guarantees.

RETURN TO NORMAL USE. The Customer shall use reasonable diligence in resuming the use of service provided in the Customer's contract.

TERM. The contract term shall be extended for a period equal to the period of suspension so that the Company shall secure a working term at full connected load equal to the term of the contract.

CONSTRUCTION RIDER

APPLICABILITY. To service supplied during a preliminary operating or construction period while the load is being built up to normal level or during a receding load period after the expiration of a standard contract term while a business is in process of dissolution.

GUARANTEE WAIVED. The guarantee minimum of a contract will be waived during the expanding load period preceding the operation within the load limits provided in the contract or the receding load period subsequent to the fulfillment of a contract term.

RIDER TERM. The total term of application of this rider during the preliminary or construction period shall be 6 months subject to the option of the Company to grant not more than two successive renewals of the rider term on major construction projects. Its application subsequent to the completion of a contract term shall be for not more than one year.

CONTRACT TERM. The termination date of a contract for service to permanent installations to which this rider is applied shall be extended for a period corresponding to the total time of the rider application during start up, construction or extension of the Customer's plant so that the Company will be assured the business represented by service to the total connected load for the term provided in the contract.

NEIGHBORHOOD GAS PILOT RIDER (NGPR)

AVAILABILITY

The Neighborhood Gas Pilot Rider (NGPR) is available to any existing residential neighborhood that: (1) applies for natural gas service within the Company's service territory under Rate Schedules GR or CAP; (2) would be required to pay the portion of the main extension and service line project costs that exceed the Company's capital investment under Rule No. 7 – Extensions of the Company's gas service tariff ("Rule No. 7") for an extension of the Company's distribution facilities needed to furnish natural gas service to a neighborhood; and (3) meets the Program Criteria set forth below.

The NGPR will close for new main extension projects on December 31, 2029 unless the Company decides to extend this program and the extension is approved by the Commission. The Company reserves the right to suspend the pilot program if, in its sole judgment, critical safety or reliability related issues require that the resources that would be used to implement the NGPR are needed to maintain safe and reliable natural gas service to its existing customers. The Company shall be the sole judge in establishing what constitutes a neighborhood when determining the availability under this pilot program.

NATURE OF THE NGPR

The NGPR provides customers in a neighborhood an alternative method of making the payment required by Rule No. 7 when the extension of distribution facilities needed to serve eligible new customers is not economically justified based on the anticipated revenues from natural gas distribution service that would be provided to customers served by such extension. The NGPR provides for a fixed charge (NGPR Charge) to be added to the customer's bill or an option to pay via a lump sum payment. The NGPR Charge shall be calculated separately for each main extension project and shall be based on the cost of that particular project in the manner described below for each customer served from such main extension project.

PROGRAM CRITERIA

For a main extension project to qualify for the NGPR, the neighborhood must consist of 2 or more existing residences, and the cost for such project must equal or exceed $15,000 and must meet the following additional criteria:

(1) A minimum of twenty percent (20%) of the existing residences located along the new main extension must commit to receive natural gas service by signing an agreement prior to the start of construction.

(2) The Company must have adequate system capacity to serve the customers that are eligible to receive natural gas service from the main extension; and

(3) The Company's total investment under this pilot program is limited to no more than $40,000,000 over five (5) years. The five-year extension period that this pilot program is in effect shall commence on January 1, 2025 and, as set forth above, shall close on December 31, 2029.

CALCULATION OF THE NGPR CHARGE

A Net Present Value (NPV) economic test (based on 40 years of revenue for each customer) shall be used to determine the payment required by Rule No. 7.

Pursuant to Rule No. 7, if the NPV of the capital investment (excluding 40 feet gas main allotment per existing residence) and the associated estimated revenues is less than zero, a customer is required to make a payment to the Company in an amount that would produce an NPV of zero, exclusive of any tax on the NGPR For purposes of this NGPR, however, in calculating the NPV, the anticipated revenues from natural gas service shall consist of: (1) the revenues from 20% (or greater) of eligible customers signing a contract prior to the start of construction to take natural gas service in the first year, which is one of the Program Criteria that must be satisfied for a project to be eligible for the NGPR; and (2) additional revenues will be applied in the first year based on the assumption a minimum of 66% of the eligible customers within the project area will sign a contract for natural gas service within 20 years of the completion of the project.

Capital investment shall include the total cost of new main(s) (excluding 40 feet gas main allotment per existing residence) and service facilities installed under the NGPR, excluding the costs of meters and meter installations, to serve eligible customers.

Estimated revenues shall be based on the applicable variable distribution charge rate set forth in the Company's gas service tariff, the estimated annual consumption and the portion of the fixed distribution charge that is attributable to the capital costs of a service line.

NEIGHBORHOOD GAS PILOT RIDER (NGPR) - Continued

Because the NGPR permits payment over time, rather than a lump-sum payment prior to the start of construction of main extension projects, as Rule No. 7 requires, the NGPR Charge will recover a reasonable return on the Company's capital investment in new facilities installed pursuant to the NGPR. For purposes of the NGPR calculation, the discount rate shall be determined on the basis of (1) the Company's capital structure and cost of long-term debt set forth in the Company's latest year-end Quarterly Earnings Report submitted to the Commission by March 31 of a year for the period ending December 31 of the previous year; and 2) the cost of equity approved in the most recent base rate case or, in the absence of a Commission determination or Commission approval of a stipulated cost of equity, the cost of equity that the Commission has determined should apply to Distribution System Improvement Charge ("DSIC") investment.

The NGPR shall be calculated to enable the project to have an NPV of zero based upon the above cost of capital. The resulting charge shall be increased by 1% by dividing the calculated rate by 0.99 to reflect an adjustment for uncollectible accounts expense.

BILLING

The NGPR Charge shall appear as a fixed monthly charge on the customer's bill.

The NGPR Charge calculated for a specific main extension will apply to all customers taking service from that main extension including any future customers that connect after the first year of the project.

For CAP customers, the NGPR charge will not be subject to the CAP discount.

If a customer fails to pay the full amount of any bill, a late payment charge of one and one-half percent (1.5%) per month will accrue on the portion of the bill that is unpaid on the due date.

PAYMENT TERMS

NGPR Charges shall be calculated based on input data specific to each project undertaken pursuant to the NGPR and shall be in effect for 20 years for each customer taking gas service from the main installed under this pilot within 20 years after the project has been completed.

The customer shall retain the right to pay the present value of the remaining monthly payments at any point in time during the 20 year period. Payments shall be present valued using PECO's after-tax cost of capital which shall be based on the sources as described above.

Service shall not be terminated for non-payment of this charge during the pilot program.

The STATE TAX ADJUSTMENT CLAUSE applies to this rider.

RECEIVERSHIP RIDER

APPLICABILITY. To service supplied a Receiver-Trustee for the continued operation of a property formerly under contract for its gas service requirements.

AUTHORITY FOR OPERATION. The Receiver-Trustee shall possess the authority under appointment by Court, through an order duly entered, to operate premises recited in a contract for gas service under which the Company has been supplying gas.

ACCEPTANCE. The Receiver-Trustee shall accept and adopt for the continuation of the supply of gas service the contract therefore in effect, including all of its provisions, and agree to pay the Company for all service furnished hereunder during the receivership-trusteeship at the rate specified therein.

BILLING. The Company reserves the right to render bills on a biweekly basis. To provide for biweekly billing under this rider, the provisions of the applicable rate and rider, if any, will be modified as follows:

(a) Where applicable, all references to monthly or month will be changed to biweekly or biweek.
(b) Where applicable, the commodity charge will be determined on a monthly basis and multiplied by 14/30ths (0.4667).
(c) The monthly rate per lighting device for Rate OL will be multiplied by 0.4667.
(d) The minimum charge will be determined on a monthly basis and such sum will then be multiplied by 0.4667 to determine the minimum charge for the billing period.
(e) A discount of 0.4% will be applied to the total bill.
(f) A bill will be rendered biweekly covering the charges for the preceding billing period and such bill shall be paid within fifteen (15) days after receipt thereof.

CONTRACT TERM. The completion of the term of the contract taken over, or as terminated by the discharge of the Receiver-Trustee, or as arranged with the Receiver-Trustee for the continuation of supply under the standard terms of this Tariff.

TEMPORARY SERVICE RIDER

APPLICABILITY. To the supply of service for a temporary period.

AVAILABILITY. Temporary service will be supplied only when the Company has available unsold capacity from which to furnish it and its supply will not in any way interfere with service to other Customers.

INVESTMENT IN SUPPLY FACILITIES. The cost of the connection and disconnection of the service supply and of any equipment and extension of facilities required to furnish the temporary service under the applicable rate shall be paid by the Customer, but such payment shall not confer upon, nor entitle the Customer to any title to, or right of property in, said facilities and equipment.

MINIMUM TERM. Application of this rider shall not, for billing purposes, be considered to be for a period of less than one month.

CONTRACT TERM. Short term arrangements as agreed upon.

Customer Assistance Program (CAP) Rider

AVAILABILITY:
To payment-troubled customers who are currently served under or otherwise qualify for Rate GR (excluding multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for the rates contained in this rider and must demonstrate annual household gross income at or below 150% of the Federal Poverty guidelines. Customers will be subject to a $20 monthly bill minimum and will not be eligible to obtain Competitive Natural Gas Supply or participate in budget billing.

Based on the applicable level of income and number of household members, CAP customers will receive a fixed bill or Percentage of Income Payment Plan ("PIPP") based upon that individual household's need. The details of the PIPP calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No. M--2018-3005795.

CERTIFICATION/VERIFICATION

Prior to enrollment in the CAP Rider, customers must verify, to PECO's satisfaction, that their household income level meets the "Availability" standards set forth in this Rider. Customers being considered for the CAP Rider will be required to:

- Provide information sufficient to demonstrate to PECO their household income level.
- Waive certain privacy rights to enable PECO to effectively conduct the above certification process.
- Participate in energy reduction and conservation programs offered by PECO if identified as high-usage.

PECO may, at its sole discretion, supplement this verification process by using data from Commonwealth or federal government programs which demonstrate the income eligibility of its customers. Such data may come from a customer's participation in, or receipt of benefits from, the Low Income Home Energy Assistance Program, Temporary Assistance for Needy Families, Food Stamps, Supplemental Security Income, and Medicaid. Information available from the Pennsylvania. Department of Revenue may also be used where appropriate to expedite the process.

MINIMUM CHARGE.
The minimum charge per month will be $20.

ARREARAGE.
Customers who qualify and are enrolled in CAP for the first time will have their pre-program arrearage ("PPA") forgiven if the customer pays his / her new, discounted CAP bill on time and in full each month. With every full and on-time monthly payment, one-twelfth of the PPA will be forgiven. PECO allows for customers who may have missed PPA "forgiveness" due to late or missed payments to "catch-up" on missed PPA forgiveness whenever a customer brings their bill current, PECO will forgive any missed forgiveness the customer did not receive during that time. If the customer develops any in-program arrearage while on the CAP Rate -- that is, if the customer does not pay the entire outstanding balance -- then preprogram arrearage forgiveness will not resume until the first month in which the full outstanding balance is paid.

PECO Exhibit 2:
PECO Gas Tariff No. 7 - Proposed

PECO ENERGY COMPANY

GAS SERVICE TARIFF

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 3.

Issued March 30, 2026 Effective May 29, 2026

.

ISSUED BY: DAVID M. VAHOS - President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE.

LIST OF CHANGES MADE BY THIS SUPPLEMENT

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC) - Original Page No. 41 - Increase budget for Energy Efficiency Plan effective January 1, 2027 and update E factor and offset factor. Methodology added within definition of "Reconcilable CAP Costs" for application of offset factor to reflect only the impacts from changes to CAP participation and PPA forgiveness baselines.

SALES SERVICE COSTS (SSC) – Original Page No. 42 – The Commodity Charges are increased.

GAS PROCUREMENT CHARGE – Original Page No. 45 – The Gas Procurement Charge is increased.

MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – Original Page No. 46 and Original Page No. 47 – The Merchant Function Charges and Write-Off Factors are changed. The Prices to Compare are increased.

PROVISIONS FOR RECOVERY OF CONSUMER EDUCATION COSTS – Original Page No. 50 - Added new H factor

RATE GR - GENERAL SERVICE RESIDENTIAL - Original Page No. 57 – Distribution prices updated.

RATE GC - GENERAL SERVICE COMMERCIAL AND INDUSTRIAL - Page deleted. Effective through December 31, 2025.

RATE GC - GENERAL SERVICE COMMERCIAL AND INDUSTRIAL Original Page No. 58 – Distribution prices updated.

RATE OL- OUTDOOR LIGHTING Original Page No. 59 – Distribution prices updated.

RATE L – LARGE HIGH LOAD FACTOR SERVICE Original Page No. 60 – Distribution prices updated.

RATE MV-F MOTOR VEHICLE SERVICE - FIRM - Original Page No. 61 – Distribution prices updated.

RATE MV-I MOTOR VEHICLE SERVICE - INTERRUPTIBLE Original Page No. 62 – Distribution prices updated.

RATE TS-I GAS TRANSPORTATION SERVICE - INTERRUPTIBLE Original Page No. 73 – Remove the word "maximum" from the Variable Distribution Charge ("VDC") line (under Billing). Distribution prices updated.

RATE TS-F GAS TRANSPORTATION SERVICE FIRM Original Page No. 74 – Remove the word "maximum" from the Variable Distribution Charge ("VDC") line (under Billing). Distribution prices updated.

Applicability Index of Riders Original Page No. 77 – page numbers updated and Weather Normalized Adjustment (WNA) added.

NEIGHBORHOOD GAS PILOT RIDER (NGPR) Original Page No. 79 – Added Transfer of Ownership of the Premises section.

WEATHER NORMALIZED ADJUSTMENT (WNA) Original Page No. 82 –The new WNA will adjust certain customers' bills to reflect normalized weather conditions.

TABLE OF CONTENTS

LIST OF COMMUNITIES SERVED

BUCKS COUNTY:
BOROUGHS: Bristol, Chalfont, Doylestown, Dublin, Hulmeville, Ivyland, Langhorne, Langhorne Manor, Morrisville, New Britain, New Hope, Newtown, Penndel, Telford, Tullytown, Yardley.

FIRST-CLASS TOWNSHIP: Bristol.

SECOND-CLASS TOWNSHIPS: Bedminster, Bensalem, Bridgeton, Buckingham, Doylestown, Falls, Hilltown, Lower Makefield, Lower Southampton, Middletown, New Britain, Newtown, Northampton, Plumstead, Solebury, Tinicum, Upper Makefield, Upper Southampton, Warminster, Warrington, Warwick, West Rockhill, Wrightstown.

CHESTER COUNTY:
CITY: Coatesville.

BOROUGHS: Atglen, Avondale, Downingtown, Elverson, Honey Brook, Kennett Square, Malvern, Modena, Oxford, Parkesburg, Phoenixville, South Coatesville, Spring City, West Chester, West Grove.

FIRST-CLASS TOWNSHIP: Caln.

SECOND-CLASS TOWNSHIPS: Birmingham, Charlestown, East Bradford, East Brandywine, East Caln, East Coventry, East Fallowfield, East Goshen, East Marlborough, East Nantmeal, East Nottingham, East Pikeland, Easttown, East Vincent, East Whiteland, Elk, Franklin, Highland, Honey Brook, Kennett, London Britain, Londonderry, London Grove, Lower Oxford, New Garden, Newlin, New London, North Coventry, Penn, Pennsbury, Pocopson, Sadsbury, Schuylkill, South Coventry, Thornbury, Tredyffrin, Upper Oxford, Upper Uwchlan, Uwchlan, Valley, Wallace, Warwick, West Bradford, West Brandywine, West Caln, West Fallowfield, West Goshen, West Marlborough, West Nantmeal, West Nottingham, West Pikeland, West Sadsbury, Westtown, West Vincent, West Whiteland, Willistown.

DELAWARE COUNTY:
CITY: Chester.

BOROUGHS: Aldan, Brookhaven, Chester Heights, Clifton Heights, Collingdale, Colywn, Darby, East Lansdowne, Eddystone, Folcroft, Glenolden, Haverford, Lansdowne, Marcus Hook, Media, Millbourne, Morton, Norwood, Parkside, Prospect Park, Radnor, Ridley Park, Rose Valley, Rutledge, Sharon Hill, Swarthmore, Trainer, Upland, Yeadon.

FIRST-CLASS TOWNSHIPS: Aston, Darby, Lower Chichester, Marple, Nether Providence, Ridley, Springfield, Tinicum, Upper Chichester, Upper Darby.

SECOND-CLASS TOWNSHIPS: Bethel, Chadds Ford, Chester, Concord, Edgmont, Haverford, Middletown, Newtown, Radnor, Thornbury, Upper Providence,

LANCASTER COUNTY:
BOROUGH: Christiana

SECOND-CLASS TOWNSHIPS: Sadsbury, Salisbury.

MONTGOMERY COUNTY:
BOROUGHS: Ambler, Bridgeport, Bryn Athyn, Collegeville, Conshohocken, East Greenville, Green Lane, Hatboro, Hatfield, Jenkintown, Lansdale, Narbeth, Norristown, North Wales, Pennsburg, Pottstown, Red Hill, Rockledge, Royersford, Schwenksville, Souderton, Telford, Trappe, West Conshohocken.

FIRST-CLASS TOWNSHIPS: Abington, Cheltenham, Hatfield, Lower Merion, Lower Moreland, Lower Pottsgrove, Plymouth, Springfield, Upper Dublin, Upper Gwynedd, Upper Moreland, Upper Pottsgrove, West Norriton, West Pottsgrove.

SECOND-CLASS TOWNSHIPS: East Norriton, Franconia, Horsham, Limerick, Lower Frederick, Lower Gwynedd, Lower Providence, Lower Salford, Marlborough, Montgomery, Perkiomen, Salford, Skippack, Towamencin, Upper Frederick, Upper Hanover, Upper Merion, Upper Providence, Upper Salford, Whitemarsh, Whitpain, Worcester.

HOW TO USE LOOSE LEAF-TARIFF

1. This Tariff is issued on the loose-leaf plan. Each page will be issued as "original page", consecutively numbered, commencing with the title page, which in all cases will be considered as Page No. 1. For example: "Original Page No. 2", "Original Page No. 3," etc.

2. All changes in, additions to, or eliminations from, original pages, will be made by the issue of consecutively numbered supplements to this Tariff and by reprinting the page or pages affected by such change, addition, or elimination. Such supplements will indicate the changes which they effect and will carry a statement of the make-up of the Tariff, as revised. The Table of Contents will be reissued with each supplement.

3. When a page is reprinted the first time, it will be designated under the P.U.C. number as "First Revised Page No...," the second time as "Second Revised Page No. ..." etc. First revised pages will supersede original pages; second revised pages will supersede first revised pages, etc.

4. When changes or additions to be made require more space than is available, one or more pages will be added to the Tariff, to which the same number will be given with letter affix. For example: If changes were to be made in Original Page No. 2 and, to show the changed matter, more than one page should be required, the new page would be issued as "First Revised Page No. 2, superseding Original Page No. 2"; and the added page would be issued as "Original Page No. 2A." If a second added page should be required, it would be issued as "Original Page No. 2B." Subsequent reprints will be consecutively designated as "First Revised...," "Second Revised...," etc.

5. On receipt of a revised page, it will be placed in the Tariff immediately following the page which it is to supersede, and the page which is to be superseded thereby plainly marked "See following page for pending revision." On the date when such revised page becomes effective, the page superseded should be removed from the Tariff.

DEFINITION OF TERMS AND EXPLANATION OF ABBREVIATIONS

Aggregation Services Fee - A charge of 1¢/mcf applicable to all Low Volume Sales and Transportation Customers to be added to such Customers' Variable Distribution Service Charge effective January 1, 2001.

Available rate - A rate which may be obtained by a Customer if the use of service conforms to the character of service contemplated in the rate, and the Customer's location is such that this service can be supplied from existing facilities of the Company.

Bad credit (for deposit purposes) - A customer shall be deemed by the Company to have bad credit if the customer has been delinquent on payment of two consecutive bills or three or more bills in the last twelve billing cycles or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles. Industrial and commercial customers also shall be deemed by the Company to have bad credit if the customer is insolvent, (as evidenced by a credit report prepared by a reputable credit bureau or credit reporting agency or public financial data, liabilities exceeding assets or generally failing to pay debts as they become due) or has a class of publicly-traded debt outstanding that is rated to be below investment grade, or tendered two or more checks that are subsequently dishonored by a payee according to 13 Pa.C.S. §3502, within the last twelve billing cycles.

Balancing Service Cost or ("BSC") – Charge to all Low Volume Customers, both Sales and Transportation, included in Variable Distribution Charges, for fixed and variable storage costs for each Mcf of gas delivered under Rate Schedules GR, CAP, GC, OL, L, and MV-F of this Tariff, or the successors thereto.

British thermal unit (Btu) - The quantity of heat necessary to raise the temperature of one pound of water one degree Fahrenheit from 58.5 to 59.5 degrees Fahrenheit under standard pressure of 30 inches of mercury at or near its point of maximum density. One Btu equals 252 calories, (gram), 778 foot-pounds, 1,055 joules or 0.293 watt hours

Ccf – 100 cubic feet. This is a measure of gas usage.

Chapter 56 – The PUC regulations that govern metering, billing and collections for residential gas and electricity service.

Commodity Charge ("CC") – The "C" factor component of the Sales Service Cost representing the charge to Low Volume Sales Customers for purchased gas costs for each McF of Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff, or the successors thereto.

Commission or PAPUC– The Pennsylvania Public Utility Commission.

Company – PECO Energy Company

Competition Act - the Natural Gas Choice and Competition Act, 66 Pa.C.S. §2201, et seq.

Competitive Natural Gas Supply - firm natural gas provided by an NGS to Low Volume Transportation Customers under the Company's Gas Choice program.

Consolidated NGDC Billing – Billing provided by the Company that contains both the Company's charges for its services and the NGS's separate charges for gas supply services.

Creditworthy - A creditworthy customer pays the Company's charges as and when due and otherwise complies with the Rules and Regulations of this Tariff or the PaPUC. To determine whether a customer is creditworthy with respect to a particular account, the Company will evaluate the customer's record of paying Company charges for all of the customer's other Company accounts, and may also take into consideration the customer's general credit.

cu. ft. - Cubic foot.

Customer - Any person, partnership, association, or corporation, lawfully receiving service at a single meter location from the Company. In addition, unless explicitly prohibited by the Public Utility Code or the Commission's Rules or Regulations, an NGS may act as an agent for a Customer upon written authorization to PECO Energy, which authorization may be included in the notice of NGS selection.

Daily quantity - The quantity of gas used in a 24-hour period beginning at 10:00 a.m., Eastern Standard Time or Daylight Savings Time, whichever is in common use.

Delivery point - That point at which the Customer's facilities are connected to the Company's facilities which is typically the first fitting after the outlet side of the meter connection. or in certain cases the first fitting after the outlet side of the regulator or relief valve if located downstream of the meter.

Firm Service - Natural gas service offered to Customers under tariffs or contracts that anticipate no interruption of natural gas service.

Fixed Distribution Service Charge – A charge to recover costs caused by the presence of the Low Volume Customer on the system, other than the costs associated with the Customer's usage.

Gas Choice – Program under which Suppliers provide Competitive Natural Gas Supply to Low Volume Transportation Customers.

Gas Cost Adjustment ("GCA") Charge – The "E" factor component of the Sales Service Cost representing the net overcollection or undercollection of purchased gas costs, charged to Low Volume Sales Customers for each Mcf of Sales Service gas supplied under Rate Schedules GR, GC, CAP, OL L, and MV-F or the successors thereto.

High Volume Transportation (HVT) - PECO Energy's Gas program as administered by this tariff for Suppliers providing Competitive Natural Gas Supply to High Volume Transportation Customers.

High Volume Transportation Customers - Customers who purchase natural gas from an alternative Supplier under Rates Schedules TS-F, TS-I and/or the successors thereto, and not under the Company's Gas Choice program.

Holidays - New Year's Day, Martin Luther King, Jr.'s Birthday, Presidents' Day, Good Friday, Memorial Day, Juneteenth, Independence Day, Labor Day, Columbus Day, Veterans Day, Thanksgiving Day, Friday after Thanksgiving, Christmas, and Sundays

Initial Contract Term - The Customer's initial contract term, or in the case of transportation service, any renegotiation of an existing contract, for a service location shall be the Customer's first term of contract for service as specified under a given tariff rate or contract agreement to a location and shall also be the first term of contract after the Customer changes service at a location to a different rate, or in case of transportation service, any renegotiation of an existing contract.

Low Volume Customers – Customers served under Rate Schedules GR, GC, CAP, OL, L, and MV-F or successors thereto.

Low Volume Sales Customer – Low Volume Customers served under Rate Schedules GR, GC, CAP, OL, L, and MV-F who purchase their gas from the Company.

Low Volume Transportation Customers ("LVT Customers") - Low Volume Customers who purchase Competitive Natural Gas Supply from a Supplier pursuant to the Company's Gas Choice program, under Rates Schedules GR, GC, OL, MV-F or the successors thereto, and not under Rate Schedules CAP, L, TCS, IS, MV-I, TS-F, TS-I, and/or the successors thereto.

Master Meter System - a pipeline system for distributing gas within, but not limited to, a definable area, such as a mobile home park, housing project, or apartment complex, where the operator purchases metered gas from an outside source for resale through a gas distribution pipeline system. The gas distribution pipeline system supplies the ultimate consumer who either purchases the gas directly through a meter (i.e., Master Meter) or by other means, such as by rents.

Mcf – 1,000 cubic feet. This is a measure of gas usage.

Month - A month under this Tariff means 1/12 of a year, or the period of approximately 30 days between two regular consecutive meter readings dates of the Company's meter or meters installed on the Customer's premises.

Natural Gas Distribution Company ("NGDC") - a public utility that owns natural gas distribution facilities, used at times in this Tariff to refer to the role of the Company as the distributor of Competitive Natural Gas Supply pursuant to the Competition Act.

Natural Gas Supplier ("Supplier" or "NGS") - A natural gas supplier as defined in 66 Pa.C.S. § 2202, that has been licensed by the Pennsylvania Public Utility Commission to sell Competitive Natural Gas Supply to Low Volume Transportation Customers on the Company's system under the Company's Gas Choice program, to sell natural gas to Customers under Rates TCS, IS and/or MV-I or to sell natural gas to High Volume Transportation Customers under Rate Schedules TS-F, TS-I, and/or any other entity that takes title to gas as defined in 52 Pa. Code § 62.101

Natural Gas Supplier Coordination Tariff – The Tariff, setting forth the basic requirements for interactions and coordination between the Company, as the natural gas distribution company, and Suppliers necessary for maintaining the delivery of Competitive Natural Gas Supply from Suppliers to their Low Volume Transportation Customers under the Company's Gas Choice program.

Principal Office - The Company's Main Office Building located at 2301 Market Street, Philadelphia, Pa. 19103.

Property line - The division line between land held in, or for, private use, and land in which the public or the Company has a right of use; or the division line between separately owned or occupied land.

Sales Service Cost ("SSC") - Cost of commodity and non-storage interstate pipeline firm transportation capacity to delivery such commodity to the city gate for Low Volume Sales Customers.

Rate - The rates are CAP, GR, GC, OL, L, MV-F, MV-I, IS, TCS, TS-I, TS-F, and NGS or the successors thereto.

Separate NGS Billing ("Dual Billing") – Separate Billing by an NGS of its charges for gas supply service.

Service - The distribution of gas for use by the Customer, including all things done by the Company in connection with such distribution.

Service-Supply Pipe - The pipe extending from the Company's supply main to a metered delivery point or, in the case of installations comprised exclusively of outdoor gas lights, to the first such light.

Summary Billing Accounts - An aggregate bill prepared at the option of the Company for Customers with multiple accounts that are related within the same partnership, association, corporation or governmental agency.

Supplier of Last Resort Service ("SLR Service" or "Sales Service") - Natural gas supply service provided by the Company as supplier-of-last-resort to residential, small commercial, small industrial and essential human needs Customers who: (1) do not choose a Supplier or chose to be served by their supplier of last resort; (2) who are refused service by a Supplier; (3) whose Supplier has defaulted or exited the system; or (4) who return to SLR service after having obtained Competitive Natural Gas Supply.

System Maintenance Order ("SMO") – operational directive issued by the Company in its sole discretion to protect the operational integrity of its systems in terms of line pressure and adequacy of supply, which orders directly affect the quantity of gas to be delivered on the same gas day or other near-term gas days and may require a Customer or class of Customers, or a Customer's natural gas supplier or agent, to maintain, decrease or increase the quantity of natural gas delivered to the Company's system.

Tariff – This Gas Service Tariff comprising the rates, rules and regulations that apply to the distribution of natural gas, including all things done by the Company in connection with such distribution and/or the supply of natural gas under Supplier of Last Resort (Sales) Service.

Transportation Service – Natural gas supply service provided to HVT Customers, by an alternative Natural Gas Supplier as further detailed in Rule 1.1 of the Gas Transportation Service General Terms and Conditions Section of this Tariff.

Variable Distribution Service Charge – The variable charges on a Mcf basis for the provision of unbundled distribution service, including all things done by the Company in connection with such distribution service.

Volume Adjustment - the current adjustable factor applied to all rate classes to account for: a) reduction for system losses of 3.3% and b) thermal correction, the latter being determined by dividing the daily average Btu content per cubic foot of gas for the Company's system by a reference Btu content of 1,000 Btu per cubic foot.

RULES AND REGULATIONS

1. THE GAS SERVICE TARIFF

1.1 FILING AND POSTING. A copy of this Tariff, which comprises the Rates, Rules and Regulations under which service and SLR (Sales) Service will be supplied to its Customers by PECO Energy Company, is on file with the Pennsylvania Public Utility Commission and is posted and open to inspection at the Principal Office of the Company. A copy of this Tariff also is available on the Company's website at: peco.com

1.2 REVISIONS. This Tariff may be revised, amended, supplemented or otherwise changed from time to time in accordance with the Pennsylvania "Public Utility Law", and such changes, when effective, shall have the same force as the present Tariff.

1.3 APPLICATION. The Tariff provisions apply to everyone lawfully receiving service from the Company, under the rates therein, and receipt of service shall constitute the receiver a Customer of the Company as the term is used herein, whether service is based upon contract, agreement, accepted signed application, or otherwise. A Customer will receive service under this Tariff effective with their first scheduled billing cycle beginning after July 1, 2000.

1.4 BASIS OF CHARGE. Time elapsed is a factor in the supply of service and the rates and minimum charges named in this Tariff, while predicated on periods of supply of not less than one year, are stated in values for direct application only to monthly periods of service provision and will be adjusted for application to service provided during other time intervals.

1.5 RULES AND REGULATIONS. The Rules and Regulations, filed as a part of this Tariff, are a part of every contract for service made by the Company and govern all classes of service where applicable, unless specifically modified by a rate or rider provision. The obligations imposed on customers in the Rules and Regulations apply as well to everyone receiving service unlawfully and to unauthorized use of service.

1.6 USE OF RIDERS. The terms governing the provision of service under a particular rate may be modified or amended only by the application of standard riders, filed as part of this Tariff.

1.7 STATEMENT BY AGENTS. No representative has authority to modify a Tariff rule or provision, or to bind the Company by any promise or representation contrary thereto.

RULES AND REGULATIONS - Continued

2. SERVICE SPECIFICATIONS

2.1 CHARACTER. This Tariff applies only to the distribution and/or supply of natural gas, or its equivalent. Supply pressures will be limited in accordance with Company specifications.

2.2 SINGLE-POINT DELIVERY. The rates named in this Tariff are based upon the Company’s distribution and/or supply through a single delivery point. Separate distribution and/or supply for the same Customer at other points of delivery shall be billed separately unless otherwise specifically provided for under a rate or rider statement.

2.3 SINGLE-POINT AVAILABILITY. Service delivered at a single point is available to one or more buildings or units devoted essentially to a single purpose, provided and so long as:

a. Such buildings or units are:
   (1) held, possessed, and either utilized or operated as a single establishment by a single responsible entity, and
   (2) unified on the basis of family, business, industry, enterprise, or governmental agency or through conveniences and services, such as heat, elevator, janitor, care of halls, walks and lawns, etc., furnished by such entity, and
   (3) situated on a single or on contiguous land parcels except where such buildings or units constitute interdependent parts of a single industrial enterprise. In determining "contiguity" hereunder of parcels abutting opposite sides of public or private ways, the boundaries of such parcels shall be considered as extending to the center of such ways.

b. There is granted and maintained to the Company easement or other rights, adequate in the Company's reasonable judgment to supply service direct to any such buildings or units if, as and when a cessation of any one or more of the conditions stated in paragraph lettered "a" above should occur, or there should arise in any manner a Company duty of such direct supply.

c. The distribution and other facilities on the Customer's side of the delivery point are:
   (1) furnished, installed and maintained at the expense of the Customer, and
   (2) owned or leased by the Customer, and
   (3) operated and controlled by or at the expense of the Customer.

d. The Company is under no legal obligation of direct supply to any portion of said buildings or units or their appurtenances.

e. A guarantee by deposit or otherwise is given and maintained to the Company sufficient in its reasonable judgment to insure it against loss in distribution and other investment in the event of change in the nature of holding and possession of such buildings or units, or in the occupancy thereof, or in the type of service delivered thereto.

f. All utilization equipment on the Customer's side of the Company delivery point is furnished, installed, operated and maintained by the operator of the buildings or units supplied or by the tenants of such operator whose use of gas is dependent upon the single point delivery and metering of service.

g. Any use of public highways by such operator for the latter's distribution facilities does not conflict or interfere with the franchise rights of the Company.

2.4 COMPLIANCE WITH AVAILABILITY. The use of the Company's service shall not be for any purpose other than that covered by the availability provisions of the rate or rider under which service is supplied.

2.5 COMPLIANCE WITH BUILDING ENERGY CONSERVATION ACT STANDARDS. Prior to furnishing permanent residential service for heating or cooling purposes to new residential buildings, a copy of the Compliance Certification from the Pennsylvania Department of Community Affairs indicating proof of compliance with, or exemption from, the insulation standards set forth in the Building Energy Conservation Act and the regulations promulgated thereunder, will be required for residential buildings located in municipalities that have not elected to administer the Act.

RULES AND REGULATIONS - Continued

3. CUSTOMER'S INSTALLATION

3.1 INFORMATION FROM APPLICANT FOR SERVICE. The Company should be advised by the applicant for service in writing, preferably on a form supplied by the Company, of premises to be equipped for gas, giving exact location, and details of all gas appliances to be installed.

The applicant for service shall supply the Company information regarding potential or actual contamination, waste or other materials or other adverse environmental conditions on the Customer's premises on or near where the Company facilities are to be located. The Customer has a continuing obligation to provide the Company with copies of any environmental assessment relating to the premises. The Company also has a continuing right to inspect the Customer's premises for the purposes of performing an environmental assessment.

3.2 DELIVERY POINT. The Company will designate in writing, upon request, a satisfactory point at which the Customer shall terminate the Customer's piping for connection to the facilities of the Company. The failure to request and obtain such information may result in refusal of service pending rearrangement of Customer's facilities, but the designation of a termination point does not constitute an agreement or obligation on the part of the Company to furnish service.

In establishing a point of delivery, the Company has the right to avoid areas known or suspected to contain contamination waste or other materials or other adverse environmental conditions.

The Company may waive this right upon agreement from the Customer or applicant to indemnify, defend and hold harmless the Company (its successors, assigns, trustees, officers, employees and agents) from and against all actions, causes of action, claims and demands whatsoever, and from all costs, damages, expenses, losses, charges, debts and liabilities whatsoever (including attorney's fees), whether known or unknown, present or future, that arise from such conditions. This indemnification provision shall survive the termination or expiration of this Agreement and the termination of the business relationship of the parties hereto.

3.3 METER LOCATION. There shall be provided, free of expense to the Company, at a location outdoors, unless otherwise designated by the Company, which the Company will designate in writing upon request, a suitable place for the regulator or regulators, meter or meters, and any other supply, protective or control equipment of the Company which may be required in the delivery of gas service. Meters and regulators must be located outside and above ground in accordance with 52 Pa. Code § 59.18. However, meters and service regulators cannot be installed in locations specified in 52 Pa. Code § 59.18(a)(8)(i-vi). Inside meter and service regulator locations shall be considered by the Company, but only in accordance with the exceptions contained in 52 Pa. Code §59.18(d). The Company may also consider other meter or regulator locations (such as a specially constructed cabinet recessed in the building wall, sealed from inside the building and vented to and accessible from outside the building) per 52 PA Code §59.18(e). The customer shall provide access (see Rule 10.5) and space, in an amount deemed necessary by the Company, to install and maintain its meter(s) and equipment. This location shall be convenient, unimpeded and easily accessible to the Company's employees, contractors and agents. The Customer shall also minimize any risk for damage and/or harm to the Company’s employees, contractors, agents and equipment at the meter location. There also must not be any impediment or obstruction of the Company’s ability to receive, an adequate communication signal from its meter(s) for remote reading purposes. The meter(s) location also shall be situated so that the meter(s) are not concealed, but shall be situated in a manner acceptable to the Company.

3.4 NONSTANDARD SERVICE. The Customer shall pay the cost of any special installation necessary to meet any peculiar requirements for service.

The Customer shall pay all costs to the Company of performing environmental assessments, including consultant costs and the costs of removal and disposal of hazardous materials associated with either the initial installation of service, modifications to the service or repair and maintenance of service.

3.5 REVERSE FLOW. The Customer may be required to install check-valves, or other devices, to prevent compressed air or other gases from entering the Company's mains.

3.6 EXCESS FLOW VALVES (“EFVs”). For new and replaced service line installations, the Company will install an Excess Flow Valve (EFV) at its own expense pursuant to 49 C.F.R. § 192.383, (defined in § 192.383(a), as required in (b) with exceptions in (c)). Eligible customers who request installation of an EFV on existing service lines (per § 192.383(d)), must pay the installation costs before any work begins.

RULES AND REGULATIONS - Continued

4. APPLICATION FOR SERVICE

4.1 METHOD OF APPLICATION. Customers may apply for service via the Company's website at http://www.peco.com or, in some cases, over the telephone.

4.2 SERVICE CONTRACT. Every applicant for service may be required to sign a contract, agreement, or other form, then in use by the Company, covering the special circumstances of the use of gas, and shall abide by these Rules and Regulations and the standard requirements of the Company.

4.3 CONTRACT DATA. The application shall contain a statement of the premises to be served, the rate under which service is desired, and such conditions or riders as are applicable to the special circumstances of the case.

4.4 RIGHT TO REJECT. The Company may place limitations on the amount and character of service it will supply or may reject applications for service not available under a standard rate, or which might affect the supply of service to other Customers, or to be delivered at a location which involves excessive cost; for bad credit; for the applicant's' failure to provide identifying documentation; when an applicant's self-identification cannot be verified; or for other good and sufficient reasons. Customer can be denied SLR (Sales) Service or new service for failure to pay an NGS's charges.

The Company has the right to restrict service to only those locations which will not expose the Company to liability for known or suspected contaminated waste or materials or other adverse environmental conditions.

4.5 ACCEPTANCE. When an application is accepted, or when service is supplied according thereto either without modification or with supplemental agreement, it constitutes the contract between the Customer and the Company, subject to the Rules and Regulations.

4.6 SPECIAL CONTRACTS. Standard contracts shall be for terms as specified in the statement of the rate, but where large or special investment is necessary for the supply of service, or where service is to be used for an emergency or temporary replacement of another method of operation, contracts of longer term than specified in the rate, or with special guarantees of revenue, or both, may be required.

4.7 UNAUTHORIZED USE. Unauthorized connection to the Company's service-supply facilities, and/or unauthorized use of utility service, may be terminated by the Company without notice. Unauthorized use of utility service means unreasonable interference or diversion of service, including meter tampering any act which affects the proper registration of service through a meter, by-passing (unmetered service that flows through a device connected between a service line and Customer-owned facilities), and unauthorized service restoral. In cases of tampering or by-passing, the use of service without notifying the Company and enabling it to read its meter will render the user liable for any amount due for service supplied to the premises from the time of the last reading of the meter, immediately preceding the Customer's occupancy, as shown by the Company's books.

4.8 WITHDRAWAL OF APPLICATION BY NON-RESIDENTIAL CUSTOMERS. In the event the Customer or potential Customer withdraws, in whole or in part, an application for either new or modified service, the Customer will reimburse the Company for all reasonable costs incurred by the Company in anticipation of supplying the new or modified service where such costs were described by the Company to the Customer at or before the time application was made. This provision does not apply to individual residential service applicants.

RULES AND REGULATIONS - Continued

5. CREDIT

5.1 PAYMENT OBLIGATION. The provision of service for any purpose, at any location, is contingent upon payment of all charges provided for in this Tariff as applicable to the location and the character of service.

5.2 PRIOR DEBTS. Service will not be furnished to applicants or former customers until any indebtedness to the Company for previous service of the same or similar classification has been satisfied or a payment arrangement has been made on the debt. The Company may, at its discretion, determine liability for prior debts or past due balances by: (1) the use of company records that contain information provided to the Company; (2) information contained on a valid mortgage, lease, deed or renter's license; (3) the use of commercially available public records databases; (4) Government and property ownership records. This rule does not apply to the disputed portion of disputed bills under investigation. The Company will apply this rule to the disputed portion of disputed bills, if, and only if: (1) the Company has made diligent and reasonable efforts to investigate and resolve the dispute; (2) the result of the investigation is that the Company determines that the customer's claims are unwarranted or invalid; (3) the Commission and/or the Bureau of Consumer Services has decided a formal or informal complaint in the Company's favor and no timely appeal is filed; and (4) the customer nevertheless continues to dispute the same matter in bad faith.

5.3 GUARANTEE OF PAYMENTS. The Company may charge a security deposit before it will render service to an applicant or before the Company will continue to render service to a customer for whom the Company provides Consolidated EDC Billing or Separate EDC Billing. The Company may charge deposits to applicants and customers if they have bad credit, lack creditworthiness or as otherwise permitted by Commission statutes, rules, regulations, and as required by Federal Bankruptcy Law. The applicant or customer may be required to provide a cash deposit, letter of credit, surety bond, or other guarantee, satisfactory to the Company. The Company will hold the deposit as security for the payment of final bills and in compliance with the Company's Rules and Regulations. In addition, the Company may require industrial and commercial customers to post a deposit at any time if the Company determines that the customer is no longer creditworthy or has bad credit or as otherwise permitted by Commission statutes, rules, regulations and as required by Federal Bankruptcy Law. The Company retains the right to charge customers additional deposits based upon continued bad credit or lack of creditworthiness and increased usage.

5.4 AMOUNT OF DEPOSIT. For residential customers the deposit will be equal to one-sixth of the applicant's or customers estimated annual bill for Company charges, based on applicable rates. A deposit from a residential customer shall conform to the requirements of 66 Pa. C.S. 1404(c) and applicable Pennsylvania Public Utility Commission regulations. For industrial and commercial accounts, the amount of the deposit shall be the Company's projection of the sum of the Company charges in the customer's two highest monthly bills in the 12 months following the deposit. The provisions of 11 U.S.C. §366(b) of the Federal Bankruptcy Code, or any successor statute or provision, shall, if inconsistent, supersede the provisions of this rule. Deposits required by the Company for Tariff regulated charges shall not be based on unpaid supplier charges.

. 5.5 RETURN OF DEPOSIT Deposits secured from a residential Customer shall be returned with accrued interest, in accordance with 66 Pa. C.S.§1404(C) and applicable Pennsylvania Public Utility Commission regulations In cases of discontinuance of service, deposits will be returned with accrued interest upon payment of all service charges and guarantees or with deduction of unpaid accounts. Effective July 1, 2011, PECO will return the deposit on a non-residential account if the account was assessed fewer than two late payments in the previous 24 months. The first annual review of the customer's payment status will occur 24 months after the initial deposit date. Any residential or commercial customer having secured the return of a deposit may be required to make another deposit, in accordance with Commission statutes, regulations, or Federal Bankruptcy Law, if the Customer demonstrates bad credit or lacks creditworthiness subsequent to the return of the initial deposit.

5.6 INTEREST ON DEPOSIT. The Company will allow simple interest on cash deposits calculated as follows:

(1) with respect to residential accounts:

- (a) interest accrued prior to December 14, 2004, at an annual rate determined by the average of the 1-Year Treasury Bills for September, October and November of the previous year ("Interest Index");
- (b) interest accrued on or after December 14, 2004, at an annual rate determined by the legal rate of interest pursuant to 66 Pa. C.S.A. § 1404(C)(6);

(2) with respect to commercial and industrial accounts, at the lower of the Interest Index or six percent; provided that interest accrued prior to April 14, 1995 shall be calculated at six percent. Deposits shall cease to bear interest upon discontinuance of service (or, if earlier, when the Company closes the account).

5.7 CREDIT INFORMATION.

CUSTOMERS: In addition to information required otherwise hereunder, customers for whom the Company provides Consolidated NGDC Billing or Separate NGDC Billing shall be required to provide to the Company with such credit information, as the Company requires. The Company may report to a national credit bureau on credit history associated with past due amounts.

APPLICANTS: The Company's credit and application procedures for applicants are as follows: (1) positive identification of applicant obtained from previous customer record or through one of the major credit reporting bureaus; (2) determination of liability for a past due balance; (3) determination if a deposit is required based upon applicant's previous account history if available or through third party credit scoring of applicant.

The Company's credit scoring methodology and standards are as follows: The Company uses a commercially recognized credit scoring methodology that is within the range of generally accepted industry practice. The applicant's or customer's utility payment history determines the credit score. The Company uses this customer-specific credit score to either request or waive a security deposit.

RULES AND REGULATIONS - Continued

6. SERVICE-SUPPLY FACILITIES

6.1 COMPANY'S SERVICE-SUPPLY PIPE. The Company will install, own and maintain the required service-supply pipe with Company participation in the cost of installation determined by the Company in accordance with Section 7 Extensions.

6.2 SERVICE-SUPPLY ALTERATIONS. Changes in location of service-supply pipe, or meter and connections, for the accommodation of the Customer, shall be at the expense of the Customer. A customer or building owner requesting that a meter or regulator be moved shall pay the costs associated with relocation when the meter and regulator are currently situated in a suitable location under State and Federal regulations per PA 52 Code § 59.18(a)(11).

6.3 STUB-SERVICE PIPE. When supply mains are in place, service-supply pipe to a point beyond the curb line may be installed, at the option of the Company, ahead of paving, providing the owners of the abutting property shall request and pay for such stub-service pipe. The cost of any such stub-service pipe may be refunded to the Customer over a term of years, upon such basis or condition as may be determined by the Company and specified in the contract for service.

6.4 METERS AND REGULATORS. The Company will provide, own and maintain any meter or meters, regulator or regulators, required in the supply of service.

7. EXTENSIONS

7.1 SUPPLY MAIN CONSTRUCTION. The Company will install, own and maintain gas supply mains located on the highway or on rights-of-way acquired by the Company and used or usable as part of the Company's general supply system.

7.2 OBLIGATION TO EXTEND. Subject to the terms set forth herein, the Company will extend its facilities to a new point of delivery without charge to a potential customer making a valid request for natural gas service. For additional details see Section 7.3, Service Pipe and Main Extension Policy.

7.3 SERVICE PIPE AND MAIN EXTENSION POLICY. When gas is available for sale to new customers under one of the Company's firm sales or transportation rate schedules, main and service facilities will be extended to an applicant in accordance with the following provisions:

A. General Economic Test. For firm service customers the Company will make a capital investment in the total cost of new main and service facilities to serve the customer (including, but not limited to, allocated overheads and related system modifications) when the net present value (NPV) from a proposed project is greater than or equal to zero. Net present value shall be calculated based on the capital investment, exclusive of the costs of meter and meter installation, required to serve the applicant(s) and the estimated base annual revenues (EBAR) generated from the applicant(s). The "EBAR" shall be calculated by multiplying the applicable Variable Distribution Charge rate (excluding any applicable gross receipts tax or certain fixed TCS costs) times the estimated annual consumption, plus the portion of annualized Fixed Distribution Charge attributable to service line capital costs. In calculating the NPV, the following assumptions will be made: 1) a 40 year evaluation period, 2) the discount rate shall be the Company's after–tax cost of capital, 3) revenue shall be assumed to be collected throughout the year, and 4) capital is assumed to be invested at the beginning of the year. If the proposed project has a negative NPV, the Customer shall make a payment to bring the net present value to a zero value. This will enable the proposed project to support a reasonable rate of return to the Company.

B. Developments. Payments shall be required in advance for all lot developments. If a payment is required, the amount of payment shall be based on the General Economic Test set forth in Section 7.3A and shall incorporate known gas applications in buildings under construction or buildings not yet under construction but which are expected to be fully constructed within a five year period from the date of the original contract signing. This requirement may alternatively be satisfied by payment of at least 35 percent of the required contribution upon execution of the service agreement with the remainder subject to payment bond and interest (at prime rate) and is due no later than 6 months after PECO certifies, in writing, that service is available to the development. At the time of execution of the service agreement, the developer shall also post a letter of credit, surety bond, or other security, satisfactory to the Company equal to 50% of the value of the revenue stream as calculated by the Company under Section 7.3A. If the developer does not fully develop the lots within five years, including, but not limited to, installing all required appliances and flowing natural gas to them, the Company reserves the right to use the security as payment for the contract amount. Lot developments are defined as tracts subdivided for sale as individual lots or groups of lots to more than one builder or buyer.

C. Interruptible Service Installations. The Company will make a capital investment in the total cost of new main, service facilities and dual fuel installations, (including, but not limited to allocated overheads and related system modifications) to serve Customers with interruptible service installations, up to an amount equal to three times the additional Estimated Base Annual Revenue (EBAR) attributable to the Customer. The Customer shall pay the cost, if any, in excess of the above limit exclusive of the costs of the meter and, meter installation.

D. After-tax cost of capital (discount rate) shall be determined on the basis of (1) the Company's capital structure and cost of long-term debt set forth in the Company's latest year-end Quarterly Earnings Report submitted to the Commission by March 31 of a year for the period ending December 31 of the previous year; and 2) the cost of equity approved in the most recent base rate case or, in the absence of a Commission determination or Commission approval of a stipulated cost of equity, the cost of equity that the Commission has determined should apply to Distribution System Improvement Charge ("DSIC") investment.

7.4 EXTENSION REFUNDS. Upon receipt of a written request by a Customer or developer made no earlier than the end of the third year following the date of an agreement for new gas service, PECO will: (a) review its records to determine if a refund is due the customer or the developer for additional customers beyond those used to calculate the projected revenue stream as determined in the General Economic Test above that attached to the facilities paid for by the customer or the developer within three (3) years after the execution date of the agreement for new gas service, and (b) within sixty (60) days of receipt of such request, (i) make payment to the customer or developer of any refund due and (ii) provide the customer or developer with documentation substantiating the refund calculations and identifying the attached loads for which the developer was credited. Customer or developer contributions may be refunded if, within three years of the date of the service agreement, new loads are added to facilities paid for by the contributing Customer or developer. Revenue and cost computations shall simulate that the original and new loads were installed at the same time. Refunds will be paid only to the contributing Customer or developer, and the original contribution shall be the maximum refund.

7.5 TAX ACCOUNTING OF CONTRIBUTIONS IN AID OF CONSTRUCTION AND CUSTOMER ADVANCES. All contributions in aid of construction (CIAC), customer advances or other like payments received by the Company shall constitute taxable income as defined by the Internal Revenue Service. The income taxes on such CIAC or customer advances will be segregated in a deferred account for inclusion in rate base in a future rate case proceeding. Such income taxes associated with CIAC or customer advances will not be charged to the specific contributor of the capital.

RULES AND REGULATIONS - Continued

8. RIGHTS-OF-WAY

8.1 TERM AND RENTALS. When the premises of a Customer is so located that the Customer can be served only by facilities extending over the property of another, the Customer shall accept service for such term as is provided in the permit or agreement covering the location and the maintenance of service equipment, and the Customer shall reimburse Company for any and all special or rental charges that may be made for such rights by said permit or agreement.

8.2 PROCUREMENT BY CUSTOMER. Customers applying for the construction of an extension may be required to secure to, and for, the Company, all necessary and convenient rights-of-way and to pay the costs incident thereto.

8.3 DELAYS. Applications for service from an extension to be constructed where a right-of-way is not owned by the Company will only be accepted subject to delays incident to obtaining a satisfactory right-of-way.

9. INTRODUCTION OF SERVICE

9.1 COMPANY'S RIGHT TO INSPECT. The Company shall have the right, but shall not be obliged, to inspect any installation before service is introduced or at any later time, and reserves the right to reject any piping or appliances not in accordance with the Company's standard requirements; but such inspection, or failure to inspect, or to reject, shall not render the Company liable or responsible for any loss or damage, resulting from defects in the installation, piping, or appliances, or from violation of Company rules, or from accidents which may occur upon the premises of the Customer.

9.2 DEFECTIVE INSTALLATION. The Company may refuse to connect if, in its judgment, the Customer's installation is defective, or does not comply with such reasonable requirements as may be necessary for safety or is in violation of the Company's standard requirements.

9.3 UNSATISFACTORY INSTALLATION. The Company may refuse to connect if, in its judgment, the Customer's equipment, or use thereof, might injuriously affect the equipment of the Company, or the Company's service to other Customers.

9.4 INITIAL SERVICE. In all cases gas shall be introduced to the Customer's installation by, or under the supervision of, a representative of the Company.

RULES AND REGULATIONS - Continued

10. COMPANY EQUIPMENT

10.1 COMPANY MAINTENANCE. The Company shall keep in repair and maintain its own property installed on the premises of the Customer.

10.2 CUSTOMER'S RESPONSIBILITY. The Customer shall be responsible for safekeeping of the Company's property while on the Customer's premises. In event of injury or destruction of any such property the Customer shall pay the costs of repairs and replacement. Any changes made to the Customer's premises after the Company completes its service and meter installation that, in the opinion of the Company, creates an unsafe condition, shall be the Customer's responsibility to pay any costs associated with remedying the unsafe condition including but not limited to any required protective measures and/or relocations of Company property. Customers with privately owned or operated underground utility facilities on their premises may have obligations as facility owners under the Underground Utility Line Protection Act, 73 P.S. Section 176 et. seq. These include becoming a member of Pennsylvania One Call, maintaining said facilities, and providing approximate locations of said facilities with temporary markings within the required time period in response to Pennsylvania One Call notifications. Customers should create and retain as-built drawings reflecting the locations of said facilities on the premises and revise these drawings as necessary to reflect any changes made following installation. If said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work, the Company has the right to require the associated customer to bear all incremental costs necessary to ensure safe digging by the Company, including but not limited to subsurface utility excavation and engineering, materials, supplies, transportation, labor, and overhead. If 1) said facilities are insufficiently marked prior to the lawful start date of any Company excavation or construction work or 2) the Company is unable to notify a facility owner of its intent for excavation or similar work covered under the Act because the facility owner is not a member of the Pennsylvania One Call system, the Company shall not be liable to customers or any other third parties for any damages, including property damage, economic damages, costs, associated consequential damages or personal injuries.

10.3 PROTECTION BY CUSTOMER. The Customer shall protect the equipment of the Company on the Customer's premises, and shall not permit any person, except a Company employee having a standard badge of the Company or other Company identification, to break any seals upon, or do any work on, any meter, service-supply pipe or other equipment of the Company located on the Customer's premises.

10.4 TAMPERING. In the event of the Company's meters or other property being tampered or interfered with, the Customer being supplied through such equipment shall pay the amount which the Company may estimate is due for service used but not registered on the Company's meter, and for any repairs or replacements required, as well as for costs of inspections, investigations, and protective installations.

10.5 RIGHT OF ACCESS. The Company's identified employees shall have access to the premises of the Customer at all reasonable times for the purpose of reading meters and disconnecting service, and for installing, testing, inspecting, repairing, removing or changing any or all equipment belonging to the Company. See 52 Pa. Code § 59.24.

10.6 OWNERSHIP AND REMOVAL. All equipment supplied by the Company shall remain its exclusive property, and the Company shall have the right to remove the same from the premises of the Customer at any time after the termination of service from whatever cause.

10.7 RELOCATION OF COMPANY FACILITIES REQUESTED BY NON-RESIDENTIAL PROPERTY OWNERS. Except as otherwise provided by law (e.g., 66 Pa. C.S. Section 2704 et seq.), a non-residential property owner, such as a builder, developer or contractor (Owner), shall compensate the Company for the costs of relocation of Company facilities or equipment, made for the accommodation of the Owner or in fulfillment of the Owner's obligation to any public authority.

If the facility relocation is made to accommodate the Owner's project or in fulfillment of the Owner's obligation to any public authority, then the Owner shall be responsible to pay PECO for the relocation costs even if the relocation request is made by an entity other than the Owner. A request for relocation of Company facilities shall be in writing. The relocation cost shall include labor (including overhead), materials, storeroom expense and transportation, less the depreciated value of any equipment replaced.

Where the relocation is done in conjunction with construction of a supply line to a development, the Company shall include in the relocation cost those costs caused by the Owner's request. Such relocation costs are not part of the capital investment toward supplying service and are, therefore, not included in the revenue test with which the line extension contribution is calculated.

The Company will notify the Owner in writing of the relocation cost. Advance payment of relocation costs will be required before the Company will commence the work, except, at the sole discretion of the Company, under special circumstances.

10.8 RECOVERY FOR PROPERTY DAMAGE. If Company equipment is damaged through the negligence or intentional act(s) of any individual(s) or entity(s), the one(s) responsible for causing the damage shall reimburse the Company for all aspects of the resulting damages. The reimbursement shall include costs related to: labor, material, transportation and tools. "Labor" shall include benefit and administrative overheads based on the Company's current standard schedule, including third party contract repairs or modifications. Additionally, "Labor" may be calculated using a "blended" or average pay rate consistent with the above referenced standards. "Materials" may include an added stores expense calculated using the above referenced standards.

RULES AND REGULATIONS - Continued

11. TARIFF OPTIONS ON APPLICATIONS FOR SERVICE

11.1 CHOICE OF RATE. Where the classes of service-supply or conditions of use are such that two or more rates are available, an applicant shall select the rate or rates to be applied to the applicant's service.

11.2 COMPANY ASSISTANCE. The Company upon request will, to a reasonable extent, assist an applicant in selecting the most advantageous rate or rate application.

11.3 RATE CHANGES. A Customer may not change rates during the "initial contract term" as defined in the "Definition of Terms and Explanation of Abbreviations" section above. At any other time, a Customer may change to a rate for which the Customer qualifies upon 30 days' notice to the Company. The new rate will be effective the next meter reading date after Company approval.

The Company will not make any rate change retroactive, unless the Company failed to adequately respond to a Customer's request for assistance or modification at the time of such request.

RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY

12.1 REGULARITY OF SUPPLY. The Company will use reasonable diligence to provide a continuous, regular and uninterrupted supply of service.

12.2 CURTAILMENT OF SERVICE.

a. Authority to Curtail. In the event of a natural gas emergency, the Company may curtail the availability of natural gas service to its Customers in accordance with this Rule 12.2.

b. Priority of Service. Following are the service priority categories listed in descending order of priority (highest to lowest):

Priority 1

(1) Residential and firm critical commercial essential human needs.

Priority 2

(2) Firm small commercial requirements, excluding critical essential human needs requirements in Category 1, and firm large commercial and industrial requirements for plant protection.

(3) Firm small industrial requirements.

(4) Firm large critical commercial and industrial requirements, excluding firm critical commercial essential human needs requirements in Category 1.

(5) Firm large non-critical commercial and industrial requirements other than requirements for boiler fuel use.

(6) Firm large non-critical commercial and industrial requirements for boiler fuel use.

Priority 3

(7) Contractually interruptible use.

c. Definitions Applicable. The definition for terms used in the Curtailment of Service Rule are as follows:

(1) Alternate Fuel Capability. The installed and operable ability to use any fuel other than natural gas on a time sensitive basis. For purposes of this definition, alternate fuel means any fuel other than natural gas or its equivalent.

(2) Commercial Use. Gas usage by Customers engaged primarily in the sale of goods or services including, but not limited to, consumption by office buildings, institutions and governmental agencies and shall include Customers in Standard Industrial Classification Codes 01 through 09, 15 through 19, and 49 through 99. Commercial use shall not include use of gas for manufacturing or electric power generation.

(3) Critical Use. Gas usage where natural gas, or its equivalent, is the only feasible form of energy due to its combustion characteristics, controllability or chemical properties.

(4) Essential Human Needs Use. Gas usage in any building where persons normally dwell, including residences, apartment houses, dormitories, hotels, hospitals, and nursing homes, where the Customer does not have alternate fuel capability.

(5) Firm Service. Natural gas service offered to Customers under tariffs or contracts that anticipate no interruption of natural gas service.

(6) Industrial Use. Gas usage by Customers engaged primarily in a process which creates or changes raw or unfinished materials into another form or product including the generation of electric power and shall include Customers in Standard Industrial Classification Codes 10 through 14 and 20 through 39.

(7) Interruptible Service. Natural gas services that can be temporarily discontinued under terms and conditions specified by tariff or contract.

RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY – Continued

(8) Large Customer. A customer with annual usage of at least 18,000 Mcf during the prior calendar year.

(9) Natural Gas Emergency. Whenever the aggregate demand of firm service customers on the Company's system or portion of the Company's system, for any reason, exceeds or threatens to exceed the gas supply or capacity that is actually and lawfully available to the Company to meet the demands, and the actual or threatened excess creates an immediate threat to the Company's system operating integrity or the ability of the Company to satisfy the demand requirements of its Priority 1 Customers (including when continued delivery of gas to Customers would prevent the Company to arrange for the injection of gas into underground storage pools necessary for the protection of winter season supply requirements).

(10) Non-Critical Use. Gas usage where natural gas is not the only feasible form of energy; i.e., where the Customer has alternate fuel capability.

(11) Small Customer. A customer with annual usage of less than 18,000 Mcf during the prior calendar year.

(12) System Maintenance Order ("SMO") – as defined in the definitions section of the tariff.

(13) Plant Protection Use. Minimum usage of natural gas required to prevent physical harm to an industrial or commercial customer's facility, or danger to personnel at the facility, when the protection cannot be afforded through the use of an alternative fuel. Plant protection requirements includes usage necessary for the protection of the material in process as would otherwise be destroyed, but does not include deliveries required to maintain production.

(14) Residential Use. Gas usage in a residential dwelling or unit for space heating, air conditioning, cooking, water heating, or other domestic purposes.

d. Curtailment Process.

(1) Reservation of Company Right to Curtail. The Company reserves the right to reduce or eliminate the availability of firm natural gas service to Customers during a natural gas emergency, on a system-wide or localized basis ("curtailment"), when, in the Company's sole judgment, curtailment of natural gas service is necessary to protect the integrity of service to Priority 1 customers and/or the Company's gas distribution system assets. When necessary, the Company may curtail service to Priority 1 customers.

(2) Pre-Curtailment Procedures. To avoid curtailment of service, the Company will use reasonable business and operational efforts to interrupt all Priority 3 services; issue appropriate system maintenance orders (SMO) to HVT and LVT Customers, their Natural Gas Suppliers or other agents; and/or request customers to institute voluntary usage reductions.

(3) Curtailment Directive. In the event that Pre-Curtailment Procedures are not practicable or fail to protect the integrity of service to Priority 1 customers and/or the Company's gas distribution system assets, the Company may issue a curtailment directive. The curtailment directive should be reasonably well-tailored by the Company to require Customers of lower priority services to reduce usage by an amount calculated by the Company, as necessary to minimize the potential threat to public health and safety and to minimize the effect of a natural gas emergency on the integrity of service to Priority 1 customers and/or the Company's gas distribution system assets but may be issued without regard to priorities of service. During the period specified by the curtailment directive, Customers directed to curtail usage must comply with the directive or face physical shut-off by the Company and/or the assessment of penalties elsewhere set forth in this Rule 12.

RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY – Continued

(4) Curtailment Sequence. Curtailment of a customer class of a higher priority shall not be initiated until all Customers falling into the lower classifications have been completely curtailed. Where only partial curtailment of any one classification is required, customer usage should be reduced pro rata to the extent reasonably possible. As applied to High Volume Transportation Customers served under Rate TS-F, pro rata reductions will be based on a percentage of the Customer's Transportation Contract Quantity unless the Customer has alternative fuel capability.
If the Customer has alternative fuel capability, a pro rata reduction shall be based on a percentage of the Customer's Transportation Contract Quantity less the daily alternative fuel capability. The Company shall restore service as soon as practicable to any gas-fired generation facility that is deemed critical to electric system reliability by the applicable electrical system's control area operator.

(5) Customer Notification. The Company shall provide maximum notice possible of a curtailment directive or of a change in curtailment amount or priority level set forth in a curtailment directive. In the curtailment directive, the Company shall specify the authorized consumption for a specified period or until further notice. The Company reserves the right to provide notice by any reasonable means, including by telephone, pager, e-mail, facsimile or personal contact. If such notice is by telephone, then it will be followed by a written notice to the Customer, specifying the Customer's curtailment percentage and resulting peak day, daily, monthly, seasonal or annual authorized entitlement, as the case may be. An emergency curtailment may be made after oral notice to the Customer, effective when so given, but such oral notice will be confirmed in writing within 48 hours.

(6) Commission Notification. The Company shall notify the Commission as soon as practicable after the issuance of a curtailment directive.

(7) Curtailment Directive Exceeding 5 Days. The Company must obtain Commission authorization before it may extend a curtailment directive beyond a maximum duration of 5 business days. Business days shall be all days except Saturdays, Sundays, and federal holidays.

(8) Natural Gas Emergency Plan. This Rule 12 is supplemented by Company procedures referenced in the Company's Natural Gas Emergency Plan filed by the Company in compliance with Commission Regulations, 52 Pa. Code § 59.63 and 59.71 et seq., and such procedures may be modified from time to time.

e. Unauthorized Use.

(1) Penalties. A Customer determined to have used natural gas in violation of a SMO issued pursuant to Rule 12.2.d(3) or a curtailment directive issued by the Company ("unauthorized use") shall pay the Company a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. Also, included will be the actual, additional cost incurred by the Company as a result of such unauthorized gas usage, as reasonably determined by the Company.

The term "market rate" shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-Non NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

(2) Disposition of Penalties. As of December 31, of each year, the Company shall subtract the total of all penalties paid that year to the Company's suppliers from penalties collected that year from Customers. The Company will then distribute all remaining penalties collected by the Company to its curtailed Customers who did not incur penalties under e(i) above.

(3) To determine the amount of reimbursement due a Customer, the total amount to be redistributed shall be divided by the total volume of sales during the twelve-month period to all Customers eligible for reimbursement. This quotient shall represent the factor, which when multiplied by an eligible Customer's total purchase volume during the twelve-month period will equal the amount to be credited to that Customer. However, no reimbursement shall be made to Customers who have terminated service during the year.

(4) The Company will make periodic reports to the Commission containing itemized statements, status of penalty accounts and the extent and nature of disbursements from such accounts made during that period.

RULES AND REGULATIONS – Continued

12. SERVICE CONTINUITY - Continued

12.3 LIMITATION OF LIABILITY. Should the supply of service be curtailed or interrupted by the Company because of gas shortage, or for the purpose of making repairs, changes or improvements, in any part of its system for the general good of the service or the safety of the public, or should the supply of service be interrupted, curtailed or fail, by reason of accident, weather, strike, legal process, state or municipal interference, or any cause whatsoever the Company shall not be liable for damages, direct or consequential, resulting from such interruption or failure unless such interruption or failure resulted from the Company's wanton or willful misconduct. If the supply of service to a firm service Customer is interrupted for more than seven consecutive days as a result of the Company's wanton or willful misconduct, the Customer's bill will be prorated for the month during which this interruption occurs.

In all other circumstances, including but not limited to failure to furnish a sufficient supply of gas or failure to transport the customer's gas to the customer, the liability of the Company to customers or other persons for damages, direct or consequential, including damage to equipment and appliances, loss of business, or loss of production caused by any interruption or variation in supply or pressure, or any other failure in the supply of natural gas shall in no event, unless caused by the willful and/or wanton misconduct of the Company, exceed an amount in liquidated damages equivalent to the greater of $1000 or two times the charge to the customer for the service affected during the period in which such interruption or variation in supply or pressure, or any other failure in the supply of natural gas occurs.

The Company makes no warranty as to merchantability or fitness for a particular purpose, express or implied, by operation of law or otherwise. To the extent applicable under the Uniform Commercial Code or on any theory of contract or products liability, the Company limits its liability in accordance with the previous paragraph to any Customer or third party for claims involving and including, but not limited to, strict products liability, breach of contract, and breach of actual or implied warranties of merchantability or fitness for an intended purpose.

12.4 ADDITIONAL LIMITATIONS OF LIABILITY IN CONNECTION WITH CUSTOMER CHOICE. Other than its duty to deliver natural gas, the Company shall have no other duty or liability to a Customer receiving Competitive Natural Gas Supply arising out of or relating to a contract or other relationship between such Customer and an NGS. The Company shall implement Low Volume Customer selection of an NGS consistent with applicable rules of the Commission and shall have no liability to a Low Volume Customer receiving Competitive Natural Gas Supply arising out of or relating to switching NGSs unless the Company is negligent in switching or failing to switch a Customer. The Company shall have no duty or liability with respect to natural gas before it is delivered by an NGS to a point of delivery on the Company's distribution system. After its receipt of natural gas at the point of delivery the Company shall have the same duty and liability for distribution service to Customers receiving Competitive Natural Gas Supply as to those purchasing natural gas from the Company.

12.5 NOTICE OF TROUBLE. The Customer must immediately notify the Company if there is any defect, leak, trouble or accident affecting the supply of gas.

RULES AND REGULATIONS - Continued

13. CUSTOMER'S USE OF SERVICE

13.1 RESALE OF SERVICE. As of January 5, 1980, the resale of gas and/or service provided by the Company is prohibited for Customers who receive gas service from the Company through a master meter and resell it to individual dwelling units by the use of submeters. Customers receiving service prior to January 5, 1980, may resell gas purchased from the Company through a single master meter in accordance with 66 Pa.C.S. § 1313 if the purchased gas is: (1) for the total requirements of the premises served and (2) the use of the resold gas conforms to the availability requirements of this tariff for the Customer's own account.

13.2 FLUCTUATIONS. Gas and/or service must not be used in such a manner as to cause unusual fluctuations or disturbances in the Company's supply system, and, in the case of violation of this rule, the Company may discontinue service, or require the Customer to modify the installation and/or equip it with approved controlling devices.

13.3 ADDITIONAL LOAD. Any additional loads, either connected to existing equipment or new equipment, will not be allowed except by consent of the Company.

13.4 FAILURE TO GIVE NOTICE. Failure to give notice of additions or changes in load or location shall render the Customer liable for any damage to the regulator, meters, or other equipment of the Company, caused by the additional or changed installation.

14. MEASUREMENT

14.1 SUPPLY OF METERS. The measurement of gas usage shall be by meters furnished and installed by the Company. The Company will select the type and make of metering equipment, and may, from time to time, change or alter the equipment, its sole obligation being to supply meters that will accurately and adequately furnish records for billing purposes.

14.2 SPECIAL MEASUREMENTS. The Company shall have the right, at its option and its own expense, to place demand meters, pressure gauges, special meters, or other instruments, on the premises of any Customer for the purpose of determining the adequacy of the Company's service or for making tests of all or any part of the Customer's load.

14.3 METER READING INTERVALS. The Company will read its meters at scheduled regular intervals of one or more months and will render standard bills for the recorded gas usage based upon the time interval between meter readings. Only those bills which cover a period of service of less than 27 days or more than 34 days will be prorated.

14.4 ESTIMATED USAGE. The Company may estimate the amount of gas usage at the premises where access to the meter is not available, or to installations at remote locations, for such number of months as the type of installation, normal regularity of usage, or other circumstances may warrant, and will render bills in standard form based on such estimate and so marked, for the Customer's acceptance. Meter readings will be secured from time to time and billing will be revised when they disclose that the estimate failed to approximate the actual usage. For residential Customers, an actual meter reading will be obtained at least every six months, in accordance with Commission regulations.

14.5 CORRECTION TO STANDARD CONDITIONS. The quantities of gas used may be corrected to standard conditions, namely 60 degrees Fahrenheit temperature and 30 inches of mercury barometric pressure. All methods employed in correcting measurements of gas volume to said standard conditions shall be in accordance with established industry standards.

14.6 TELEMETRY AND TELEPHONE EQUIPMENT

(a) Customer shall permit PECO to install and operate telemetering equipment to remotely read PECO’s meter.

(b) Customer shall provide and pay for telephone service required for the operation of PECO’s equipment and/or the transmittal of data from PECO’s meter, as directed by PECO. Customer must maintain either a dedicated non-digital telephone line or telephone equipment that converts the digital signal to analog. Customer shall provide telephone service for this purpose at least fifteen (15) working days prior to the commencement of service under this agreement.

(c) Service will not be provided prior to the date on which Customer installs the required telephone service. Customer is responsible to maintain the telephone service in working order at all times.

(d) PECO will read the meter on the last day of the month if a reading is not transmitted. If PECO determines that the phone line is not functioning, Customer will be notified that the phone line must be repaired within thirty (30) days.

(e) If more than thirty (30) days elapse and the telephone service is not restored to working order to PECO’s satisfaction, then the following steps will be taken:

(1) If PECO has sufficient capacity in its gas supply system to supply Customer, then Customer's Account will be served as firm service on PECO's Rate GC-General Service–Commercial and Industrial, for a minimum of twelve (12) months.

(2) If PECO does not have sufficient capacity in its gas supply system to supply Customer, then PECO will disconnect Customer's facility from the PECO gas supply system for a minimum of twelve (12) months. During any such period of disconnection, Customer will use an alternate fuel to meet its heating and process needs.

RULES AND REGULATIONS - Continued

15. TESTS

15.1 METER TESTS. The Company, at its expense, will make periodic tests and inspections of its meters in order to maintain them at a high standard of accuracy. See 52 Pa. Code § 59.21.

15.2 REQUEST TESTS. The Company will make additional tests or inspections of its meters at the request of a Customer, or an NGS providing Competitive Natural Gas Supply to a Customer, but reserves the right to charge the Customer or NGS, as applicable, any Commission-approved charge as provided in the Commission's Gas Regulations.

15.3 ADJUSTMENT FOR ERROR. Should any meter become defective or fail to register correctly, the quantity of gas consumed shall be determined by a test of the meter, or by the registration of a meter set in its place during the period next following, or by averaging the amount of gas used for the nearest meter reading period preceding and the meter reading period immediately following the date when the meter was found not be to registering, taking into consideration the character of use by the Customer.

15.4 RESIDENTIAL METER ERRORS. Meter errors in residential service may be determined on the basis of the registration of the corresponding period during the preceding year, if records are available and conditions of use remain the same.

15.5 ADMINISTRATION TESTS. The Company, at its own expense, will make only such tests as it deems necessary for the proper administration of its rates, or as are required by law.

15.6 TESTING SERVICE. The Company will, upon request by the Customer, make tests to supply special information regarding the Customer's use of service, provided that the estimated cost of such special tests shall be paid by the Customer to the Company at the Company's discretion.

16. PAYMENT TERMS

16.1 BILLING PERIOD. Billing for service will be based upon the amount of use and the time interval of its supply. Rate values stated for direct application to monthly periods will be adjusted when the time elapsed between readings is substantially greater or less than a month.

16.2 BILLING OPTIONS. A Low Volume Customer may select one of the following two billing options as communicated to PECO by the customers' supplier: (1) Consolidated NGDC Billing; or (2) Separate NGS Billing.

16.3 PAYMENT PERIOD. Bills are payable upon presentation, and payment may be made at any authorized payment agency. Payment for service received must be made on or before the due date shown on the bill, which shall be not less than 20 days from the date of transmittal of the bill for Rate GR, GC and OL (excluding Summary Billing Accounts); not less than 15 days from the date of transmittal of the bill for all other rates, including Summary Billing Accounts, with the exception of accounts (including Summary Billing Accounts) with the United States of America or the Commonwealth of Pennsylvania or any of their departments or institutions for which 30 days will be allowed. If a normal due date should fall on a Saturday, Sunday, bank holiday, or any other day when the offices of the Company which regularly receive payments are not operating, the due date shall be extended to the next business day. The payment period will not be extended because of the Customer's failure to receive a bill unless said failure is due to the fault of the Company.

16.4 FINANCE CHARGE. If payment may be made at an authorized payment agency after the due date shown on the bill, a finance charge will be added to the unpaid balance until the entire bill is paid. If payment is made by mail, the finance charge will be added if the payment is received by the Company more than 5 days after the due date shown on the bill. For Rates GR, GC and OL, this finance charge will be 1-1/2% per month; for all other rates the finance charge will be 2% per month.

16.5 BUDGET BILLING

(a) At the option of a Customer receiving service under Rates GR, GC, and OL, an estimated total bill for all service to be received by the Customer over a twelve-month period may be budgeted over the period and an average bill rendered monthly for payment each month. Any difference between the budgeted amounts so paid and the actual charges for a twelve-month budget period will at the customer's option, either be amortized over the next twelve months or incorporated into the twelfth month bill. Absent an indication of preference from the customer, the debit or credit will be amortized. Budget billing may be discontinued upon the customer's request at which time any difference between budget billing amounts and actual charges becomes due and payable. If a monthly budget bill is not paid, a late fee will be added to the unpaid balance of actual charges on the next billing date in accordance with Rule 16.4. Any such late fee will be calculated based on the lesser of budget billing arrears and arrears from actual charges.

(b) When the Company provides Consolidated NGDC Billing, the NGSs charges will be included in the Customer's Budget Billing Plan.

16.6 CALCULATION OF FINANCE CHARGE. Where a finance charge is applicable, the amount of the finance charge to be added to the unpaid balance shall be calculated by multiplying the unpaid past due balance, exclusive of any previous unpaid finance charges, by the appropriate finance charge rate. Finance charges shall be applied to all charges when the Company is providing Supplier of Last Resort service and to the Fixed Distribution Service Charges, Variable Distribution Service Charges and any applicable service charges when the Customer has selected an NGS. The Company will apply finance charges to NGS charges at the NGS's electronic request when the Company is performing billing services for the NGS.

16.7 APPLICATION OF PAYMENT. When the Company provides Consolidated NGDC Billing or SLR (Sales) Service and a Low Volume Customer remits a partial payment to the Company, the payment will be applied as follows:

1. Any past due balances including those for prior PECO basic service charges, for prior NGS receivables purchased by the Company, for prior installment amounts on payment agreements, and also for any reconnection charges.
2. Any current charges including those for PECO basic service charges, for current NGS receivables purchased by the Company, and for current installment amounts on payment agreements.
3. Non-basic service charges.

16.8 RETURNED CHECK CHARGE. If a check received in payment of a Customer's account is returned to the Company unpaid by the Customer's bank and cannot be redeposited by the Company for payment on the second attempt, a $20.00 charge for the returned check will be added to the Customer's account.

16.9 BILLING ERRORS. When the Company provides Consolidated NGDC Billing, the Company shall not be responsible for billing errors resulting from incorrect information received from an NGS.

16.10 PAYMENT TERMS. The Company will negotiate payment arrangements with Sales Service Customers The Company will also negotiate payment arrangements for customers served under Consolidated NDGC Billing which includes NGS charges. If the NGS is providing Separate NGS Billing (“dual billing”), the Company will not negotiate agreements on behalf of those NGS charges.

RULES AND REGULATIONS - Continued

17. TERMINATION BY THE COMPANY

17.1 NON-PAYMENT SHUT-OFF. On reasonable notice, the Customer is subject to collection action, including termination of service (in accordance with the Pennsylvania Public Utility Code or the Commission's regulations,) on the portion of the past due amount attributable to the Company's charges for service and/or gas commodity. Upon termination of service, the Company may also remove its equipment. Notice that complies with applicable Commission regulations shall conclusively be considered "reasonable hereunder". Consistent with 52 PA Code §56.100, the Company will accept the following most current and valid documents as proof of household income: (1) income tax returns; (2) pay stubs; (3) benefit letters and governmental agency verification; (4) other forms to be accepted at the Company's discretion. The customer must provide this information within 10 days of the Company's request. This information may also be used by the company to determine deposit requirements, payment arrangements, and any other income specific program.

17.2 SHUT-OFF FOR CAUSE. The Company may terminate on reasonable notice if entry to its meter or meters is refused or if access thereto is obstructed or hazardous; or if utility service is taken without the knowledge or approval of the Company; or for other violation of these Rules and/or applicable Commission rules in accordance with the Pennsylvania Public Utility Code or the Commission's regulations.

17.3 SAFETY SHUT-OFF. The Company may terminate without notice if the Customer's installation has become hazardous or defective.

17.4 DEFECTIVE EQUIPMENT SHUT-OFF. The Company may terminate without notice if the Customer's equipment or use thereof might injuriously affect the equipment of the Company, or the Company's service to other Customers.

17.5 SHUT-OFF FOR FRAUD. The Company may terminate without notice for abuse, fraud, material misrepresentation of the customer's identity or tampering with the connections, meters, or other equipment of the Company.

17.6 RECONNECTION CHARGE. If service is terminated or discontinued by reason or act of the Customer, the same Customer, whether an applicant or a customer as defined at 66 Pa. C.S. § 1403, shall pay a reconnection charge, prior to restoration of service at the same address within twelve months after discontinuance or termination. The reconnection charges, listed below, are based on the Company's current standard schedule of reconnection fees, which include direct labor costs, contractor costs, and material/transportation costs.

	Reconnect Fees For Non-Payment
Gas Reconnect at Meter	$80.00
Gas Reconnect at Curb	$70.00

17.7 THEFT INVESTIGATION CHARGE. If the Company establishes that there has been confirmed active theft resulting from tampering with the Company meter on the customer's premises, and the customer is or was a customer as defined at Pa. C.S. § 1403 the customer shall pay a theft investigation charge in addition to any amount that the Company establishes is due for service used, but not registered on the Company's meter. The Company reserves the right to assess theft investigation charges as a precedent to reconnection of service as well as the right to assess a separate reconnection charge as described in Rule 17.6.

	Theft Investigation Fees
Gas Theft at Meter	$400.00

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18. UNFULFILLED CONTRACTS

18.1 NOTICE OF DISCONTINUANCE BY CUSTOMER. Notice to discontinue service prior to the expiration of a contract term will not relieve a Customer from any minimum, or guaranteed, payment under any contract or rate.

18.2 COMPLETION OF TERM. If, by reason of any act, neglect or default of a Customer, the Company's service is suspended, or the Company is prevented from supplying service in accordance with the terms of any contract it may have entered into with the Customer, the minimum charge for the unexpired portion of the contract term shall become due and payable immediately as liquidated damages in lieu of the anticipated returns from the said contract. These liquidated damages may, at the option of the Company, be offset by any estimated revenues from a succeeding Customer at the same location if such exists.

18.3 TEMPORARY SUSPENSION OF SERVICE. A residential or commercial Customer may elect to have service temporarily disconnected at the start of a period of suspension and then reconnected at the end of the period by paying a charge of $115.00. During the period of suspension, the Customer will be relieved of the payment of minimum bills.

RULES AND REGULATIONS - Continued

19. CANCELLATION BY CUSTOMER

19.1 TERMINATION NOTICE. Customers who have fulfilled their initial contract term and wish to discontinue service must give at least 7 days' notice to that effect, unless otherwise provided for in a rate schedule or service agreement.

19.2 FINAL BILL. The Customer is liable for service taken after notice to terminate the contract until the meter is read and gas shut off. The final bill for service is then due and payable within 20 days from the date of transmittal of the bill for residential customers and 15 days for non-residential customers.

19.3 EXIT FEES. A Customer, other than a Low Volume Customer, taking firm sales service that transfers to an interruptible service or to firm Transportation Service without firm standby sales service will be required to continue payment of the firm gas supply demand costs allocable to Customer's firm sales service until the Company is able to reduce its contract demand level or otherwise utilize the contract demand allocable to Customer's firm sales service.

20. GENERAL

20.1 OFFICE OF THE COMPANY. Wherever, in this Tariff, it is provided that notice be given or sent to the Company, or the office of the Company, such notice, delivered or mailed, postage prepaid, to any commercial office, shall be deemed sufficient, unless the Main Office of the Company at 2301 Market Street, Philadelphia, is expressly mentioned.

20.2 NO PREJUDICE OF RIGHTS. The failure by the Company to enforce any of the terms of this Tariff shall not be deemed a waiver of its right to do so.

20.3 GRATUITIES TO EMPLOYEES. The Company's employees are strictly forbidden to demand or accept any personal compensation, or gifts, for service rendered by them while working for the Company on the Company's time.

20.4 BILLING CHANGES. Where billing changes are made as the result of an investigation made at Customer's request or by routine inspection, the change of billing may be applied to the bill for the regular meter reading period preceding such investigation, and will in any event apply to the bill for the period during which the check is made.

20.5 EXCEPTIONAL CASES. Sales and/or Transportation service shall be subject to the provisions of this Tariff; but where special conditions or problems arise for which provision is not otherwise made, the Company may modify or adapt its terms to meet the peculiar requirements of such case, provided that such modified terms are a rational expansion of standard tariff provisions.

20.6 ASSIGNMENT. Subject to the Rules and Regulations, all contracts made by the Company shall be binding upon, and oblige and ensure to the benefit of, the successors and assigns, heirs, executors, and administrators of the parties thereto.

20.7 OTHER CHARGES. Except as where otherwise provided in this tariff the Company may where feasible, provide and charge for services requested by the Customer or his agent. The Company is not obligated to provide such services. The Company will, if possible, give the Customer an advance written estimate of the costs to provide the service.

21. GAS CHOICE PROGRAM ENROLLMENT AND SWITCHING

In accordance with all applicable final Commission Orders:

21.1 All LVT Customers will be eligible to obtain Competitive Natural Gas Supply starting with their first regularly scheduled meter reading after July 1, 2000.

21.2 The Company will send Gas Choice Release of Information packets to all new LVT Customers, which information will provide Customers the opportunity to authorize the release of their confidential account information. PECO annually notifies customers that they can change this authorization. Every three years, in accordance with PUC Docket No. M-2012-2324075, PECO will re-solicit its entire customer base for the purpose of opting out of disclosing information.

21.3 Customers may select a Supplier, as often as monthly, in accordance with Commission Orders and the procedures contained in this Tariff and in the Supplier Coordination Tariff.

21.4 If a Customer, or agent authorized to act on the Customer's behalf, contacts the Company via telephone to select a Supplier, the Company will advise the Customer or agent to contact the selected Supplier to submit the required electronic enrollment file.

21.5 For a Customer's enrollment to become effective on the Customer's next regularly scheduled meter read date, the Supplier must submit the required electronic file at least eleven (11) days prior to said meter read date.

21.6 If, in any month, a Customer selects more than one Supplier, the Supplier that submitted to the Company, before the end of the applicable Supplier selection period, the Supplier enrollment file with the latest valid Supplier contract will become the Customer's Supplier of record.

21.7 The Company will send a confirmation notice to all Customers who have made a Supplier selection by the next business day after receiving the Customer's enrollment file from the Supplier. This confirmation shall include notification of a five (5) day waiting period in which the Customer may cancel its selection of a Supplier. The waiting period shall begin on the date the Company confirmation is mailed to the Customer. If the five (5)-day waiting period expires, and the Customer has not contacted the Company to cancel the Supplier selection, the Supplier will become the Customer's Supplier of record.

21.8 If the Customer elects to cancel its Supplier selection, the Company will notify the rejected Supplier electronically via an approved EDI transaction. In the event the Customer cancels its Supplier selection after the five (5) day waiting period, the Customer will be required to remain with the selected Supplier for a minimum of one billing cycle.

21.9 If at least eleven (11) days prior to the Customer's next regularly scheduled meter read date, a Customer contacts the Company to request a switch from a Supplier to the Company's (SLR) Sales Service, the request will be effective as of that meter read date and the Company as the supplier of-last resort will become the Supplier of record for delivery.

21.10 In the event the Customer requests a switch less than eleven (11) days before the Customer's next regularly scheduled meter read date, the switch will be effective as of the next following meter read date.

21.11 If, other than at the end of a billing cycle, and because of an NGS's default, an NGS terminates sales to a Customer prior to the end of the Customer's contract with the NGS, for gas supply provided through the end of the relevant billing cycle, said Customer will pay the NGS's contract rate in accordance with information filed by the NGS with the Commission.

22. USAGE DATA

At the request of the Customer, or at the request the Customer's designated Supplier or authorized agent, the Company will supply twelve (12) individual months of historical usage data for no charge. Any additional historical information requested will be provided, if available, for a fee of ninety-two dollars ($92.00) per provision.

23. AFFILIATED MARKETER STANDARDS OF CONDUCT

PECO Energy and its affiliated natural gas supplier shall comply with the following requirements:

(1) A natural gas distribution company shall apply its tariffs in a nondiscriminatory manner to its affiliated natural gas supplier and any nonaffiliated natural gas supplier.

(2) A natural gas distribution company shall not apply a tariff provision in any manner that would give its affiliated natural gas supplier an unreasonable preference over other natural gas suppliers with regard to matters such as scheduling, balancing, transportation, storage, curtailment, capacity release and assignment, or non-delivery, and all other services provided to its affiliated natural gas supplier.

(3) Mandatory tariff provisions shall not be waived by a natural gas distribution company for any natural gas suppliers absent prior approval of the Commission.

(4) If a tariff provision is not mandatory or provides for waivers, a natural gas distribution company shall grant the waivers without preference to its affiliated natural gas supplier or non-affiliated natural gas supplier.

(5) A natural gas distribution company shall maintain a chronological log of tariff provisions for which it has granted waivers. Entries shall include the name of the party receiving the waiver, the date and time of the request, the specific tariff provision waived and the reason for the waiver. The chronological log shall be open for public inspection during normal business hours.

(6) A natural gas distribution company shall process requests for distribution services promptly and in a nondiscriminatory fashion with respect to other requests received in the same or a similar period. A natural gas distribution company shall maintain a chronological log showing the processing of requests for transportation services. The chronological log shall be open for public inspection during normal business hours.

(7) If a natural gas distribution company provides a distribution service discount, fee waiver or rebate to its favored customers, or to the favored customers of its affiliated natural gas supplier, the natural gas distribution company shall offer the same distribution service discount, fee waiver or rebate to other similarly situated customers. Offers shall not be tied to any unrelated service, incentive or offer on behalf of either the natural gas distribution company or its affiliated natural gas supplier. A chronological log shall be maintained showing the date, party, time and rationale for the action. The chronological log shall be open for public inspection during normal business hours.

(8) Subject to customer privacy or confidentiality constraints, a natural gas distribution company shall not disclose, directly or indirectly, any customer proprietary information to its affiliated natural gas supplier unless authorized by the customer. To the extent that a natural gas distribution company does disclose customer information without customer authorization, it shall contemporaneously provide this same information to other similarly situated natural gas suppliers in a similar fashion so as not to selectively disclose, delay disclosure, or give itself or its affiliated natural gas supplier any advantage related to the disclosure. A chronological log shall be maintained showing the date, time and rationale for the disclosure. The chronological log shall be open for public inspection during normal business hours.

(9) A natural gas distribution company shall justly and reasonably allocate to its affiliated natural gas supplier the costs or expenses for general administration or support services provided to its affiliated natural gas supplier.

(10) Natural gas distribution companies shall not condition or tie the provision of any product, service or price agreement by the natural gas distribution company (including release of interstate pipeline capacity) to the provision of any product or service by its affiliated natural gas supplier.

(11) A natural gas distribution company shall not give its affiliated natural gas supplier preference over a non-affiliated natural gas supplier in the provision of goods and services including processing requests for information, complaints and responses to service interruptions. Natural gas distribution companies shall provide comparable treatment in its provision of such goods and services without regard to a customer’s chosen natural gas supplier.

(12) A natural gas distribution company and its affiliated natural gas supplier shall maintain separate books and records. Further, transactions between the natural gas distribution company and its affiliated natural gas supplier shall not involve cross-subsidies. Any shared facilities shall be fully and transparently allocated between the natural gas distribution company function and the affiliated natural gas supplier function. The natural gas distribution company accounts and records shall be maintained such that the costs incurred on behalf of an affiliated natural gas supplier may be clearly identified.

(13) Natural gas distribution company employees who have responsibility for operating the distribution system, including natural gas delivery or billing and metering, shall not be shared with an affiliated natural gas supplier, and their offices shall be physically separated from the office(s) used by those working for the affiliated natural gas supplier. Such natural gas distribution company employees may transfer to an affiliated natural gas supplier provided such transfer is not used as a means to circumvent these interim standards of conduct.

(14) Neither the natural gas distribution company nor its affiliated natural gas supplier shall directly or by implication, falsely and unfairly represent to any customer, natural gas supplier or third party that an advantage may accrue to any party through use of the natural gas distribution company's affiliates or subsidiary, such as:

- That the Commission regulated services provided by the natural gas distribution company are of a superior quality when services is purchased from its affiliated natural gas supplier; or
- That the merchant services (for natural gas) are being provided by the natural gas distribution company when they are in fact being provided by an affiliated natural gas supplier;
- That the natural gas purchased from a non-affiliated natural gas supplier may not be reliably delivered;
- That natural gas must be purchased from an affiliated natural gas supplier to receive Commission regulated services.

(15) When affiliated natural gas supplier market or communicate to the public using the natural gas distribution company name or logo, it shall include a legible disclaimer that states:

- That the affiliated natural gas supplier is not the same company as the natural gas distribution company;
- That the prices of the affiliated natural gas supplier are not regulated by the Pa PUC; and
- That a customer does not have to buy natural gas or other products from the affiliated natural gas supplier in order to receive the same quality service from the natural gas distribution company.

When an affiliated natural gas supplier advertises or communicates verbally through radio or television to the public using the natural gas distribution company name or logo, the affiliated natural gas supplier shall include at the conclusion of any such communication a legible disclaimer that includes all of the disclaimers listed in this paragraph.

(16) Except in competitive bid situations a natural gas distribution company shall not (a) jointly market or jointly package its Commission regulated services with the services of an affiliated natural gas supplier or (b) offer or provide to its affiliated natural gas supplier products or services, including bill inserts in its natural gas distribution company bills promoting an affiliated natural gas supplier's services or a link from the natural gas distribution company's web-site, unless the natural gas distribution company offers or provides the products or service to all non-affiliated natural gas supplier on the same terms and conditions.

(17) A natural gas distribution company shall not offer or sell natural gas commodity or capacity to its affiliated natural gas supplier without simultaneously posting the offering electronically on a source generally available to the market or otherwise

making a sufficient offer to the market. The natural gas distribution company shall maintain a chronological log of these public disseminations. The chronological log shall be open for public inspection during normal business hours.

(18) Natural gas distribution companies shall establish and file with the Commission a complaint procedure for dealing with any alleged violations of any of the standards of conduct, with the exception of paragraph (9), which are exclusively under the purview of the Commission. These procedures shall be developed in consultation with interested parties during consideration of any tariff guided by this section and §69.191 (relating to general). The Commission may grant an exception to these requirements if warranted by the facts or circumstances.

(19) A natural gas distribution company shall keep a chronological log of any complaints, excepting paragraph (9), regarding discriminatory treatment of natural gas suppliers. This chronological log shall include the date and nature of the complaint and the resolution of the complaint. The chronological log shall be open for inspection during normal business hours.

(20) Dispute Resolution Procedures: In addition to the procedure set forth in paragraph 18:

- Any dispute between a natural gas supplier, and/or an affiliated natural gas supplier, and a non-affiliated natural gas supplier alleging a violation of any of these Standards of Conduct provisions, the natural gas supplier must provide the natural gas distribution company and/or affiliated natural gas supplier, as applicable, a written Notice of Dispute that includes the names of the Parties and Customer(s), if any, involved and a brief description of the matters in dispute.

- Within five (5) days of a natural gas distribution company's and/or affiliated natural gas supplier's receipt of a Notice of Dispute, a designated senior representative of each of the Parties shall attempt to resolve the dispute on an informal basis.

- In the event the designated representatives are unable to resolve the dispute by mutual agreement within thirty (30) days of said referral, the dispute shall be referred for mediation through the Commission's Office of Administrative Law Judge. A party may request mediation prior to that time if it appears that informal resolution is not productive.

- If mediation is not successful, then the matter shall be converted to a formal proceeding before a Commission Administrative Law Judge.

- Any Party may file a complaint concerning the dispute with the Commission under relevant provisions of the Public Utility Code.

- Parties alleging violations of these standards may pursue their allegations through the Commission's established complaint procedures. A complainant bears the burden of proof consistent with 66 Pa. C.S. §332 (relating to Public Utility Code) in regard to the allegations and may impose penalties for such violations pursuant to 66 Pa.C.S.§ 3301.

(21) A natural gas distribution company shall file a compliance filing within sixty (60) days of the entry of an order approving or modifying a restructuring plan, which sets forth a detailed plan for compliance with this Standard of Conduct as well as the Commission separation and cost allocation requirements already ordered.

(22) Every natural gas distribution company and its affiliated natural gas supplier shall formally adopt and implement these provisions as company policy and shall take appropriate steps to train and instruct its employees in their content and application.

RULES AND REGULATIONS – Continued

24 REQUESTS FOR ENERGY EFFICIENCY INFORMATION

Upon request of a Customer for energy efficiency information, the Company will provide a copy of its then current residential or commercial energy efficiency guide, as applicable.

25. CREDITWORTHINESS OF A NATURAL GAS SUPPLIER (NGS) SERVING HIGH VOLUME TRANSPORTATION CUSTOMERS

(a) Unless a mutual agreement is reached between the Company and a NGS, or other applicable entity as specified in 52 Pa. Code § 62.101 the amount and form of security shall be based on the criteria established in 52 Pa. Code §62.111. In accordance with §62.111, a NGS seeking to deliver natural gas supplies to the Company for the account of one or more of the Company's non-exempt HVT Customers must satisfy at least one of the following financial criteria:

(1) The NGS has a minimum credit rating of 3A2 from Dun & Bradstreet, a minimum bond rating of Baa2 from Moody's, or a rating of BBB from Standard & Poor's, Fitch ICBA or Duff & Phelps; or

(2) The NGS has furnished the Company with an irrevocable and binding form of security (e.g., surety bond, letter of credit, security interest in collateral acceptable to the Company, a corporate guaranty, or a written affirmation of financial support by a parent or affiliated company) issued by an obligor that has a minimum credit rating of 3A2 from Dun & Bradstreet, a minimum bond rating of Baa2 from Moody's, a minimum bond rating of BBB from Standard & Poor's, Fitch ICBA or Duff & Phelps, or, for an insurance company, an A.M. Best credit rating of no less than A-and in which the obligor designates the Company as the sole beneficiary and which otherwise is in a form and amount acceptable to the Company; or

(3) The NGS provides the Company with a cash deposit and/or a cash escrow arrangement in an amount and form acceptable to the Company, and agrees, in a writing furnished to the Company, to be responsible, as between the Company and the Supplier, for the payment of all deficient and excess delivery charges assessed in accordance with the Company's Gas Transportation Service – General Terms and Conditions that are caused by the NGS' excess or deficient deliveries. Such responsibility on the part of the NGS would not relieve the HVT Customer of its responsibility for the payment of the same charges in accordance with the Gas Transportation General Terms and Conditions. If the NGS is determined to have been responsible for the excess/deficient delivery and if the NGS pays the related charges to the Company, then the HVT customer would be relieved of such responsibility.

For the purposes of this subsection (a), the "amount acceptable to the Company" shall be a dollar amount ($US) equal to the monetary value obtained by multiplying 45 days of average daily winter usage for each HVT Customer supplied by the NGS times the then effective Commodity Charge.

(4) The NGS has furnished the Company with an acceptable amount of Security in the form of an escrow account or nets any gas supply sales that the NGS has made to the Company and for which the Company owes payment to the NGS against the amount of Security required. The amount of Security contained in either situation must be in an amount equal to the monetary value obtained by multiplying 45 days of average daily winter usage for each HVT Customer supplied by the NGS times the then effective Commodity Charge.

RULES AND REGULATIONS – Continued

(b) The Company shall have the right to assess each NGS' creditworthiness on an annual basis. As such, the Supplier is required to furnish annual audited financial statements to the Company. In the event the Company does not receive any annual audited financial statements, unaudited financial statements may be acceptable. The Company also may perform more than one financial analysis for any Supplier during the course of the year when the Company reviews financial information of a Supplier and determines, in the Company's judgment that the Supplier's creditworthiness has materially changed.

(c) Unless a mutual agreement is reached, the amount of Security required may be modified based on one or more of the following criteria:

1. The NGS's past operating history on all other NGDC systems, including the duration that the NGS operated on each system, the number of customers served on each system and any supply reliability problems that occurred on each system.
2. An NGS's credit reports.
3. The number and class of customers being served.
4. Information that materially affects a NGS's creditworthiness such as:

a) a change in the NGS's recent operating history on the Company's system or on other NGDC systems that has materially affected NGDC system operation or reliability. Such a change may occur when a Supplier fails to deliver natural gas supply to meet its customers' needs or fails to comply with NGDC operational flow orders as defined at 52 Pa. Code § 69.11;

b) a change in the NGS's credit reports that materially affects its creditworthiness. Creditworthiness could be materially affected when 2 of the following credit rating companies change the Supplier's credit rating:
1. Dun & Bradstreet
2. Standard & Poor's Rating Services Inc.
3. Transunion LLC
4. Equifax Inc.
5. Experian Information Solutions, Inc;

c) a significant change, defined as a 25% change over a 30-day period, in the number and class of customers served, the volume of gas delivered or the average unit price of natural gas;

d) a change in operational or financial circumstances that materially affects a NGS's creditworthiness. This can occur when 2 of the following investment rating companies change the NGS's rating of its issued securities from an investment grade or good rating to a speculative or moderate credit risk rating and vice versa:
1. Standard & Poor's Rating Services Inc.
2. Moody's Investment Service, Inc.
3. Fitch, Inc.
4. A.M. Best Company, Inc.
5. DBRS, Inc.;

e) a change in the NGS's demonstrated capability to provide the necessary volume of natural gas to meet its customers' needs that materially affects the Company's system operation or reliability. Such a change may occur when the NGS fails to deliver natural gas supply sufficient to meet its customers' needs on 5 separate occasions within a 30-day period or fails to comply with the Company's operational flow orders.

RULES AND REGULATIONS – Continued

5. The NGS's demonstrated capability to provide the volume of natural gas necessary to meet its customers' needs.

(d) After it is reasonably determined by the Company that an adjustment to the amount of Security provided by the Supplier is required, the Company will adjust the Security amount in accordance with subsection (a)(3).

(e) The NGS shall have the affirmative obligation to inform the Company in writing of any material change in its financial condition in a timely manner.

(f) Notwithstanding anything to the contrary stated in this Rule 25, an NGS shall not be creditworthy if, for any reason, it owes a past due amount to the Company that is not subject to a good faith billing dispute and the payment has not been received by the Company within two business days after the Company has provided a past due notice, or if so determined by order of the Pennsylvania Public Utility Commission.

(g) When the Company determines that a Security adjustment is required, it will provide written notice to the NGS. The NGS shall comply with the Company's determination within 5 business days after the NGS is served with such notice. If the NGS disagrees with the Company's determination, it shall file a dispute in accordance with subsection (h). However, the NGS is still required to post the full amount of adjusted Security requested by the Company within 5 business days after the NGS is served with the Company's notice.
An NGS also may request, in writing, that the Company adjust its Security amount according to the criteria set forth in subsection (c). The Company will provide a written response to the NGS within 5 business days after receipt of the written request from the NGS. In the event that the Company agrees with the NGS's request, the NGS shall post the Security adjustment within 5 business days after the NGS is served with the Company's determination. In the event that the NGS disagrees with the Company's determination, it may file a dispute in accordance with subsection (h). However, if the Company requires an adjustment of Security, the NGS is still required to post the full amount of adjusted Security within 5 business days after the NGS is served with the Company's notice.

(h) An applicant, licensee or NGS shall notify the Company in writing of any dispute(s) it may have regarding the form and amount of Security or the adjustment of Security requested by the Company. If a resolution cannot be reached within 30 days after the Company receives the written notice, the applicant, licensee or NGS may do any of the following:

1. Request that the Secretary of the PUC initiate an informal mediation and resolution process. If the NGS is dissatisfied with the PUC's decision at the informal level, it may petition to appeal the decision or file a Formal Complaint.
2. File a Formal Complaint at the Commission.
3. File a Petition challenging the criteria used by the Company to determine the form and amount of Security requested or the Security adjustment amount.

If a NGS initiates a dispute or files a complaint related to an adjustment in Security by the Company, the following requirements exist during the pendency of the dispute:

1. The NGS is required to provide and maintain the full adjusted Security amount to the Company until the dispute is resolved.
2. The NGS must continue to operate in accordance with the Company's system operations and business rules and practices.
3. The NGS must continue to deliver natural gas volumes necessary to fulfill customer needs and provide customer support services.
4. The Company shall allow the NGS to continue to operate on the Company's system.

RULES AND REGULATIONS – Continued

26. GAS QUALITY STANDARDS: Quality of Gas Delivered to the Company

A. Terms Defined. The following definitions shall apply throughout the Gas Quality Standards sections of this Tariff.

Biogas is a mixture of naturally produced gases resulting from the decomposition of organic matter under anaerobic conditions (in an oxygen-free environment). The principal constituents are methane and carbon dioxide.

Interconnect or interconnection is the physical connection between the Company's natural gas system and the physical equipment of another natural gas system associated with the interconnection point, which may include the interconnection metering, pressure control, filtration and odorization equipment.

Renewable Natural Gas (RNG) is a term used to describe Biogas that has been upgraded for use in place of fossil natural gas. The Biogas used to produce RNG may come from a variety of sources, including municipal solid waste landfills, digesters at water resource recovery facilities (wastewater treatment plants), livestock farms, food production facilities, and organic waste management operations.

RNG Counterparty is any individual, entity, Customer, or otherwise-described party that executes a Renewable Natural Gas agreement with the Company for purposes of injecting, transporting, using, or otherwise introducing or causing RNG to be introduced into the Company's natural gas system. This definition includes RNG producers and/or production facilities.

B. Quality of Gas at Point(s) of Receipt with an Interstate Pipeline.

Natural gas delivered by or caused to be delivered on behalf of Customer to the Company at point(s) of receipt with an interstate pipeline shall conform to the quality specifications of the pipeline(s) used to transport natural gas.

C. For Quality of Gas at Point(s) of Receipt for Renewable Natural Gas.

Gas Quality Standards are specifications meant to ensure that the RNG entering the Company's natural gas system will be interchangeable with the natural gas that the Company currently distributes and will not damage the Company's or the Company's customers' equipment. RNG being injected into the Company's natural gas system shall conform to the following quality specifications at the time of receipt at the interconnection point. With advance notice from RNG Counterparty in writing, the Company may allow deviations from these standards on a case-by-case basis at its sole discretion. With notice to RNG Counterparty in writing, the Company may require adherence to additional specifications, for good cause as determined by the Company on a case-by-case basis at its sole discretion.

C.1 General Specifications:

(a) The Company's interconnection equipment will have automatic and remote shut-off capabilities to ensure the following constituents and standards can be adequately monitored at the point of interconnection and the safety and reliability of the Company's natural gas system protected. The Company may temporarily discontinue the receipt of RNG without notice if it does not conform to the following specifications.

The following constituents and values will be monitored by the Company via chromatograph or other such measurement device as the Company may employ and will be monitored on a regular basis as the Company may determine from time to time (i.e., hourly):

(i) **Heating Value**: The following minimum and maximum heating values apply, both measured on a dry basis at a temperature of sixty degrees Fahrenheit (60^{O} F) and a pressure of 14.73 pounds per square inch absolute (PSIA)—the minimum heating value is 970 Btu (gross) per standard cubic foot (SCF) and the maximum heating value is 1070 Btu (gross) per SCF.

(ii) **Delivery Temperature**: The RNG delivery temperature is not to be below fifty degrees Fahrenheit (50^{O} F) or above one hundred and twenty degrees Fahrenheit (120^{O} F).

(iii) **Methane:** The gas shall contain a minimum of 95% Methane.

(iv) **Propane**: The gas shall contain a maximum of 20% Propane.

(v) **Hydrogen Sulfide:** The gas shall contain no more than 0.5 grains per 100 SCF.

(vi) **Total Sulfur**: The gas shall contain no more than 5 grains per 100 SCF total sulfur. This includes Carbonyl Sulfide (COS) and Carbon Disulfide (CS_2), hydrogen sulfide, mercaptans, and mono, di- and poly-sulfides.

(vii) **Carbon Dioxide and Nitrogen**: The gas shall contain no more than 2% by volume of carbon dioxide (CO_2), not more than 3% by volume of nitrogen (N_2), and shall contain no more than 5% by volume of combined nonhydrocarbon gases including, but not limited to, CO2, N2, and O_2.

(viii) **Hydrogen:** The gas shall contain no more than 0.1% by volume of hydrogen.

(ix) **Oxygen:** The gas shall not contain in excess of 0.3% by volume of oxygen, and the parties agree to exercise every reasonable effort to keep the gas completely free of oxygen.

RULES AND REGULATIONS – Continued

(x) **Hydrocarbons:** The RNG hydrocarbon dew point is not to exceed forty-five degrees Fahrenheit (45^{O} F) at the delivery pressure.

(xi) **Water Vapor:** The gas shall not contain in excess seven (7) pounds (lbs.) of water vapor/1mcf.

C.2 RNG Constituents:

(a) RNG Counterparty shall complete laboratory testing, as described in Section C.3, for the trace constituents listed in the following table. If testing results do not meet the standards listed in the table below, the Company may temporarily interrupt RNG service as outlined in Section C.4.

Parameter	**Symbol**	**Level (max unless noted otherwise)**	**Units**
Siloxanes	Si	5	Mg Si/m³
Hydrogen	H_2	0.1	% vol
Ammonia	NH_3	0.00%	Mol%
Mercury	Hg	0.08	mg/m³
Arsenic	As	0.19	mg/m³
Copper	Cu	0.6	mg/m³
Oxygen	O_2	0.3	% vol
Propane	C_3H_8	20	% vol
Nitrogen	N_2	3	% vol
Methane	CH_4	95	% vol
Hydrogen Sulfide	H_2S	0.5	Grains per 100 SCF
Carbon Dioxide	CO_2	2	% vol
Carbon Monoxide	CO	0.1	% vol
Volatile Organic Compounds	VOCs	5	PPM
Moisture or Water Content	H_2O	7	Pounds per million cu ft
Total Sulfur	S	5	Grains per 100 SCF

(b) Additional Quality Requirements:

(i) **Wobbe Index**: The RNG shall have a minimum Wobbe Number of 1255 Btu/ft^3 and shall not have a maximum Wobbe Number greater than 1375 Btu/ft^3.

(ii) **Dust, Gums, etc.**: The gas shall be free of objectionable odors, dust, gum, dirt, impurities and other solid or liquid or hazardous matter which might interfere with proper operation of the facilities, lines, regulators, meters or other appliances through which it flows. Filters shall be installed on the RNG Counterparty's equipment (i.e., the supply side) to catch any debris.

RULES AND REGULATIONS – Continued

(iii) **Bacteria:** The gas and any associated liquids shall not contain any active bacteria or bacterial agent capable of contributing to or causing operational problems.

C.3 Testing Requirements:

(a) To ensure adherence to the Gas Quality Standards, testing required under this section will be performed by RNG Counterparty using independent, certified third-party laboratories. The Company shall be notified at least five (5) calendar days in advance of the RNG sampling and tests and have the option to observe the samples being taken. Test results will be shared with the Company within five (5) calendar days of the test results being received by RNG Counterparty. Unless otherwise noted herein, the costs associated with the required testing shall be paid by RNG Counterparty.

In its discretion, the Company may, at its own cost and expense, collect samples for testing at the utility meter at the point of interconnection. Re-testing shall be allowed to verify and validate the results of any test. The cost of retesting shall be paid by the entity requesting the retest.

(b) **RNG Pre-Interconnection Testing:** Prior to the injection of RNG into the Company's natural gas system, RNG Counterparty shall conduct two (2) tests over a two (2)-to four (4)-week period for the Gas Quality Standards. If during pre-injection testing, the RNG is found to be non-compliant with the Gas Quality Standards, RNG Counterparty shall make necessary modifications to reduce constituent levels and restart pre-interconnection testing. Connection to the Company's natural gas system is subject to successfully passing these two (2) tests.

(i) **RNG Periodic Testing:** The Company will require RNG Counterparty to conduct periodic testing for the Gas Quality Standards on a quarterly basis (at least once in every three-month period).

C.4 Temporary Discontinuance of Gas Receipt:

(a) **Temporary Discontinuance:** The Company reserves the right to temporarily discontinue the receipt of gas on an immediate basis whenever the RNG is non-compliant with any of the specifications as detailed in the Gas Quality Standards and, as applicable, an RNG agreement, whenever there is an imminent safety risk (including any risk stemming from either Company or RNG Counterparty-owned facilities or equipment), or whenever Company reasonably determines it is necessary to maintain system integrity.

(i) The Company may temporarily disconnect RNG equipment from the Company's natural gas system in the event of an emergency condition as determined by the Company, for scheduled maintenance, construction or repair, or if it is reasonably determined to be necessary in order to maintain the safety and reliability of its system.

(ii) The Company shall notify RNG Counterparty promptly when it becomes aware of an emergency condition or any other condition that that may reasonably be expected to affect RNG Counterparty's operation of its RNG production facility. RNG Counterparty shall notify the Company promptly when it becomes aware of an emergency condition or any other condition that may reasonably be expected to affect the Company's natural gas system. To the extent information is known, the notification shall describe the emergency condition, the extent of the damage or deficiency, the expected effect on the operation of both parties' facilities and operations, its anticipated duration, and the necessary corrective action.

(iii) In the event the Company temporarily discontinues the receipt of RNG for any reason, RNG Counterparty is responsible for ceasing production or diverting RNG from the point of interconnection, as applicable.

(iv) The Company and the RNG Counterparty shall provide five (5) business days' notice prior to temporarily interrupting service for scheduled maintenance, construction, or repair. The Company shall use reasonable efforts to coordinate such temporary disconnection with RNG Counterparty.

(v) The Company and RNG Counterparty shall cooperate with each other to restore any production facility, interconnection facilities, and the Company's natural gas system to their normal operating state as soon as reasonably practicable following any disconnection pursuant to this section, as long as the safety and reliability of the Company's natural gas system is ensured, including ensuring that all Gas Quality Standards are met. During a temporary discontinuance of service, RNG Counterparty shall still be charged the Customer Charge.

(vi) The Company shall not be liable, under any circumstances or in any respect, to RNG Counterparties or any other person or entity for damages arising either directly or indirectly from temporary discontinuance of service.

(b) **Restart Procedures:**
(i) To restart RNG injection following a temporary discontinuance, RNG Counterparty will complete a minimum of one (1) test of the RNG in accordance with the testing requirements specified above. Injection may then resume if the test indicates the RNG complies with the Gas Quality Standards. This test must be reviewed and approved by both the Company and RNG Counterparty.

(ii) To restart RNG injection following a shut-off resulting from above concerns, RNG Counterparty shall notify the Company and may begin injections only once the Company has given approval.

(iii) When the Company's crews are required on-site to restart the RNG injection, including but not limited to on-site testing, the Company has the right to require the associated RNG Counterparty to bear all costs required for such activities, including but not limited to materials, transportation, labor, and overhead.

(iv) The Company and RNG Counterparty may agree to modify the restart procedures identified in this Section on a case-by-case basis, upon written agreement between each party.

C.5 Changes Impacting Gas Quality:

The Company must be notified as soon as possible of any substantive expected change to the feedstock, raw gas quality or conversion process that has the potential to impact RNG quality, so that the Company can review whether any action is required including, but not limited to, additional testing, new or revised Gas Quality Standards or a suspension of the receipt of RNG into the Company's natural gas system.

STATE TAX ADJUSTMENT CLAUSE

In addition to the net charges provided for in this Tariff, **a value of 0.03%** will apply to all service on and after January 1, 2026.

Whenever any of the tax rates used in the calculation of the surcharge are changed, the surcharge will be recomputed as prescribed by the Commission. The recalculation will be submitted to the Commission within ten days after the tax rates change occurs and the effective date shall be ten days after filing.

In addition, if a recalculation is submitted as a result of a tax rate change, the Company will thereafter file each year on December 21 annual updates with the Commission which will reflect only this tax change. These annual updates will be effective ten days after filing and will continue until such as the effect of the change in tax rates has been included in base rate.

PROVISIONS FOR RECOVERY OF UNIVERSAL SERVICE FUND CHARGE (USFC)

Variable Distribution Service Charge rates for gas service in Residential Rate Schedule GR of this Tariff shall include a **credit** of $0.0043 per Mcf (1,000 cubic feet) for recovery of Universal Service Fund Cost (USFC), calculated in the manner set forth below. The USFC rate for gas service shall be increased or decreased annually, to reflect changes in the level of Universal Service Fund costs, net of base rate recoveries, in the manner described below:

COMPUTATION OF USFC.

The USFC per Mcf ($x.xxxx), shall be computed in accordance with the formula set forth below:

$$\textbf{USFC} = \frac{(C-E-I)}{(S)}$$

The USFC, so computed, shall be included in distribution rates charged to Customers for service pursuant to the rate schedule identified above. The amount of USFC, per Mcf, will vary, if appropriate, based upon annual filings by the Company.

In computing the USFC, per Mcf, pursuant to the formula above, the following definitions shall apply:

"Reconcilable Customer Assistance Program (CAP) Costs" – The difference between (A) the sum of discounts provided to CAP customers (CAP revenue shortfalls) and forgiven Pre-Program Arrearages recovered through base rates, and; (B) the sum of actual total CAP discounts and actual forgiven Pre-Program Arrearages, net of an offset factor applied on a monthly basis as follows:

1. PECO will compare the actual month-end CAP participation level to the baseline CAP participation level most recently approved by the Commission within a Company distribution rate case proceeding to determine the CAP participation above or below the baseline for that month. (The Company's current baseline CAP participation level is 27,372 participants, approved under Docket Number R-2026-3060860.)
2. PECO will calculate the actual average CAP discount per customer for that month, dividing the actual amount of discounts by the actual month-end CAP participation level.
3. PECO will multiply the results of Items 1 and 2 above together to obtain the portion of the offset basis related to CAP discounts above or below the approved baseline.
4. PECO will compare the actual month-end Pre-Program Arrearage forgiven to one-twelfth of the baseline Pre-Program Arrearage level most recently approved by the Commission within a Company distribution rate case proceeding to determine the Pre-Program Arrearage forgiven above or below the baseline for that month. (The Company's current baseline Pre-Program Arrearage Forgiveness level is $1,254,870, approved under Docket Number R-2026-3060860.) The result will be the portion of the offset basis related to Pre-Program Arrearage forgiveness.
5. PECO will calculate the monthly offset by applying the offset factor percentage most recently approved by the Commission within a Company distribution rate case proceeding to the sum of Items 3 and 4 above. (The Company's current offset factor percentage is 11.9%, approved under Docket Number R-2026-3060860.)

USFC – Universal Service Fund Charge determined to the nearest one-hundredth cent (0.01¢) to be included in the rate for each Mcf of Variable Distribution Service Charge calculated under Rate Schedule GR, to recover or refund Reconcilable CAP Costs and other items as addressed in the "E" factor.

C - Cost in dollars of the Reconcilable CAP Costs for the projected period.

E - the net (overcollection) or undercollection of Universal Service Fund Charges. The net overcollection or undercollection shall be determined for the most recent period, beginning with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. Included in the "E" factor will be Reconcilable CAP Costs, and up to $1,400,000 of LIURP expenditures above the $2.25 million threshold included in base rates. Also included in the "E" Factor will be any rate credit due customers to the extent PECO expends less than $3,500,000 annually in its Energy Efficiency Plan effective January 1, 2027. Included in the E factor calculation is the reconciliation of Pre-Program Arrearages, effective January 1, 2027.

Each overcollection or undercollection statement shall also provide for refund or recovery of amounts necessary to adjust for overrecovery or underrecovery of "E" factor amounts under the previous USFC.

I – Interest shall be computed monthly at a 6% annual simple interest rate from the month that the overcollection or undercollection occurs to the mid-point of the period such overcollection is refunded or undercollection is recouped. The interest calculation will not apply to the LIURP amounts.
"

S - projected Mcf of gas service to be billed under Rate GR (exclusive of CAP Rider) during the projected period when rates will be in effect. Mcf's shall be consistent with the projected residential throughput used in the applicable Purchased Gas Cost filing.

FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECONCILIATION.

The Company's annual USFC filing and its annual reconciliation statement shall be submitted to the Commission 120 days prior to new rates being effective December 1 of each year, or at such time as the Commission may prescribe. The USFC mechanism is subject to annual audit review by the Bureau of Audits.

SALES SERVICE COSTS (SSC) - Section 1307(f)

PROVISIONS FOR RECOVERY OF GAS COSTS RELATED TO SALES SERVICE

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Commodity Charge (CC) at **$$6.3478** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, **$6.3263** per Mcf for Rate Schedules GC and **$6.3087** per Mcf for Rate Schedules OL, L and MV-F for recovery of gas costs related to Sales Service, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code as well as procurement costs as reflected in the Gas Procurement Charge ("GPC") and uncollectable charge-offs as reflected in the Merchant Function Charge ("MFC"). In addition, the Gas Cost Adjustment Charge (GCA) in the amount of **$0.4023** per Mcf will be applicable to customers served under the above mentioned Rate Schedules. Such rates for Sales Service gas shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of gas costs related to Sales Service.

COMPUTATION OF CC AND GCA PER MCF.

The CC and GCA, per Mcf, shall be computed to the nearest one-hundredth cent (0.01¢) in accordance with the formulas set forth below:

$$CC = \frac{(C)}{(S)} \times \frac{1}{(1 - T)} + GPC + MFC \quad ; \text{and}$$

$$GCA = \frac{(E)}{(S)} \times \frac{1}{(1 - T)}$$

For March 1, June 1 and September 1 quarterly updates, CC is revised to:

$$CC = \left(CC1 + \frac{O}{S1} + \frac{C1)}{S2}\right) \times \frac{1}{(1-T)} + GPC + MFC$$

The CC and GCA so computed, shall be applicable to Customers receiving Sales Service pursuant to the rate schedules identified above. The CC and GCA, per Mcf, will vary, if appropriate, based upon annual filings by the Company pursuant to Section 1307(f) of the Public Utility Code and such supplemental filings as may be required or be appropriate under Section 1307(f) or the Commission's regulations adopted pursuant thereto.

In computing the Charges, per Mcf, pursuant to the formulas above, the following definitions shall apply:

"CC" - Purchased Gas Costs determined to the nearest one-hundredth cent (0.01¢) to be charged for each Mcf of-Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

"C" - Cost in dollars: (a) for all types of purchased gas, project the commodity and all non-storage interstate pipeline costs for each purchase (adjusted for net current gas stored) for the projected period when rates will be in effect; plus (b) the cost of gas provided from storage and LNG facilities, less (c) the new monthly cash-out result determined pursuant to Rule 10.11.3, or the successor thereto, of the Gas Choice Supplier Coordination Tariff .

"C1" - defined as the difference between the current projection of "C" and the projection of "C" used to establish the rates effective December 1 for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"CC1" – defined as the Commodity Charge rate effective December 1 of the current PGC period.

"O" – defined as the difference between the current net over/under collections and the associated projected net over/under collections from the applicable PGC rate calculation, as defined by Commodity Charge revenues less associated gas costs, from December 1 of the current PGC year through the end of the month before the applicable quarterly rate change.

GCA - the "E" factor component of the CC, representing the net overcollection or undercollection of Purchased Gas Costs. Applicable to Sales Service and determined to the nearest one-hundredth cent (0.01¢) for service provided under Rate Schedules GR, GC, CAP, OL, L, and MV-F of this Tariff.

"E" - the net (overcollection) or undercollection of Purchased Gas Costs applicable to the CC.

The net overcollection or undercollection shall be determined for the most recent period permitted under law, which shall begin with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. The annual filing date shall be the date specified by the Commission for the Company's Section 1307(f) tariff filing.

Supplier refunds received after July 1, 2001 associated with Commodity Charges will be included in the calculation of "E" with interest added at the annual rate of six percent (6%) beginning with the month such refund is received by the Company.

"GPC" – Gas Procurement Charge determined to the nearest one-hundredth cent (0.01¢) to be charged for each Mcf of Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L, and MV-F of this Tariff.

"MFC" – Merchant Function Charge determined to the nearest one hundredth cent (0.01¢) to be charged for each Mcf of Sales Services gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

Each overcollection or undercollection statement shall also provide for refund or recovery of amounts necessary to adjust for overrecovery or underrecovery of "E" factor amounts under the previous 1307(f) GCA.

Interest shall be computed monthly at the prime rate for commercial borrowing in effect sixty days prior to the tariff filing in accordance with Section 1307(f) of the Public Utility Code as modified by PA Act 47. The interest rate will be based on that reported in the Wall Street Journal. Interest will be computed from the month that the overcollection or undercollection occurs to the effective month such overcollection is refunded or undercollection is recouped. The interest rate basis will become effective with the December 2016 billing cycle

"S" projected Mcf of gas to be billed to Customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L & and MV-F during the projected period when rates will be in effect.

"S1" - defined as the applicable twelve month mcf sales billed to customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L, and MV-F.

"S2" – defined as mcf sales billed to customers receiving Sales Service under Rate Schedules GR, GC, CAP, OL, L, and MV-F and for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"T" the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

"Purchased Gas Costs" - Include the direct costs paid by the Company for the purchase and delivery of natural gas (which also includes liquefied natural gas, synthetic natural gas, and natural gas substitutes, excluding propane, the cost of which is included in the Balancing Service Costs) to its system to supply its Customers (plus such portion of the Company's used and unaccounted for gas as the Commission permits), including costs paid under agreements to purchase natural gas from sellers; costs paid for transporting natural gas to its system; all charges, fees, taxes and rates paid in connection with such purchases, pipeline gathering, and transportation; and costs paid for employing futures, options and other risk management tools.

QUARTERLY UPDATES

The Company's rates for recovery of gas costs related to Sales Service are also subject to quarterly adjustments under procedures set forth in Section 1307 (f) of the Public Utility Code and in the Commission's regulations. Such updates shall reflect, adjustments for under or overcollections and, adjustments to the projected cost of gas related to Sales Service based upon more current versions of the same sources of data and using the same methods to project the gas costs related to Sales Service approved by the Commission in the Company's most recent annual proceeding for recovery of gas costs related to Sales Service under section 1307 (f).

OFF-SYSTEM SALES SHARING MECHANISM

The rate for Sales Service gas as determined above shall be adjusted to reflect the operation of the off-system sales sharing mechanism set forth herein. Revenues received by PECO Energy from third party storage management services and revenues from exchanges or swaps of gas, excluding the Customer's share of such revenue attributable to use or management of storage or related storage transportation capacity by customers not connected to the Company's system (which revenue shall be included in the Balancing Service Costs E factor, shall be included as off-system sales revenues). Effective April 1, 2001 through March 30, 2008 PECO Energy will be permitted to retain 25% of off system sales margin revenues up to the first $3.5 million in margin revenues, and PECO Energy will be permitted to retain 30% of off system sales margin revenues for margin revenues over $3.5 million. Subsequently, effective March 31, 2008 through November 30, 2028 and thereafter, until terminated or otherwise revised by Final Order of the Commission, PECO Energy will be permitted to retain 25% of off-system sales margin revenues. PECO Energy's share shall be computed on a pre-income tax basis, "below the line" for ratemaking purposes. The remaining off-system sales margin will be credited to the recovery of purchased gas costs. Margin revenues derived from sales of gas which is taken from system supply are defined as the unit revenue less the monthly weighted average commodity cost of gas, less any applicable taxes other than income taxes. Margin revenues derived from specific purchase sales (sales where a specific gas supply has been purchased to make a sale) shall be defined as the unit revenue less the specific purchase commodity cost of gas, less any applicable taxes other than income taxes. Specific purchase sales will have no impact on the cost of system supply. Off-system sales for operational purposes such as for meeting mandatory storage withdrawals are excluded from the mechanism. The calculations under this mechanism shall be subject to audit and to review in annual 1307(f) proceedings.

SALES SERVICE COSTS (SSC) - Section 1307 (f) - Continued

FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECTIFICATION.

The Company's annual Section 1307(f) filing or its annual reconciliation statement shall be submitted to the Commission by June 1 of each year, or such other time as the Commission may prescribe by order or by regulation.

The Company shall notify the Commission of any change in the price of purchased gas from any supplier, which change would cause an increase or decrease of more than one per cent (1%) in the "C" factor, defined above. Such notification will be given within thirty (30) days after the effective date of such change in price, or as soon as reasonably practical thereafter.

GAS PROCUREMENT CHARGE

PROVISIONS FOR RECOVERY OF GAS PROCUREMENT CHARGES

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall include the Gas Procurement Charge (“GPC”) at **$0.0452** per Mcf (1,000 cubic feet) for recovery of gas procurement costs related to Sales Service, calculated in the manner set forth below and pursuant to the Final Orders at Docket No. P-2012-2328614 and Docket No. R-2026-3060860.
The GPC will be included in the Company’s Commodity Charge (“CC”) and the Price to Compare (“PTC”).

COMPUTATION OF GAS PROCUREMENT CHARGE

The GPC shall include gas procurement costs incurred by the Company on behalf of its Sales Service customers. The GPC shall include the following costs:

1. Natural gas supply service, acquisition and management costs, including natural gas supply bidding, contracting, hedging, credit, risk management costs and working capital.
2. Administrative, legal, regulatory and general expenses related to those natural gas procurement activities, excluding those related to the administration of firm storage and transportation capacity.

The GPC shall be computed as follows:

GPC = GPCC/S x 1/(1-T)

“GPCC” – applicable gas procurement costs as defined in Items 1 and 2 above.

“S” – defined as twelve months of Mcf sales billed to customers receiving Sales Service under Rate Schedules GR CAP, GC, OL, L, and MV-F.

“T” – the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

The costs for the GPC shall remain in effect until reviewed and updated in each base rate case filed by the Company. The calculation of the GPC shall be updated in conjunction with updates in costs for the GPC. The GPC shall not be subject to reconciliation for any prior period over or under collections.

MERCHANT FUNCTION CHARGE

PROVISIONS FOR RECOVERY OF MERCHANT FUNCTION CHARGES

Rates for all Sales Service gas supplied under Rate Schedules GR, CAP GC, OL, L and MV-F shall include the Merchant Function Charge (“MFC”) at **$0.0404** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, at **$0.0189** per Mcf for Rate Schedule GC and at **$0.0013** per Mcf for Rate Schedules OL, L and MV-F for recovery of gas uncollectible charge-offs related to Sales Service, calculated in the manner set forth below and pursuant to the Final Order at Docket No. P-2012-2328614 and at Docket No. R-2026-3060860. The MFC will be included in the Company’s Commodity Charge (“CC”) and the Price to Compare (“PTC”) and shall be updated quarterly in conjunction with the calculation of the CC.

COMPUTATION OF MERCHANT FUNCTION CHARGE

The MFC shall include uncollectible charge-offs incurred by the Company on behalf of its Sales Service customers and calculated for Rate Schedules GR, CAP, GC, OL, L and MV-F. The MFC shall be computed as follows:

MFC = Write-Off Factor x CCEMFC x 1 / (1 – T)

“Write-Off Factor” - the write-off factors for Rate Schedules GR and CAP **(0.64%),** Rate Schedule GC **(0.30%)** and Rate Schedules OL, L and MV-F (**0.02%)** as determined at Docket No R-2026-3060860, the Company’s 2026 gas base rate case. The write-off factors shall be updated as part of future base rate cases.

“CCEMFC” – the applicable quarterly CC including the GPC and excluding the MFC.

“T” – the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

The calculation of the MFC shall be updated in conjunction with changes in the CC including the GPC and excluding the MFC and updates in the write-off factors. The MFC shall not be subject to reconciliation for any prior period over or under collections.

PRICE TO COMPARE

The Price to Compare (“PTC”) is comprised of the Commodity Charge (“CC”), the Gas Cost Adjustment (“GCA”), the Gas Procurement Charge (“GPC”) and the Merchant Function Charge (“MFC). The Commodity Charge includes the Gas Procurement Charge and the Merchant Function Charge. The PTC will change whenever any components of the PTC change. The current PTC’s are detailed below:

COMPONENT	RATES GR and CAP
Commodity Charge excluding GPC and MFC	$6.2622 per Mcf
Gas Cost Adjustment	$0.4023 per Mcf
Gas Procurement Charge	$0.0452 per Mcf
Merchant Function Charge	$0.0404 per Mcf
Price to Compare	$6.7501 per Mcf

COMPONENT	RATES GC
Commodity Charge excluding GPC and MFC	$6.2622 per Mcf
Gas Cost Adjustment	$0.4023 per Mcf
Gas Procurement Charge	$0.0452 per Mcf
Merchant Function Charge	$0.0189 per Mcf
Price to Compare	$6.7286 per Mcf

COMPONENT	RATES OL, L and MV-F
Commodity Charge excluding GPC and MFC	$6.2622 per Mcf
Gas Cost Adjustment	$0.4023 per Mcf
Gas Procurement Charge	$0.0452 per Mcf
Merchant Function Charge	$0.0013 per Mcf
Price to Compare	$6.7110 per Mcf

BALANCING SERVICE COSTS (BSC)- Section 1307(f)

PROVISIONS FOR RECOVERY OF BALANCING SERVICE COSTS.

Rates for Balancing Service for all gas delivered under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff shall be charged at **$0.3829** per Mcf (1,000 cubic feet) for recovery of those costs, calculated in the manner set forth below, pursuant to Section 1307(f) of the Public Utility Code. Such rates for Balancing Service shall be increased or decreased, from time to time, as provided by Section 1307(f) of the Public Utility Code and the Commission's regulations, to reflect changes in the level of recovery of Balancing Service Costs.

COMPUTATION OF BALANCING SERVICE COSTS PER MCF

Balancing Service Costs, per Mcf, shall be computed to the nearest one-hundredth cent (0.01¢) in accordance with the formula set forth below:

$$BSC = \frac{(C - E)}{(S)} \times \frac{1}{(1 - T)}$$

For March 1, June 1 and September 1 quarterly updates, the BSC is revised to:

$$BSC = \left(CC1 + \frac{O}{S1} + \frac{C1}{S2} - \frac{E}{S1}\right) \times \frac{1}{(1 - T)}$$

Projected Balancing Service Costs, so computed, shall be charged to Customers for all gas delivered pursuant to the rate schedules identified above. The amount of those costs, per Mcf, will vary, if appropriate, based upon annual filings by the Company pursuant to Section 1307(f) of the Public Utility Code and such supplemental filings as may be required or be appropriate under Section 1307(f) or the Commission's regulations adopted pursuant thereto.

In computing the Balancing Service Costs, per Mcf, pursuant to the formula above, the following definitions shall apply:

"BSC" - Balancing Service Costs determined to the nearest one-hundredth cent (0.01¢) to be charged to each Mcf of gas delivered under Rate Schedules GR, CAP, GC, OL, L and MV-F of this Tariff.

"C" - Cost in dollars: for all types of storage and related services, project the cost for the projected period when rates will be in effect.

"C1" - defined as the difference between the current projection of "C" and the projection of "C" used to establish the rates effective December 1 for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"CC1"- defined as the rate associated with "C" effective December 1 of the current PGC period.

"O" – defined as the difference between the current net over/under collections and the associated projected net over/under collections from the applicable PGC rate calculation, as defined by storage and related services revenues less associated storage and related services costs from December 1 of the current PGC year through the end of the month before the applicable quarterly rate change.

"E" - the net overcollection or undercollection of Balancing Service Costs.

The net overcollection or undercollection shall be determined for the most recent period permitted under law, which shall begin with the month following the last month which was included in the previous overcollection or undercollection calculation reflected in rates. The annual filing date shall be the date specified by the Commission for the Company's Section 1307(f) tariff filing.

Each overcollection or undercollection statement shall also provide for refund or recovery of amounts necessary to adjust for overrecovery or underrecovery of "E" factor amounts under the previous Balancing Service Costs Rate.

Interest shall be computed monthly at the prime rate for commercial borrowing in effect sixty days prior to the tariff filing in accordance with Section 1307(f) of the Public Utility Code as modified by PA Act 47. The interest rate will be based on that reported in the Wall Street Journal. Interest will be computed from the month that the overcollection or undercollection occurs to the effective month such overcollection is refunded or undercollection is recouped. The interest rate basis will become effective with the December 2016 billing cycle.

As otherwise described in the Sales Service Costs section "Off-System Sales Sharing Mechanisms", the portion of margin revenue attributable to certain balancing assets shall be included in the calculation of "E".

Supplier refunds received prior to July 1, 2001 will be included in the calculation of "E" with interest added at the annual rate of six per cent (6%) beginning with the month such refund is received by the Company.

"S" - projected Mcf of gas to be delivered to Customers during the projected period when rates will be in effect.

"S1" - defined as the applicable twelve months of mcf of gas to be delivered to customers.

"T" - the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

"S2" – defined as mcf sales delivered to customers for the period starting with the month of the effective date of the quarterly rate change through the end of the PGC period.

"T" - the portion of any applicable state gross receipts tax rate recovered through base rates, expressed as a decimal. The tax rate, if any, shall be the one in effect when the computation is made.

Balancing Service Costs - fixed and variable storage costs and the cost of propane to be charged to all customers served under Rate Schedules GR, CAP, GC, OL, L, and MV-F of this Tariff.

QUARTERLY UPDATES

The Company's rates for recovery of Balancing Service Costs are also subject to quarterly adjustments under procedures set forth in the Commission's regulations at 52.Pa. Code 53.64 (1) (5). Such updates shall reflect adjustments for under or over collections and adjustments to the projected cost of Balancing Services based upon more current versions of the same sources of data and using the same methods to project the Balancing Service Costs approved by the Commission in the Company's most annual proceeding for recovery of Balancing Service Costs under section 1307 (f) of the Public Utility Code.

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FILING WITH PENNSYLVANIA PUBLIC UTILITY COMMISSION; AUDIT; RECTIFICATION.

The Company's annual Section 1307(f) filing or its annual reconciliation statement shall be submitted to the Commission by June 1 of each year, or such other time as the Commission may prescribe by order or by regulation.

Consumer Education Charge (CEC)

PROVISIONS FOR RECOVERY OF CONSUMER EDUCATION COSTS

Purpose - The purpose of this surcharge is to provide for full and current cost recovery of expenditures associated with the Company's approved gas consumer education costs.

Applicability - The surcharge shall be charge calculated to the nearest one-hundredth cent (0.01¢), which shall be added to the Variable Distribution rates for all Low Volume Customers for recovery of Consumer Education Costs associated with Gas Choice. The rate shall be calculated separately for each customer class. The current Consumer Education Plan Cost for each Class 1 is $0.0013 per Mcf for Rates GR and CAP, Class 2 is $0.0000 per Mcf for Rate GC and for Class 3 is $0.0000 per Mcf for Rates L and MV-F.

COMPUTATION OF CEC
The CEC per MCF shall be calculated on an annual basis using the following formula:

$$CEC(n) = \frac{(C+E+I-H)}{S(n)}$$

In computing the CEC, pursuant to the formula above, the following definitions shall apply:

C – the cost of the consumer education program includes the following:

Consumer Education Cost: Costs attributable to the Company's payment of the Commission's Statewide Education Assessment and all incremental external and incremental internal costs of the Company's own local customer choice education program. Such program costs may include outreach programs, paid media, direct mail, company call center, grass roots outreach and other costs as approved by the Commission.

CEC(n) - consumer education costs for Low Volume Customers in rate class "n" including over/(under) recovery and associated interest.

E – The estimated over or (under) recovery from the prior year. The reconciliation period shall be the 12 months ended December 31.

I - Interest on any over or (under) recovery balance. Interest shall be a rate of 6% and shall be calculated from the month of over or under collection to the mid-point of the recovery period.

H – The value of revenue share commissions received by the Company for the customer class from a home services provider with which the Company has entered into a commercial arrangement for marketing of the home services provider's services to the Company's customers. Commissions will be allocated between the Company's Electric and Gas divisions in proportion to the customer counts in the customer class.

n – rate class where 1 = residential (Rate GR) 2 = small C&I (Rate GC) 3 = large C&I (Rate L).

S – projected MCF of gas, as included in the Balancing Service Costs (BSC) provided in the Company's most recent Commission approved annual 1307(f) Purchase Gas Cost (PGC) filing.

Filing Schedule:
The estimated surcharge shall be filed with the Commission by January 1 of each year to be effective on the following March 1. The application period shall be the 12 months that start the March 1 effective date of the surcharge. The CEC mechanism is subject to annual audit review by the Bureau of Audits.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC)

In addition to the net charges provided for in this Tariff, a charge of 0.00% will apply consistent with the Commission Order dated September 3, 2015 at Docket No. P-2013-2347340, approving the DSIC.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) (CONTINUED)

1. General Description

A. Purpose: To recover the reasonable and prudent costs incurred to repair, improve, or replace eligible property which is completed and placed in service and recorded in the individual accounts, as noted below, between base rate cases and to provide the Company with the resources to accelerate the replacement of aging infrastructure, to comply with evolving regulatory requirements and to develop and implement solutions to regional supply problems.

The costs of extending facilities to serve new customers are not included for recovery in the DSIC.

B. Eligible Property: The DSIC-eligible property will consist of the following:

Piping (account 376);
Couplings (account 376);
Gas services lines (account 380) and insulated and non-insulated fittings (account 378);
Valves (account 376);
Excess flow valves (account 376);
Risers (account 376);
Meter bars (account 382);
Meters (account 381);
Unreimbursed costs related to highway relocation projects where a natural gas distribution company or city natural gas distribution operation must relocate its facilities; and
Other related capitalized costs.

C. Effective Date: The DSIC will become effective October 1, 2015.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

2. Computation of the DSIC

A. Calculation: The initial DSIC, effective October 1, 2015, shall be calculated to recover the fixed costs of eligible plant additions that have not previously been reflected in the Company's rates or rate base and will have been placed in service between June 1, 2015 and August 31, 2015. Thereafter, the DSIC will be updated on a quarterly basis to reflect eligible plant additions placed in service during the three-month periods ending one month prior to the effective date of each DSIC update. Billing for the DSIC will be on a bills rendered basis. Thus, changes in the DSIC rate will occur as follows:

Effective Date of Change	Date to which DSIC Eligible Plant Additions Reflected
January 1	September - November
April 1	December - February
July 1	March - May
October 1	June - August

B. Determination of Fixed Costs: The fixed costs of eligible distribution system improvements projects will consist of depreciation and pre-tax return, calculated as follows:

1. Depreciation: The depreciation expense shall be calculated by applying the annual accrual rates employed in the Company's most recent base rate case for the plant accounts in which each retirement unit of DSIC-eligible property is recorded to the original cost of DSIC-eligible property.

2. Pre-tax return: The pre-tax return shall be calculated using the statutory state and federal income tax rates, the Company's actual capital structure and actual cost rates for long-term debt and preferred stock as of the last day for the three-month period ending one month prior to the effective date of the DSIC and subsequent updates. The cost of equity will be the equity return rate approved in the Company's last fully litigated base rate proceeding for which a final order was entered not more than two years prior to the effective date of the DSIC. If more than two years shall have elapsed between the entry of such a final order and the effective date of the DSIC, then the equity return rate used in the calculation will be the equity return rate calculated by the Commission in the most recent Quarterly Report on the Earnings of Jurisdictional Utilities released by the Commission.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

C. Application of DSIC: The DSIC will be expressed as a percentage carried to two decimal places and will be applied to the total amount billed to each customer for distribution service and the State Tax Adjustment Surcharge (STAS). To calculate the DSIC, one-fourth of the annual fixed costs associated with all property eligible for cost recovery under the DSIC will be divided by the Company's projected revenue for distribution service (including all applicable clauses and riders) for the quarterly period during which the charge will be collected, exclusive of the STAS.

D. Formula: The formula for calculation of the DSIC is as follows:

$$DSIC = \frac{(DSI * PTRR) + STFT + Dep + e) \times 1/(1-T)}{PQR}$$

Where:

DSI = Original cost of eligible distribution system improvement projects net of accrued depreciation and associated accumulated deferred income taxes pertaining to property-related book/tax depreciation timing differences resulting from the use of accelerated depreciation per Internal Revenue Code, 26 U.S. Code § 168.
.

PTRR = Pre-tax return rate applicable to DSIC eligible property.

STFT = (State Tax Flow Through) Pre-tax flow through calculated on book-tax timing differences between accelerated tax depreciation and book depreciation net of federal tax
[Note that a utility may elect to include STFT calculation in the PTRR component).

Dep = Depreciation expense related to DSIC-eligible property.

e = Amount calculated (+/-) under the annual reconciliation feature or Commission audit, as described below.

T= If applicable, Pennsylvania Gross Receipts Tax rate in effect during the billing month, expressed in decimal form.

PQR = Projected quarterly revenues for distribution service (including all applicable clauses and riders) from applicable customers.

Revenue shall be based on one-fourth of the projected annual revenues.

[NOTE: THE DSIC CALCULATION DOES NOT FACTOR IN THE PLANT OF ACQUIRED TROUBLED COMPANIES OR THE REVENUE OF CUSTOMERS ACQUIRED FROM TROUBLED COMPANIES UNTIL SUCH PLANT AND CUSTOMER RATES HAVE BEEN PART OF A BASE RATE CASE BY THE ACQUIRING UTILITY.]

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

3. Quarterly Updates. Supporting data for each quarterly update will be filed with the Commission and served upon the Commission's Bureau of Investigation and Enforcement, the Commission's Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the update.

4. Customer Safeguards

A. Cap: The DSIC is capped at 5.0% of the amount billed to customers for distribution service (including all applicable clauses and riders) as determined on an annualized basis.

B. Audit/Reconciliation: The DSIC is subject to audit at intervals determined by the Commission. Any cost determined by the Commission not to comply with any provision of 66 Pa C.S. §§ 1350, *et seq*., shall be credited to customer accounts. The DSIC is subject to annual reconciliation based on a reconciliation period consisting of the twelve months ending December 31 of each year, or the Company may elect to subject the DSIC to quarterly reconciliation but only upon request and approval by the Commission. The revenue received under the DSIC for the reconciliation period will be compared to the Company's eligible costs for that period. The difference between revenue and costs will be recouped or refunded, as appropriate, in accordance with Section 1307(e), over a one-year period commencing on April 1 of each year or in the next quarter if permitted by the Commission. If DSIC revenues exceed DSIC-eligible costs, such over-collections will be refunded with interest. Interest on over-collections and credits will be calculated at the residential mortgage lending specified by the Secretary of Banking in accordance with the Loan Interest and Protection Law (41 P.S. §§ 101, *et seq*.) and will be refunded in the same manner as an over-collection. The Company is not permitted to accrue interest on under collections

C. New Base Rates: The DSIC will be reset at zero upon application of new base rates to customer billings that provide for prospective recovery of the annual costs that had previously been recovered under the DSIC. Thereafter, only the fixed costs of new eligible plant additions that have not previously been reflected in the Company's rates or rate base will be reflected in the quarterly updates of the DSIC.

D. Customer Notice: Customers shall be notified of changes in the DSIC by including appropriate information on the first bill they receive following any change. An explanatory bill insert shall also be included with the first billing.

E. All customer classes: The DSIC shall be applied equally to all customer classes, except that the Company may reduce or eliminate the Rider DSIC to any customer with competitive alternatives who are paying flexed or discounted rates and customers having negotiated contracts with the Company, if it is reasonably necessary to do so.

DISTRIBUTION SYSTEM IMPROVEMENT CHARGE
(DSIC) (CONTINUED)

F. Earning Reports: The DSIC will also be reset at zero if, in any quarter, data filed with the Commission in the Company's then most recent Annual or Quarterly Earnings reports show that the Company would earn a rate of return that would exceed the allowable rate of return used to calculate its fixed costs under the DSIC as described in the pre-tax return section. The Company shall file a tariff supplement implementing the reset to zero due to overearning on one-day's notice and such supplement shall be filed simultaneously with the filing of the most recent Annual or Quarterly Earnings reports indicating that the Company has earned a rate of return that would exceed the allowable rate of return used to calculate its fixed costs

G. Residual E-Factor Recovery Upon Reset To Zero: The Company shall file with the Commission interim rate revisions to resolve the residual over/under collection or E-factor amount after the DSIC rate has been reset to zero.
The Company can collect or credit the residual over/under collection balance when the DSIC rate is reset to zero. The Company shall refund any overcollection to customers and is entitled to recover any undercollections as set forth in Section 4.B. Once the Company determines the specific amount of the residual over or under collection amount after the DSIC rate is reset to zero,the Company shall file a tariff supplement with supporting data to address that residual amount. The tariff supplement shall be served upon the Commission's Bureau of Investigation and Enforcement, the Bureau of Audits, the Office of Consumer Advocate, and the Office of Small Business Advocate at least ten (10) days prior to the effective date of the supplement.

RATE GR - GENERAL SERVICE -RESIDENTIAL

AVAILABILITY.

Service in the entire service territory of the Company to the dwelling and appurtenances of a single private family (or to a multiple dwelling unit building consisting of two to five dwelling units whether occupied or not), for domestic requirements of its members when such service is supplied through one meter. Resale of gas and/or service provided by the Company under this rate is only allowed for those locations being served through a single meter prior to January 6, 1980.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $19.95 per month
VARIABLE DISTRIBUTION CHARGE: $ 8.0763 per Mcf

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE (“CC”) (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE (“GCA”), GAS PROCUREMENT CHARGE (“GPC”), MERCHANT FUNCTION CHARGE (“MFC”), and BALANCING SERVICE COST (“BSC”) apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge. The Universal Service Fund Charge is incorporated in the Variable Distribution Charge.

CONTROLLED LOW PRESSURE SERVICE AND 2 PSIG DELIVERY.

For those Customers served from medium or high pressure mains, low pressure delivery of gas at 12.2 inches of water column or 2 PSIG will be provided upon request in lieu of the normal low pressure delivery. For these Customers multipliers of 1.03 will be applied to all meter readings for 12.2 inches of water column delivery and 1.14 for 2 psig delivery to recognize the additional volume of gas delivered.

BUDGET BILLING.

At the option of the Customer, budget billing is available in accordance with the provisions of Rule 16.5.

RULES AND REGULATIONS.

The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.

The initial term for any contract shall be at least one year.

PAYMENT TERMS.

Standard.

RATE GC - GENERAL SERVICE - COMMERCIAL AND INDUSTRIAL
(Effective as of January 1, 2026)

AVAILABILITY.
Service for use in commercial and/or industrial applications, with the right reserved to restrict its use as boiler fuel and for other non-critical use.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE:
$32.96 for service provided through a single small diaphragm meter
$61.30 for all other service

VARIABLE DISTRIBUTION CHARGE: $5.9332 per Mcf for all or any part of the first 200 Mcf
$5.8232 per Mcf for the additional use

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE (“CC”) (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE (“GCA”), GAS PROCUREMENT CHARGE (“GPC”), MERCHANT FUNCTION CHARGE (“MFC”), and BALANCING SERVICE COST (“BSC”) apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

CONTROLLED LOW PRESSURE SERVICE AND 2 PSIG DELIVERY.

For those Customers served from medium or high pressure mains, low pressure delivery of gas at 12.2 inches of water column or 2 PSIG will be provided upon request in lieu of the normal low pressure delivery. For these Customers multipliers of 1.03 will be applied to all meter readings for 12.2 inches of water column delivery and 1.14 for 2 psig delivery to recognize the additional volume of gas delivered.

BUDGET BILLING.
At the option of a Customer, budget billing is available in accordance with the provisions of Rule 16.5

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
Standard.

RATE OL - OUTDOOR LIGHTING SERVICE

AVAILABILITY.

Service for outdoor lighting by Company-approved lighting devices of the sizes hereinafter specified, where the consumption is not registered on a meter.

MONTHLY RATE TABLE.

		Distribution Charges	
Manufacturer's Rated Input to Lighting Devices	Nominal Mcf Rating Per Month	When Not in Conjunction With Service Under Other Gas Rates	When in Conjunction With Service Under Other Gas Rates
1,999 Btu/Hr.or less	1.5 Mcf	$11.0629	$5.5057
2,000 Btu/Hr.to 2,499 Btu/Hr.	1.7 Mcf	$12.8700	$7.8313
2,500 Btu/Hr.to 2,999 Btu/Hr.	2.1 Mcf	$14.4466	$8.9102
3,000 Btu/Hr.to 3,499 Btu/Hr.	2.4 Mcf	$16.1281	$10.6118

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE (“CC”) (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE (“GCA”), GAS PROCUREMENT CHARGE (“GPC”), and BALANCING SERVICE COST (“BSC”) apply to this rate.

INSTALLATIONS.

The Customer shall install, own and maintain the lighting devices and all tubing from the Company's service-supply pipe to the lighting devices.

FINAL CONNECTION.

The final connection of any lighting devices or tubing to the supply system shall be made by or under the supervision of a representative of the Company and the costs of such connections shall be borne by the Customer.

BUDGET BILLING.

At the option of the Customer, budget billing is available in accordance with the provisions of Rule 16.5

RULES AND REGULATIONS.

The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.

The initial contract term shall be at least one year.

PAYMENT TERMS.

Standard.

RATE L - LARGE HIGH LOAD FACTOR SERVICE

AVAILABILITY.

Large volume high load factor service for use in commercial and/or industrial applications, with the right reserved to restrict its use as a boiler fuel and for other non-critical use. This service shall be under a contract specifying in Mcf, the maximum daily quantity (MDQ) of natural gas to be supplied on a seasonal basis. The winter period MDQ may not exceed the summer period MDQ. Deliveries shall be as nearly as practicable at uniform hourly rates of flow.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $297.01 per month

VARIABLE DISTRIBUTION CHARGE: $9.9527 per Mcf for the first 50% of all usage.
$3.0231 per Mcf for the additional use.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE (“CC”) (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE (“GCA”), GAS PROCUREMENT CHARGE (“GPC”), and BALANCING SERVICE COST (“BSC”), apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

MINIMUM CHARGE.

The monthly minimum charge shall be the Fixed Distribution Charge.

MEASUREMENT.

The quantities of gas used shall be determined from the Company's meters, corrected to standard conditions, namely 60° Fahrenheit temperature and 30 inches of mercury barometric pressure.

UNAUTHORIZED OVERRUN.

Any quantity of gas taken for this service on any day of the month in excess of the MDQ specified in the contract for this service shall constitute unauthorized overrun volume for such day, except when such excess results from fluctuations in day-to-day deliveries hereunder determined by the Company to be normal and in accordance with good operating practices. The sum of all such unauthorized volume in a month shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily Weighted prices for a particular calendar month are summed and the result is equal to the MWP.

RULES AND REGULATIONS.

The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

MDQ DETERMINATION.

Each Customer shall review the contract annually and shall supply the Company written notification by August 1 of the Customer's requested MDQ(s) for the coming contract year. The MDQ requested shall be subject to reduction by the Company for either or both of the seasonal periods in light of available gas supplies, winter deliverability constraints, or for other good reason before the contract becomes effective. Any reduction made by the Company below the prior year's MDQ(s) shall be limited to the Customer's boiler fuel and other non-critical use.

The Company may, with the consent of the Customer, increase the existing winter MDQ up to the level of the contracted summer MDQ at such time during the winter period when, in the judgment of the Company, sufficient quantities of gas are available for the balance of the contract year.

TERM OF CONTRACT.

The initial contract term shall be at least one year.

PAYMENT TERMS.

Standard.

RATE MV-F MOTOR VEHICLE SERVICE-FIRM

AVAILABILITY.
Firm motor vehicle service is available to Customers using natural gas exclusively as fuel for motor vehicles.

MONTHLY RATE TABLE.

FIXED DISTRIBUTION CHARGE: $92.21 per month.

ADDITIONAL FIXED DISTRIBUTION CHARGE: If the Customer contracts with the Company for the installation and maintenance of compressor equipment to deliver gas at the necessary pressure for vehicle use, there will be an additional Customer Charge as specified in the Customer's contract.

VARIABLE DISTRIBUTION CHARGE: $1.4862 per Mcf

ADDITIONAL VARIABLE DISTRIBUTION CHARGE: If the Customer contracts with the Company for the purchase of compressed gas at a Company-owned refueling location, there will be a compression and refueling charge of $2.66 per Mcf added for each Mcf of gas supplied.

MINIMUM CHARGE: The minimum charge per month shall be the Fixed Distribution Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC), COMMODITY CHARGE (“CC”) (if customer receives Sales Service), GAS COST ADJUSTMENT CHARGE (“GCA”), GAS PROCUREMENT CHARGE (“GPC”), BALANCING SERVICE COST (“BSC”), and any applicable fuel taxes apply to this rate. The Consumer Education Charge is incorporated in the Variable Distribution Charge.

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
Standard.

RATE MV-I - MOTOR VEHICLE SERVICE-INTERRUPTIBLE

AVAILABILITY.

Interruptible motor vehicle service is available to Customers using natural gas for the sole purpose of a fuel for motor vehicles which have installed dual-fuel capability.

QUALITY OF SERVICE.

Upon notification by the Company, the Customer is required to transfer load to an alternate fuel. Under normal operating conditions, a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day. The Customer shall be responsible for maintaining alternate fuel equipment in good operating condition and arranging for adequate supplies of alternate fuel. Sales under this rate schedule are subordinate to all firm sales or firm transportation service provided by the Company.

MONTHLY RATE TABLE.
FIXED DISTRIBUTION CHARGE: $79.56 per month

ADDITIONAL FIXED DISTRIBUTION CHARGE: If the Customer contracts with the Company for the installation and maintenance of compressor equipment to deliver gas at the necessary pressure for vehicle use, there will be an additional Customer Charge as specified in the Customer's contract.

VARIABLE DISTRIBUTION CHARGE AND COMMODITY CHARGES:

Prices shall be established by the Company based on the alternate fuels that this Customer class has the economic capability of consuming.

The total of the Variable Distribution Charge and the Commodity Charge shall be no less than the allocated monthly cost of gas plus three cents, plus the applicable gross receipts tax factor.

The total of the Variable Distribution Charge and the Commodity Charge shall not exceed the sum of the end block of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost ("BSC") and the Gas Cost Adjustment Charge ("GCA") of Rate GC.

The Company will provide the Pennsylvania Public Utility Commission with written notification of the Rate MV-I prices on an unbundled basis at least eight (8) business days before the beginning of the month in which any price revision is to occur. Once established, the price will remain in effect from month to month unless changed by the above notification procedure.

ADDITIONAL COMMODITY CHARGE: If the Customer contracts with the Company for the purchase of compressed gas at a Company-owned refueling location, there will be a compression and refueling charge of $2.65 per Mcf added for each Mcf of gas supplied.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Charge.

STATE TAX ADJUSTMENT CLAUSE, DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) and any applicable fuel taxes apply to this rate.

OTHER CONDITIONS.

1. The Company reserves the right to enter the Customer's premises to inspect the equipment and apparatus at any time to determine whether the Customer's equipment and the Company's equipment is properly functioning, and whether the Customer is in compliance with all the provisions of this rate. It is the Customer's responsibility to inform the Company immediately if the Customer-owned or Company-owned control equipment does not operate properly.

2. Service under this rate may be separately supplied to a Customer who is also supplied under one or more other gas rates at the same premises, provided that each supply shall be separate and distinct with respect to delivery, metering and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

RATE MV-I - MOTOR VEHICLE SERVICE-INTERRUPTIBLE - Continued

3. Upon notification by the Customer to the Company that an emergency condition exists, the Company may, in its sole discretion, authorize the Customer to continue the use of gas during a period of interruption until such emergency condition has been corrected. The price of each Mcf of gas consumed during such emergency authorization will be increased by the difference between the allocated monthly cost of gas and the greater of:

a. The highest incremental supply cost incurred by the Company during the period such emergency service is provided;

b. The equivalent unleaded gasoline dealer tank wagon price as posted in the Journal of Commerce and as determined from the average of the three highest prices at Philadelphia for the month.

The Company may require affidavits or other documentation in order to verify the cause and duration of the emergency condition sustained by the Customer. The revenue received for Customer emergency service which is in excess of the normal Rate MV-I revenue will be returned to Customers by including the revenues in the GCA of the Sales Service Costs provision.

4. Any unauthorized gas consumed in violation of the provisions of this rate shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate. Such payment by the Customer for unauthorized use shall not be deemed as giving the Customer any rights to use such gas.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission). All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

5. Should the Customer cause the control device to be ineffective, or in any way change the operation thereof, all gas registered on the meter since the last meter reading, in addition to all other rates and charges, will be subject to the penalty charge shown above.

6. The Company may, after furnishing reasonable notice, permanently discontinue service to such Customer upon a finding by the Company that the Customer has not complied with the conditions and provisions of this rate.

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least one year.

PAYMENT TERMS.
Standard.

RATE IS - INTERRUPTIBLE SERVICE

AVAILABILITY.

Interruptible sales service is available to individual Customers who have dual-fuel capability or are willing to accept interruption of gas service. The Customer must have an estimated gas consumption of at least 3,000 Mcf per month during each summer month. The summer period includes the months of April through October. For a Customer that also receives service under Rates L, TS-I, or TS-F, the 3,000 Mcf per month use requirement does not apply.

Rate GC or other firm sales services may not be used as a backup supply during periods of interruption under this rate schedule. Rate GC service may be provided through separate metering where firm service is required. Piping connections between the firm and interruptible fuel line systems are prohibited.

The Customer will be required to execute a contract specifying the maximum daily quantity (MDQ) of gas that the Company's service and metering facilities are designed to supply. The maximum hourly capacity that the Company's facilities are designed to supply shall not be more than 6.5% of the MDQ.

QUALITY OF SERVICE.

Service under this rate is made available to Customers for purposes of balancing the Company's gas demands and optimizing its daily use of pipeline supplies and is strictly within the discretion of the Company. When the available quantity of gas is inadequate to serve the needs of all Customers under this rate, the Company will impose limitations, as necessary, endeavoring to provide each Customer with the opportunity to take gas from time to time. Under normal operating conditions, a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day. Those Customers who have dual fuel capability shall be responsible for maintaining alternate fuel equipment in good operating condition and arranging for adequate supplies of alternate fuel. Interruptible sales are subordinate to all firm sales or firm transportation service provided by the Company.

BILLING.

FIXED DISTRIBUTION CHARGE: $297.41 per month.

VARIABLE DISTRIBUTION AND COMMODITY CHARGES:

Prices shall be established by the Company based on the alternate fuels the Customer has the economic capability of consuming. The total of the Variable Distribution Charge and the Commodity Charge shall be no less than the applicable commodity cost of gas for the current month plus three cents, increased by the applicable gross receipts tax factor and shall be no higher than the applicable delivered price, on an equivalent BTU basis of alternate fuel.

The Company will provide the Pennsylvania Public Utility Commission with written notification of each of the prices on an unbundled basis at least eight (8) business days before the beginning of the month in which any price revision is to occur. Once established, prices will remain in effect from month to month unless changed in accordance with the above notification procedure. If there is a major change in competitive fuel prices during the month, the Company may change the Commodity Charge prices within the same upper and lower limits on notice of five working days to the Commission.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Charge.

METERING SEQUENCE.

Service under this rate may be supplied in combination with Rates L, TS-F or TS-I at a single point and through a single metering installation, in which case the MDQ for each rate schedule shall be specified in the contract. The Company will assume for billing purposes that metered volumes first reflect deliveries of the Contract Maximum Daily Quantity of Rate L gas, next the Firm Transportation Contract Quantity of Rate TS-F, next the Contract Quantity of Interruptible Transportation under Rate TS-I, and finally the Interruptible Gas under this rate schedule. Determination of Rate IS deliveries will be made at the end of the billing period. The number of Mcf billed under Rate L shall never be less than the number of Mcf resulting from 15 days' use of the Rate L billing demand.

STATE TAX ADJUSTMENT CLAUSE and DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) apply to this rate.

RATE IS - INTERRUPTIBLE SERVICE - Continued

OTHER CONDITIONS.

1. Any quantity of gas taken for this service on any day of the month in excess of the MDQ specified in the contract shall constitute unauthorized overrun volume for such day, except when such excess results from fluctuations in day-to-day deliveries hereunder determined by the Company to be normal and in accordance with good operating practices. The sum of all such unauthorized volume in a month shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission). All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

2. Upon notification by the Customer to the Company that an emergency condition exists, the Company may, in its sole discretion, authorize the Customer to continue the use of gas during a period of interruption until such emergency condition has been corrected. The price of each Mcf of gas consumed during such emergency authorization will be increased by the difference between the applicable commodity cost used to establish the current Rate IS Commodity Charge for the Customer and the greater of:

a. The highest incremental supply cost incurred by the Company during the period such emergency service is provided;

b. The equivalent No. 2 oil consumer tank car price as posted in the Journal of Commerce and as determined from the average of the three highest prices at Philadelphia for the month.

The Company may require affidavits or other documentation in order to verify the cause and duration of the emergency condition sustained by the Customer. The Company may, after furnishing reasonable notice, permanently discontinue service to such Customer upon a finding by the Company that the Customer has not complied with the conditions and provisions of this rate schedule.

The revenue received for Customer emergency service which is in excess of the normal Rate IS revenue will be returned to Customers by including the revenues in the GCA of the Sales Service Costs provision.

EXTENSION OF MAIN - INSTALLATION OF SERVICE.

Each Customer shall prepay the total cost of any main extension, service installation, meter installation, or enlargement or rearrangement of existing facilities required for service under this rate schedule.

RULES AND REGULATIONS.

The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least 1 year.

PAYMENT TERMS.
Standard.

RATE TCS - TEMPERATURE CONTROLLED SERVICE

AVAILABILITY

Temperature controlled service is available to individual Customers that have dual-fuel equipment with a rated input of more than 2,100,000 Btu per hour and an estimated fuel use which totals 5,000 Mcf or more during the billing months of December, January, February and March and are willing to accept interruption of service at the cut-off temperature specified by the Company.

QUALITY OF SERVICE.

Upon notification by the Company, the Customer is required to transfer load to an alternate fuel whenever the outdoor temperature is below the cut-off limit specified by the Company. Under normal operating conditions, a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day. During August of each year the Company will notify each Customer of the cut-off temperature limit to be effective during the twelve-month period beginning September 1. Those Customers who have dual fuel capability shall be responsible for maintaining alternate fuel equipment in good operating condition and arranging for adequate supplies of alternate fuel. Sales under this rate are subordinate to all firm sales or firm transportation service provided by the Company.

BILLING.

FIXED DISTRIBUTION CHARGE: $170.00 per month.

VARIABLE DISTRIBUTION AND COMMODITY CHARGES:

Prices shall be established by the Company based on the alternate fuels that this Customer class has the economic capability of consuming.

Monthly prices shall not exceed the sum of the end block of the Variable Distribution Charge of Rate GC, the monthly projected weighted average commodity cost of gas (WACCOG) and the Fixed Cost Credit determined in the most recent annual 1307(f) proceeding. Monthly prices shall be no less than monthly projected WACCOG and the 1307(f) Fixed Cost Credit, plus three cents. The Company will provide the Pennsylvania Public Utility Commission with written notification of the prices on an unbundled basis at least eight (8) business days before the beginning of the month in which any price revision is to occur. If there is a significant change in WACCOG during a month, the Company may change the commodity charge prices within the same upper and lower limits on notice of five working days to the Commission.

"Fixed Cost Credit" means the result derived by dividing the Company's annual projected interstate pipeline transportation and storage demand charges by its projected annual firm sales throughput as determined by reference to the Company's Section 1307(f) filing made immediately prior to the period in which the Fixed Cost Credit shall apply.

"Commodity cost of gas" shall include all purchased gas costs charged by the Company's natural gas and interstate pipeline suppliers on a volumetric or commodity basis (including but not limited to interstate pipeline fuel and the Company's company use and unaccounted for gas) and shall exclude all costs used in determining the Fixed Cost Credit.

MINIMUM CHARGE: The minimum charge per month will be the Fixed Distribution Charge.

STATE TAX ADJUSTMENT CLAUSE and DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) apply to this rate.

OTHER CONDITIONS.

1. The Company reserves the right to enter the Customer's premises to inspect the equipment and apparatus at any time to determine whether the Customer's equipment and the Company's equipment is properly functioning, and whether the Customer is in compliance with all the provisions of this rate.
It is the Customer's responsibility to inform the Company immediately if the Customer-owned or Company-owned control equipment does not operate properly.

2. Service under this rate may be separately supplied to a Customer who is also supplied under one or more other gas rates at the same premises, provided that each supply shall be separate and distinct with respect to delivery, metering and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

The Company may, in its sole discretion, permit minimal volumes of gas which would otherwise be supplied under Rate GC to flow through the Rate TCS metering where, in the Company's judgment, the cost of installing separate metering is uneconomical.

(Continued)

RATE TCS - TEMPERATURE CONTROLLED SERVICE – Continued

3. Upon notification by the Customer to the Company that an emergency condition exists, the Company may, in its sole discretion, authorize the Customer to continue the use of gas during a period of interruption until such emergency condition has been corrected. The price of each Mcf of gas consumed during such emergency authorization will be increased by the difference between the allocated monthly cost of gas and the greater of:

a. The highest incremental supply cost incurred by the Company during the period such emergency service is provided;

b. The equivalent No. 2 oil consumer tank car price as posted in the Journal of Commerce and as determined from the average of the three highest prices at Philadelphia for the month.

The Company may require affidavits or other documentation in order to verify the cause and duration of the emergency condition sustained by the Customer. The revenue received for Customer emergency service which is in excess of the normal Rate TCS revenue will be returned to Customers by including the revenues in the GCA of the Sales Service Costs provision.

4. Upon notification to the Customer by the Company that an emergency condition exists, the Company may change the threshold outdoor ambient temperature at which service is provided, for the duration of the emergency.

5. Any unauthorized gas consumed in violation of the provisions of this rate shall be billed at the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. The resulting amount shall be paid in addition to the charges specified in this rate. Such payment by the Customer for unauthorized use shall not be deemed as giving the Customer any rights to use such gas.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price.(In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

6. Should the Customer cause the control device to be ineffective, or in any way change the operation thereof, all gas registered on the meter since the last meter reading, in addition to all other rates and charges, will be subject to the penalty charge shown above.

7. The Company may, after furnishing reasonable notice, permanently discontinue service to such Customer upon a finding by the Company that the Customer has not complied with the conditions and provisions of this rate.

RULES AND REGULATIONS.
The Company's rules and regulations in effect from time to time where not inconsistent with any specific provisions hereof are a part of this rate schedule.

TERM OF CONTRACT.
The initial contract term shall be at least 1 year.

PAYMENT TERMS.
Standard.

GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS

(Applicable to: Rate TS-I Gas Transportation Service-Interruptible and Rate TS-F Gas Transportation Service-Firm.)

1. TRANSPORTATION SERVICE

1.1 GENERAL. Transportation service shall consist of: the receipt of gas on behalf of a Customer; the transportation of gas through the Company's distribution facilities, and the delivery of equivalent quantities of gas to the Customer, adjusted for thermal correction and system losses where applicable.

Transportation service may also include Standby Sales Service to permit purchases of gas under one of the Company's retail sales rate schedules.

1.2 TERMS DEFINED. The following definitions shall apply throughout the transportation portion of this tariff:

RECEIVED/RECEIPT shall refer to gas tendered to the Company for the Customer's account at one or more of the interconnections between the Company and its interstate pipeline suppliers, or other specified location. The normal unit of measurement is the dekatherm or mmBtu.

DELIVERED/DELIVERY shall refer to gas tendered to the Customer by the Company at the Customer's specified location. The normal unit of measurement is the Mcf.

USE/USAGE shall refer to gas actually consumed by the Customer at the specified location as measured by the Company's meter in Mcf.

DEFICIENT DELIVERIES shall refer to occurrences in which the Customer uses more gas than the quantity of transportation gas tendered by the Company for delivery.

EXCESS DELIVERIES shall refer to occurrences in which the Customer uses less than the quantity of gas tendered by the Company for delivery.

1.3 VOLUME ADJUSTMENT. The quantity of transportation gas received into the Company's distribution system for the Customer's account shall be: (a) reduced by 3.3% for system losses; and (b) adjusted for thermal correction determined by dividing the daily average Btu content per cubic foot of gas for the Company's system by a reference Btu content of 1,000 Btu per cubic foot. Where the transported gas can be delivered directly to the Customer without commingling with other system supplies, no reduction for system losses shall be made, and the thermal correction shall be based on the daily average Btu content of the pipeline to which the Customer is directly connected.

1.4 SUPPLY COST ADJUSTMENT. If the Company incurs any added gas supply cost in order to provide transportation service by displacement, or for other reasons, such additional cost will be charged to the Customer. Displacement occurs when a Customer, who is directly connected to one of the Company's pipeline suppliers, arranges for receipt of transportation gas on another pipeline to which the Customer is not directly connected. Revenues received by the Company in payment for added gas supply cost will be credited to firm sales Customers through the annual Sales Service Costs reconciliation (Section 1307[f]).

1.5 SERVICE AGREEMENT. The Customer will be required to execute a Transportation Service Agreement which will specify an initial Transportation Contract Quantity (TCQ) to be the maximum daily volume of gas, expressed in Mcf net of system losses where applicable, to be transported and delivered to the Customer. The agreement will also specify delivery locations, the election of Standby Sales Service, the commodity charge to be in effect for the term of the agreement, and any special provisions for service. The standard term for a Transportation Service Agreement shall be twelve months, unless the Company and the Customer agree to a shorter or longer term.

The TCQ shall not exceed the lower of (a) the capacity of the Company's metering and regulating equipment at the Customer's location; or (b) 110% of the maximum daily usage of the Customer during the twelve-month period prior to the execution of the Transportation Service Agreement, unless full documentation of new or additional gas usage capability is provided by the Customer. If a Customer chooses to designate an Agent to act on the Customer's behalf for scheduling, dispatching, billing and other administrative aspects of transportation service, such designation shall be made in the Transportation Service Agreement. The designation of an Agent shall not relieve the Customer of ultimate responsibility for payment for service or other obligations incurred under this tariff.

Every November 1 following execution of the Transportation Service Agreement, the Customer’s TCQ shall be automatically adjusted by the Company to be 110% of the maximum daily usage of the Customer during the prior twelve-month period if such adjustment would raise or lower the customer TCQ by the higher of either 10 mcf or 10%. The TCQ may also be adjusted by mutual agreement of the Customer and the Company.

(Continued)

GAS TRANSPORTATION SERVICE GENERAL TERMS AND CONDITIONS – Continued

(Applicable to: Rate TS-I Gas Transportation Service Interruptible and Rate TS F Gas Transportation Service Firm.)

1.6 BUYER GROUP/LEAD CUSTOMER. A Buyer Group generally consists of up to ten individual Customers who voluntarily join together to obtain either firm or interruptible transportation service. The Company, at its discretion, may require all members of the Buyer Group to execute the same Transportation Service Agreement and make the same elections as to Standby Sales Service. One member of the Buyer Group may be designated by the Company as the Lead Customer who shall be responsible for the timely payment of all bills rendered to the Buyer Group, as well as all day to day dispatch scheduling coordination and administrative communication between the Company and all members of the Buyer Group. A member of one Buyer Group may not be a member of another Buyer Group. Eleven or more individual Customers may form a Buyer Group only upon specific agreement by the Company. Unless otherwise described, the term "Customer" as used throughout these general terms and conditions shall refer to an individual Customer or to a Buyer Group. The Company, at its discretion, may set the maximum Commodity Charge for a Buyer Group at the maximum which any member would be individually required to pay.

1.7 MINIMUM SIZE. The minimum total gas consumption capability required to be eligible for transportation service shall be less than or equal to 5,000 Mcf per year. This minimum shall apply to an individual Customer or to a Buyer Group which, in the aggregate, uses less than or equal to 5,000 Mcf of gas annually.

2. BALANCING PROVISIONS

2.1 GENERAL. Transportation balancing is provided to adjust for the unavoidable minor variations between Customer usage and scheduled deliveries, and is not intended to function as a storage service or a standby sales service. Each Customer shall use best efforts to balance deliveries and usage at all times.

2.2 INTERRUPTED RECEIPTS. On days when no transportation gas is received for the Customer's account, all gas used by the Customer shall be billed as a purchase from the Company. For Customers which have elected Standby Sales Service, the usage shall be billed at the applicable rate. For Customers which have not elected Standby Sales Service, the usage shall be billed at the sum of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost (“BSC”) and, the Gas Cost Adjustment Charge (“GCA”) of Rate GC and a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf. Excess deliveries already being held for the Customer at the time of interruption will be tendered for delivery when transportation receipts resume. If the interruption of receipts continues for more than thirty days, the Company will tender excess deliveries as soon as practicable subject to operating and gas procurement considerations.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6, non-NY

North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

2.3 BALANCING CHARGE. A **$0.0229** per Mcf balancing charge shall be imposed on all transportation deliveries in a billing month. The Balancing Charge shall be reviewed and adjusted annually, as necessary, effective December 1 subject to approval of the new charge in the Company’s annual purchased gas cost filing under 66 Pa. C.S. § 1307(f)

2.4 ALLOWABLE DAILY VARIATION. In order to minimize the effect of transportation imbalances on the operation of the system, the allowable daily variation between delivered quantities and Customer usage is ten percent of the TCQ.

If a Customer exceeds these limits, the Company shall: (a) in the case of excess deliveries, impose a $0.25 per Mcf penalty charge on that portion of daily excess deliveries greater than the allowable daily variation and have the right to limit the receipt of Gas Transportation if a customer has excess deliveries greater than the allowable daily variation (b) in the case of deficient deliveries, have the right to bill such deficiency as a purchase from the Company. For Customers which have elected Standby Sales Service, the deficiency shall be billed at the applicable rate. For Customers which have not elected Standby Sales Service, the deficiency shall be billed at the sum of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost (“BSC”) and, the Gas Cost Adjustment Charge (“GCA”) of Rate GC, and a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6, Non-NY North Daily rate for such unauthorized usage day; or b) the Midpoint Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS - Continued

(Applicable to: Rate TS-I Gas Transportation Service-Interruptible and
Rate TS-F Gas Transportation Service-Firm.)

2.5 MONTHLY BALANCING FOR DEFICIENT DELIVERIES. If in any billing month a Customer has deficient deliveries, the volumes shall be billed at the applicable rate for those customers that have elected Standby Sales Service. For Customers which have not elected Standby Sales Service, the volumes shall be billed at the sum of the Variable Distribution Charge, Commodity Charge, Balancing Service Cost (“BSC”) and Gas Cost Adjustment Charge (“GCA”) of Rate GC, and a penalty charge based on the following: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 Non-NY North Daily rate for such unauthorized usage day; or b) the Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

2.6 MONTHLY BANKING SERVICE FOR EXCESS DELIVERIES. The Customer is permitted to carry over or bank a positive imbalance each month at the following monthly charges:

(a) where the monthly excess does not exceed the TCQ - $0.00 per Mcf;
(b) for the monthly excess greater than the TCQ and less than twice the TCQ - $1.00 per Mcf;
(c) for the monthly excess greater than twice the TCQ and less than three times the TCQ - $5.00 per Mcf;
(d) for the monthly excess greater than three times the TCQ - $10.00 per Mcf.

3. STANDBY SALES SERVICE

3.1 GENERAL. Standby Sales Service permits the Customer to purchase gas under one of the Company's retail sales rate schedules when:
(a) no transportation gas is received for the Customer;
(b) transportation deliveries are deficient with respect to the Customer's usage;
(c) a Customer elects to purchase gas from the Company in lieu of transportation service.

Transportation service under Rate TS-I automatically provides Standby Sales Service as described in Section 3.2 below. A Customer purchasing transportation service under Rate TS-F shall indicate in the Transportation Service Agreement if the Customer elects to have Standby Sales Service. If the Customer elects Standby Sales Service, the Customer shall specify the election in the Transportation Service Agreement as well as the Standby Sales Quantity (SSQ) which is the maximum daily quantity of gas expressed in Mcf that the Customer may purchase. A penalty charge based on the following will be imposed on volumes taken in excess of the SSQ: for the period November 1 through March 31, the applicable penalty for unauthorized use is the greater of (a) $75 per Mcf, or (b) the market rate as defined below for the cost of gas plus $25 per Mcf. For the period April 1 through October 31, the applicable penalty for unauthorized use is the greater of (a) $25 per Mcf or (b) the market rate as defined below for the cost of gas plus $10 per Mcf.

The term “market rate” shall mean the Monthly Weighted Price (MWP) which is applied to all unauthorized gas volumes. The MWP shall be calculated by first dividing the daily unauthorized usage (in Mcf) by the total monthly unauthorized usage (in Mcf) for each day of the calendar month when unauthorized usage occurs. This results in the daily weighting factor for each day of the calendar month when unauthorized usage occurs. Subsequently, each daily weighting factor is multiplied by the greater of a) the Midpoint of Transco, Zone 6 non-NY North Daily rate for such unauthorized usage day; or b) the Texas Eastern M3 Daily rate for such unauthorized usage day as reported in the Daily Price Survey published by Platts McGraw Hill Gas Daily or its successors, resulting in a daily weighted price. (In the event that Platts McGraw Hill Gas Daily or its successors ceases to publish these two indices, PECO will propose a reasonable substitute to the Commission.) All of the daily weighted prices for a particular calendar month are summed and the result is equal to the MWP.

The Company maintains no current or future duty to provide retail sales service to a Customer who declines to elect Standby Sales Service. Availability of Standby Sales Service for new gas loads not previously served under a retail firm sales rate schedule is contingent upon the Company's ability to arrange the required supply contracts.

3.2 INTERRUPTIBLE SERVICE. Interruptible Standby Sales Service under Rate IS is automatically provided to the Customer in conjunction with Rate TS-I. The billing and all other conditions of service shall be as stated under the Rate IS tariff, except that the Customer Charge shall be waived.

GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS - Continued

(Applicable to: Rate TS-I Gas Transportation Service-Interruptible and
Rate TS-F Gas Transportation Service-Firm.)

3.3 FIRM SERVICE. All Rate TS-F Customers may elect Standby Sales Service under:
(a) Rate L, for Customers with an SSQ of at least 100 Mcf per day and gas consumption capability of at least 18,000 Mcf per year;

(b) Rate GC, for Customers with an SSQ of less than 100 Mcf per day or gas consumption capability of less than 18,000 Mcf per year except that the Standby Sales Service rate schedule applicable to a Buyer Group may, at the Company's discretion, be set at the highest priced rate schedule under which any member would be individually required to pay. The billing and all other conditions of service shall be as stated in the applicable rate schedule and prorated for actual days of use, except that the Customer Charge shall be waived. In addition, the Customer shall pay a monthly demand charge per Mcf of SSQ which is based on 110% of the average monthly demand charges paid for the Company's firm supply. The monthly demand charge, prorated on an Mcf-per-day basis, will be credited to all volumes purchased. Following the end of the Company's supply contract year (October 31), the Customer shall also be assessed those minimum bill, take-or-pay, supply inventory, or other similar charges actually paid by the Company, which are attributable to the annual volume reserved but not taken under this provision. Customers that request to terminate Standby Sales Service after one or more years will be required to continue payment of the monthly demand charge until the Company is able to reduce its purchase obligations or otherwise utilize the released supplies.

4. OTHER PROVISIONS

4.1 METERING SEQUENCE. Where gas is used by the Customer under more than one of the Company's rate schedules through the same meter location, the Company will assume for billing purposes that metered volumes reflect deliveries in the following sequence where applicable:

(a) Rate L, up to maximum daily quantity.
(b) Rate TS-F, up to transportation contract quantity.
(c) Rate TS-I, up to transportation contract quantity, or actual delivered quantity, whichever is lower.
(d) Rate IS.

4.2 GAS SUPPLY SHORTAGE. The Company shall have the right to appropriate natural gas supplies to be delivered by or on behalf of a Customer in the event of a natural gas emergency (as defined in Rule 12 of the Rules and Regulations). In the event of a natural gas emergency, the Customer or its Natural Gas Supplier (NGS) shall continue to deliver all available natural gas supplies to the Company for which the Customer is contracted to purchase from the NGS. As compensation, the Company shall pay a price not in excess of the greater of the city gate cost of the appropriated natural gas, including transportation charges up to the Company’s city gate, or the reasonable cost actually paid by the customer for delivered substitute energy, as documented by the Customer. The Company may also provide compensation in kind at the discretion of the affected customer or NGS. Upon request, the Customer shall demonstrate its cost of natural gas by making a copy and invoice of the contract with the natural gas supplier available to the Company upon request.

(Continued)

4.3 LIABILITY.

(a) The Company shall not be liable for curtailment of service under this rate schedule or loss of gas of the Customer as a result of any steps taken to comply with any law, regulation, or order of any governmental agency with jurisdiction to regulate, allocate, or control gas supplies or the rendering of service hereunder, and regardless of any defect in such law, regulation, or order.

(b) Gas shall be and remain the property of the Customer while transported and delivered by the Company. The Customer shall be responsible for maintaining all insurance it deems necessary to protect its property interest in such gas before, during, and after receipt by the Company.

(c) The Company shall not be liable for any loss to the Customer arising from or out of service under this rate schedule, including loss of gas in the possession of the Company or any other cause. The Company reserves the right to commingle gas of the Customer with other supplies.

(d) The Company shall not be liable, under any circumstances or in any respect, to a Customer, to a gas producer or natural gas supplier, or to any other person or entity for damages arising either directly or indirectly from interruption, curtailment, or termination of transportation service.

TERM OF CONTRACT.

The initial contract term shall be at least one year.

RATE TS-I GAS TRANSPORTATION SERVICE-INTERRUPTIBLE

(Gas Transportation Service - General Terms and Conditions Apply To This Rate.)

AVAILABILITY.

Interruptible transportation service (Rate TS-I) is available to an individual Customer, or a Buyer Group, who may have dual fuel capability or is willing to accept interruption of gas service.

Service is available under this rate only to customers served by a licensed natural gas supplier who is deemed creditworthy by the Company pursuant to Rule 25 of the Rules and Regulations of the Gas Service Tariff.

High Volume Transportation (HVT) Customers receiving service under this Rate, as of March 1, 2002, shall be exempt from the above supplier eligibility criteria; provided, however, such an HVT Customer may waive such exemption, in a writing submitted to the Company, by indicating its desire to be served by a natural gas supplier deemed creditworthy by the Company pursuant to the above referenced Rule 25.

UPGRADING AND OR INSTALLATION OF FACILITIES.

Upgrading and/or installation of mains and services required to provide adequate delivery capacity for interruptible transportation service for the Customer will be in accordance with the Rules and Regulations governing Extensions. The Customer shall prepay the total cost of any new receipt point for Customer-owned gas into the Company system, or improvements to an existing receipt point, which then shall be constructed, subject to specific contract terms and conditions, owned, and maintained by the Company.

QUALITY OF SERVICE.

Interruptible transportation service will be provided on a best efforts basis by the Company and may be restricted or interrupted from time to time due to operating and capacity limitations. Under normal operating conditions a minimum of four hours' notice will be given before interruptions of service. The standard interruption of service will begin and end at 10:00 AM to coincide with the gas day. However, the notice period in emergency situations may be less than four hours and the Company may interrupt service at times other than the start of the gas day.

BILLING.

A. For each meter location having a gas consumption capability of at least 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE.
      $627.80 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $217.35.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The Variable Distribution Charge shall be $1.1735 per Mcf.

B. For each meter location having a gas consumption capability of less than 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE.
      $535.59 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $217.35.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual customer. The Variable Distribution Charge shall be $1.7293 per Mcf.

C. The State Tax Adjustment Clause does not apply to this rate.

D. DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) applies to this rate.

MINIMUM CHARGE.

The monthly minimum charge shall be the Customer Charge.

SEPARATION OF SERVICE.

Service under this rate may be separately supplied to a Customer who is also supplied under Rate GC at the same premises provided that each supply shall be separate and distinct with respect to delivery, metering, and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

PAYMENT TERMS.

Standard.

RATE TS-F GAS TRANSPORTATION SERVICE-FIRM

(Gas Transportation Service - General Terms and Conditions Apply To This Rate.)

AVAILABILITY.

Firm transportation service (Rate TS-F) is available to an individual Customer or a Buyer Group, who desires uninterrupted transportation service. Firm transportation service is not available with Rate GC through the same meter, except as provided under Standby Sales Service of the General Terms and Conditions.

Service is available under this rate only to customers served by a licensed natural gas supplier who is deemed creditworthy by the Company pursuant to Rule 25 of the Rules and Regulations of the Gas Service Tariff.

High Volume Transportation (HVT) Customers receiving service under this Rate as of March 1, 2002, shall be exempt from the above supplier eligibility criteria; provided, however, such an HVT Customer may waive such exemption, in a writing submitted to the Company, by indicating its desire to be served by a natural gas supplier deemed creditworthy by the Company pursuant to the above referenced Rule 25.

UPGRADING AND OR INSTALLATION OF FACILITIES.

Upgrading and/or installation of mains and services required to provide adequate delivery capacity for firm transportation service for the Customer will be in accordance with the Rules and Regulations governing Extensions. The Customer shall prepay the total cost of any new receipt point for Customer-owned gas into the Company system, or improvements to an existing receipt point, which then shall be constructed, subject to specific contract terms and conditions, owned, and maintained by the Company.

QUALITY OF SERVICE.

Transportation service under this rate schedule is firm and shall be interrupted only in cases of operating emergencies experienced by the Company or in the case of a natural gas shortage when the supply of gas is insufficient to meet the requirements of Priority 1 Customers.

BILLING.

A. For each meter location having a gas consumption capability of at least 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE
      $604.83 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $217.35.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The Variable Distribution Charge shall be $ 1.8670 per Mcf.
B. For each meter location having a gas consumption capability of less than 18,000 Mcf per year.
   1. FIXED DISTRIBUTION CHARGE.
      $466.67 per month less any Fixed Distribution Charges billed on other rate schedules for gas service through the same meter location; but in no event shall the Fixed Distribution Charge be less than $217.35.
   2. VARIABLE DISTRIBUTION CHARGE.
      The applicable Variable Distribution Charge shall be specified in the Transportation Service Agreement for each individual Customer. The Variable Distribution Charge shall be $2.7319 per Mcf.
C. The State Tax Adjustment Clause does not apply to this rate.
D. DISTRIBUTION SYSTEM IMPROVEMENT CHARGE (DSIC) applies to this rate.

MINIMUM CHARGE.

The monthly minimum charge shall be the Customer Charge plus 15 days' use of the TCQ at the Customer's applicable commodity charge.

SEPARATION OF SERVICE.

Service under this rate may be separately supplied to a Customer who is also supplied under Rate GC at the same premises provided that each supply shall be separate and distinct with respect to delivery, metering, and billing, and that no piping connections shall be made between the fuel line systems on the load side of the separate metering installation.

PAYMENT TERMS.

Standard.

RATE NGS - Negotiated Gas Service

AVAILABILITY. Service under this rate is available only to customers that satisfy the following criteria:

1. The customer either must have a history of at least 18,000 Mcf of annual natural gas usage billed by the Company. Alternatively, if a new customer, the customer must establish that the facilities to be served are likely to consume at least 18,000 Mcf of annual natural gas usage.

2. The customer must document a viable, currently available competitive alternative to service under the Rates GC, L, TS-F, or TS-I including any applicable riders. Documentation must include a written description of the competitive alternative and any further information necessary to establish the cost and demonstrate the viability of the customer's competitive alternative with reasonable certainty. The Company shall have sole discretion over whether the customer is eligible for a rate negotiated pursuant to this rate based on the information provided by the customer. If the customer already has in place a competitive alternative, the Company may require such written proof of the existence, nature, and working condition of such alternative, as the Company deems appropriate and necessary.

3. The customer executes an NGS agreement that comports with all other provisions of this rate.

4. As per Commission Order at Docket No. R-2020-3018929 (Order Entered June 22, 2021), the Company is required to provide an updated competitive alternative analysis to the Commission for any customer that has not had their alternative fuel source verified for a period of five years or more at the point when the Company files a base rate case.

QUALITY OF SERVICE. Service quality shall be negotiated and specified in each service agreement. Service quality may be firm, interruptible or a hybrid thereof. Priority 1 customers, however, shall be required to take firm standby service as a component of service provided under this rate schedule unless the customer demonstrates to the Company's reasonable satisfaction that it has an installed, operable backup system. Unless expressly stated in the service agreement, an interruptible customer shall bear the entire risk for any and all damages associated with an interruption.

NATURE OF SERVICE. The nature of service shall be negotiated and specified in each service agreement. Service may involve any one or more of the following services: supply; transportation; storage; upgrade or installation of mains, services, and appurtenant facilities; and such other natural gas management services the customer may require from time to time. The service agreement shall include all essential terms and conditions of the negotiated service. Where a term is not defined expressly in the service agreement, it shall have the meaning specified in the Tariff or, if the Tariff does not provide a definition, the meaning generally understood within the natural gas industry.

TERM LENGTH/NOTICE OF TERMINATION. The primary term length of a service agreement shall be no less than one year in length. Either the customer or the Company may terminate the agreement at the end of the primary term by giving written notice of termination at least one hundred-eighty (180) days before primary term ending date unless otherwise stated in the service agreement. If neither party gives such notice, then the agreement shall continue for consecutive one year terms until terminated by either party giving written notice of termination at least one hundred-eighty (180) days before the end of the continued term. Terms and conditions applicable to any continued term shall be stated in the service agreement.

RATES, CHARGES, BILLING.

1. Rates for service shall be negotiated and specified in the applicable service agreement. Rates negotiated for this service shall be presumed to have been designed to recover a fair rate of return on the incremental investment in facilities needed to provide service to the customer.

2. Rates will be, in the Company's sole judgment, competitive but the Company shall not be obligated to agree to charges that match the customer's costs under the customer's viable, currently available competitive alternative.

3. Unless otherwise stated in the service agreement, no charge of otherwise general applicability (e.g., State Tax Adjustment Clause) shall apply to service under this rate.

4. Unless otherwise stated in the service agreement, no charge applicable to other sales or transportation services offered under the Company's tariff (e.g., Rates GC, L, TS-I, TS-F) shall apply to service under this rate.

PAYMENT TERMS. Payment terms may be negotiated and specified in the service agreement. Unless the service agreement provides specific terms governing the billing of charges, Section 16. Standard Payment Terms of the Rules and Regulations of the Tariff shall apply.

RULES AND REGULATIONS. The Company's Rules and Regulations in effect from time to time, where not inconsistent with any provision hereof or the terms and conditions of the applicable service agreement, shall apply to a service agreement negotiated under this rate.

RATE NGS - Negotiated Gas Service - Continued

CREDITWORTHINESS

1. Prior to commencement of performance, or at any time during the term of service under this rate, Customer must provide financial information reasonably requested by the Company to ascertain Customer's ability to discharge its payment or other obligations under this rate. The Company shall be permitted to conduct financial evaluations during the term of the service agreement when information received by the Company indicates that the effective Credit Assurance has become unsatisfactory. The Company may charge $100.00 for each evaluation up to two evaluations per calendar year.

2. Based on the Company's initial or subsequent credit evaluation, the Company may refuse, suspend or terminate service under this rate if the Customer fails to deliver the requested credit information or assurance of its ability to pay within ten (10) business days of such request. Credit Assurance may include (i) the required posting of an irrevocable letter of credit acceptable to the Company, (ii) a cash prepayment in an amount acceptable to the Company, (iii) a corporate guaranty or (iv) other security acceptable to the Company.

3. Upon five days prior written notice ("Notice Period") to an NGS customer, the Company may suspend or terminate service to the customer upon the occurrence of a Default Event. A Default Event shall mean (i) the failure by the customer to make, when due, any payment or perform any obligation required under the service agreement, (ii) any representation or warranty made by the customer shall prove to have been false or misleading in any material respect when made, (iii) the customer is subject to a Bankruptcy Proceeding, or (iv) the customer fails to post satisfactory Credit Assurance. If the customer cures the Default Event within the Notice Period, service will be continued by the Company pursuant to the terms of the service agreement.

CONFIDENTIALITY/PENALTY FOR DISCLOSURE.

1. The terms and conditions of a service agreement executed pursuant to this rate shall be considered "Highly Confidential and Privileged" by the parties and by the Commission.

2. "Highly Confidential and Privileged" shall mean that disclosure to any third party, non-governmental entity is likely to cause the non-disclosing party pecuniary and competitive damage not easily susceptible to quantification.

3. Unless disclosure is otherwise permitted, each party to a service agreement under this rate must agree not to oppose a legal action by a party that is designed to enjoin or otherwise prevent the other party from disclosing the terms and conditions of such service agreement to a third party.

4. Service agreements may be disclosed to a third party only: a) upon prior written authorization by the parties to the agreement; b) as necessary for the parties to administer and enforce the agreement; c) to an agent, attorney or consultant of either party which has executed an agreement in which it acknowledges the "Highly Confidential and Privileged" nature of the service agreement and agrees to be subject to these Confidentiality/Penalty for Disclosure provisions set forth herein; or d) pursuant to the order of a court of agency having appropriate jurisdiction. Disclosure under b) or d) shall be permitted only after the parties to the service agreement have been provided adequate prior notice and opportunity to prevent such disclosure or to seek an appropriate protective order.

5. Any disclosure by the customer in violation of this provision shall result in a penalty equal to 10% of the otherwise applicable rate for the remaining term of the agreement, or as otherwise set forth in the service agreement.

EXCLUSION OF RATE NGS PURCHASED GAS COSTS FROM SECTION 1307(f) CLAIM

Purchased gas commodity and interstate pipeline demand costs, and associated quantities of natural gas purchased to provide service to customers served under Rate NGS, shall be excluded from the Company's annual purchased gas cost filing under 66 Pa. C.S. § 1307(f), in accordance with Exhibit RAF-1 submitted by the Company at Docket No. R-00016366.

APPLICABILITY INDEX OF RIDERS INTRODUCTORY STATEMENT

Customers under the different rates of this Tariff frequently desire services or present situations and conditions of supply which require special supply terms, charges or guarantees or which warrant modification of the amount or method of charge from the prices set forth in the rate under which they are supplied. Modifications for such conditions are defined by rider provisions included as a part of this Tariff. Riders may be employed when applicable, with or without signed agreement between the Customer and the Company as the case may require.

	PAGE	RATES TO WHICH RIDERS APPLY						
RIDERS	NUMBERS	GR	GC	OL	L	IS	TSI	TSF
Casualty	78	X	X	X	X	X	X	X
Construction	78	-	X	-	X	X	X	X
Neighborhood Gas	79	X	-	-	-	-	-	-
Receivership	81	X	X	X	X	X	X	X
Temporary Service	81	X	X	-	X	-	-	-
Weather Normalization Adjustment (WNA)	82	X	X	-	-	-	-	-
Customer Assistance Program	84	X	-	-	-	-	-	-

CASUALTY RIDER

APPLICABILITY. To service delivered during a period when a Customer is prevented for a length of time in excess of 48 hours from using all or a substantial part of the amount contracted for by reason of strike, riot, fire, storm, flood, drought, interference by civil or military authorities, or any other cause beyond the Customer's control.

NOTICE REQUIRED. Written request shall be made to the Company for the application of this rider with advice as to the extent of the interruption, its date, cause and probable duration.

GUARANTEES WAIVED. Guarantees of revenue under the Customer's contract shall be suspended during the period of the interruption, but shall be restored when the cause of interruption shall cease, be removed or remedied.

BILLS PRORATED. Bills for service supplied shall be prorated, based upon the actual level of operation during the period of suspension of guarantees.

RETURN TO NORMAL USE. The Customer shall use reasonable diligence in resuming the use of service provided in the Customer's contract.

TERM. The contract term shall be extended for a period equal to the period of suspension so that the Company shall secure a working term at full connected load equal to the term of the contract.

CONSTRUCTION RIDER

APPLICABILITY. To service supplied during a preliminary operating or construction period while the load is being built up to normal level or during a receding load period after the expiration of a standard contract term while a business is in process of dissolution.

GUARANTEE WAIVED. The guarantee minimum of a contract will be waived during the expanding load period preceding the operation within the load limits provided in the contract or the receding load period subsequent to the fulfillment of a contract term.

RIDER TERM. The total term of application of this rider during the preliminary or construction period shall be 6 months subject to the option of the Company to grant not more than two successive renewals of the rider term on major construction projects. Its application subsequent to the completion of a contract term shall be for not more than one year.

CONTRACT TERM. The termination date of a contract for service to permanent installations to which this rider is applied shall be extended for a period corresponding to the total time of the rider application during start up, construction or extension of the Customer's plant so that the Company will be assured the business represented by service to the total connected load for the term provided in the contract.

NEIGHBORHOOD GAS PILOT RIDER (NGPR)

AVAILABILITY
The Neighborhood Gas Pilot Rider (NGPR) is available to any existing residential neighborhood that: (1) applies for natural gas service within the Company's service territory under Rate Schedules GR or CAP; (2) would be required to pay the portion of the main extension and service line project costs that exceed the Company's capital investment under Rule No. 7 – Extensions of the Company's gas service tariff ("Rule No. 7") for an extension of the Company's distribution facilities needed to furnish natural gas service to a neighborhood; and (3) meets the Program Criteria set forth below.

The NGPR will close for new main extension projects on December 31, 2029 unless the Company decides to extend this program and the extension is approved by the Commission. The Company reserves the right to suspend the pilot program if, in its sole judgment, critical safety or reliability related issues require that the resources that would be used to implement the NGPR are needed to maintain safe and reliable natural gas service to its existing customers. The Company shall be the sole judge in establishing what constitutes a neighborhood when determining the availability under this pilot program.

NATURE OF THE NGPR
The NGPR provides customers in a neighborhood an alternative method of making the payment required by Rule No. 7 when the extension of distribution facilities needed to serve eligible new customers is not economically justified based on the anticipated revenues from natural gas distribution service that would be provided to customers served by such extension. The NGPR provides for a fixed charge (NGPR Charge) to be added to the customer's bill or an option to pay via a lump sum payment. The NGPR Charge shall be calculated separately for each main extension project and shall be based on the cost of that particular project in the manner described below for each customer served from such main extension project.

PROGRAM CRITERIA
For a main extension project to qualify for the NGPR, the neighborhood must consist of 2 or more existing residences, and the cost for such project must equal or exceed $15,000 and must meet the following additional criteria:

(1) A minimum of twenty percent (20%) of the existing residences located along the new main extension must commit to receive natural gas service by signing an agreement prior to the start of construction.

(2) The Company must have adequate system capacity to serve the customers that are eligible to receive natural gas service from the main extension; and

(3) The Company's total investment under this pilot program is limited to no more than $40,000,000 over five (5) years. The five-year extension period that this pilot program is in effect shall commence on January 1, 2025 and, as set forth above, shall close on December 31, 2029.

CALCULATION OF THE NGPR CHARGE
A Net Present Value (NPV) economic test (based on 40 years of revenue for each customer) shall be used to determine the payment required by Rule No. 7.

Pursuant to Rule No. 7, if the NPV of the capital investment (excluding 40 feet gas main allotment per existing residence) and the associated estimated revenues is less than zero, a customer is required to make a payment to the Company in an amount that would produce an NPV of zero, exclusive of any tax on the NGPR For purposes of this NGPR, however, in calculating the NPV, the anticipated revenues from natural gas service shall consist of: (1) the revenues from 20% (or greater) of eligible customers signing a contract prior to the start of construction to take natural gas service in the first year, which is one of the Program Criteria that must be satisfied for a project to be eligible for the NGPR; and (2) additional revenues will be applied in the first year based on the assumption a minimum of 66% of the eligible customers within the project area will sign a contract for natural gas service within 20 years of the completion of the project.

Capital investment shall include the total cost of new main(s) (excluding 40 feet gas main allotment per existing residence) and service facilities installed under the NGPR, excluding the costs of meters and meter installations, to serve eligible customers.

Estimated revenues shall be based on the applicable variable distribution charge rate set forth in the Company's gas service tariff, the estimated annual consumption and the portion of the fixed distribution charge that is attributable to the capital costs of a service line.

NEIGHBORHOOD GAS PILOT RIDER (NGPR) - Continued

Because the NGPR permits payment over time, rather than a lump-sum payment prior to the start of construction of main extension projects, as Rule No. 7 requires, the NGPR Charge will recover a reasonable return on the Company's capital investment in new facilities installed pursuant to the NGPR. For purposes of the NGPR calculation, the discount rate shall be determined on the basis of (1) the Company's capital structure and cost of long-term debt set forth in the Company's latest year-end Quarterly Earnings Report submitted to the Commission by March 31 of a year for the period ending December 31 of the previous year; and 2) the cost of equity approved in the most recent base rate case or, in the absence of a Commission determination or Commission approval of a stipulated cost of equity, the cost of equity that the Commission has determined should apply to Distribution System Improvement Charge ("DSIC") investment.

The NGPR shall be calculated to enable the project to have an NPV of zero based upon the above cost of capital. The resulting charge shall be increased by 1% by dividing the calculated rate by 0.99 to reflect an adjustment for uncollectible accounts expense.

BILLING

The NGPR Charge shall appear as a fixed monthly charge on the customer's bill.

The NGPR Charge calculated for a specific main extension will apply to all customers taking service from that main extension including any future customers that connect after the first year of the project.

For CAP customers, the NGPR charge will not be subject to the CAP discount.

If a customer fails to pay the full amount of any bill, a late payment charge of one and one-half percent (1.5%) per month will accrue on the portion of the bill that is unpaid on the due date.

PAYMENT TERMS

NGPR Charges shall be calculated based on input data specific to each project undertaken pursuant to the NGPR and shall be in effect for 20 years for each customer taking gas service from the main installed under this pilot within 20 years after the project has been completed.

The customer shall retain the right to pay the present value of the remaining monthly payments at any point in time during the 20 year period. Payments shall be present valued using PECO's after-tax cost of capital which shall be based on the sources as described above.

Service shall not be terminated for non-payment of this charge during the pilot program.

The STATE TAX ADJUSTMENT CLAUSE applies to this rider.

TRANSFER OF OWNERSHIP OF THE PREMISES

In the event the Premise transfers ownership after the Agreement Date, the obligation to pay any remaining amount of the NGPR Charge shall transfer to the new owner of the Premises. Prior to the transfer, the Owner must notify potential buyers or subsequent owners of the obligation to pay any remaining NGPR Charge associated with the Premises.

RECEIVERSHIP RIDER

APPLICABILITY. To service supplied a Receiver-Trustee for the continued operation of a property formerly under contract for its gas service requirements.

AUTHORITY FOR OPERATION. The Receiver-Trustee shall possess the authority under appointment by Court, through an order duly entered, to operate premises recited in a contract for gas service under which the Company has been supplying gas.

ACCEPTANCE. The Receiver-Trustee shall accept and adopt for the continuation of the supply of gas service the contract therefore in effect, including all of its provisions, and agree to pay the Company for all service furnished hereunder during the receivership-trusteeship at the rate specified therein.

BILLING. The Company reserves the right to render bills on a biweekly basis. To provide for biweekly billing under this rider, the provisions of the applicable rate and rider, if any, will be modified as follows:

(a) Where applicable, all references to monthly or month will be changed to biweekly or biweek.
(b) Where applicable, the commodity charge will be determined on a monthly basis and multiplied by 14/30ths (0.4667).
(c) The monthly rate per lighting device for Rate OL will be multiplied by 0.4667.
(d) The minimum charge will be determined on a monthly basis and such sum will then be multiplied by 0.4667 to determine the minimum charge for the billing period.
(e) A discount of 0.4% will be applied to the total bill.
(f) A bill will be rendered biweekly covering the charges for the preceding billing period and such bill shall be paid within fifteen (15) days after receipt thereof.

CONTRACT TERM. The completion of the term of the contract taken over, or as terminated by the discharge of the Receiver-Trustee, or as arranged with the Receiver-Trustee for the continuation of supply under the standard terms of this Tariff.

TEMPORARY SERVICE RIDER

APPLICABILITY. To the supply of service for a temporary period.

AVAILABILITY. Temporary service will be supplied only when the Company has available unsold capacity from which to furnish it and its supply will not in any way interfere with service to other Customers.

INVESTMENT IN SUPPLY FACILITIES. The cost of the connection and disconnection of the service supply and of any equipment and extension of facilities required to furnish the temporary service under the applicable rate shall be paid by the Customer, but such payment shall not confer upon, nor entitle the Customer to any title to, or right of property in, said facilities and equipment.

MINIMUM TERM. Application of this rider shall not, for billing purposes, be considered to be for a period of less than one month.

CONTRACT TERM. Short term arrangements as agreed upon.

WEATHER NORMALIZATION ADJUSTMENT (WNA)

APPLICABILITY AND PURPOSE

A Weather Normalization Adjustment (“WNA”) for natural gas service shall be included in monthly bills under Rate Schedules GR and GC for any bills rendered during the heating season (October through April). The WNA shall commence with bills rendered on and after January 1, 2027.

Calculated WNA amounts shall be subject to the State Tax Adjustment Surcharge (STAS) and the Distribution System Improvement Charge (DSIC).

COMPUTATION OF WNA
The WNA is a dollar value that will be included in billing periods from October through April. The Company shall calculate the WNA for each Rate GR and GC customer on an account-specific monthly basis using the formulas below:

WNBC = BLMC + [((NHDD +/- (NHDD * 5%)) / AHDD) x (AMC-BLMC)] WNAC = WNBC – AMC
WNA = WNAC x VDC(n)

In computing the WNA, pursuant to the formulas above, the following definitions shall apply**:**

- **WNBC -** Weather Normalized Billing Mcfs as defined in the formula above.

- **BLMC –** Base Load Monthly Mcfs.

  The Company shall establish a BLMC for each customer annually using the customer’s actual average daily consumption history, measured in Mcfs, from the two billing periods from the prior summer with starting meter read dates of June 15th, multiplied by the number of days in the billing period.

  If less than two billing periods of actual consumption history from the prior summer is available for a customer, the Company shall establish the BLMC for that customer using the average daily consumption per customer for all customers taking service under the applicable rate schedule.

- **NHDD –** Normal Heating Degree Days (“NHDD”) shall reflect heating degree days associated with “normal” weather during the billing period for the customer based on a 10-year average.

- **AHDD –** Actual Heating Degree Days (“AHDD”) shall be the actual experienced heating degree days during the billing period for the customer.

  If AHDD are unavailable for any day(s) during a billing period, the Company will also exclude the respective NHDD for the same day(s) from the calculation, thereby excluding any day(s) missing AHDD from the WNBC calculation for that billing period.

- **5% (Deadband) –** A threshold governing when the WNA is applied for a particular billing period.

  The Company shall apply a deadband of 5%. The WNA will apply for a given billing period only if the AHDD for that period are either lower than 95%, or higher than 105%, of the NHDD for that period.

  When the weather is colder than normal (i.e., AHDD>NHDD), the deadband percentage shall be multiplied by, and then added to, the NHDD for that period.

  When the weather is warmer than normal (i.e., AHDD<NHDD), the deadband percentage shall be multiplied by, and then subtracted from, the NHDD for that period.

- **AMC –** Actual Monthly Mcfs (“AMC”). The Company will measure this for each customer’s billing period. The WNA for a billing period will only apply if the customer’s AMC for that period are greater than their BLMC.

- **WNAC –** Weather Normalized Adjustment Mcfs (“WNAC”). The Company will calculate the WNAC by subtracting the customer’s AMC for the billing period from their WNBC.

WEATHER NORMALIZATION ADJUSTMENT (WNA) (continued)

- **VDC(n) –** Applicable Customer Variable Distribution Charge

- **WNA –** Weather Normalization Adjustment amount charged or credited to each customer served under the GR and GC rate schedules for the billing period.

The Company will calculate the WNA amount for that period by multiplying the WNAC by the applicable rate schedule's Variable Distribution Charge, including all applicable surcharges.

If the Company cancels and rebills a customer's bill for a given billing period, the Company will recalculate the WNA for that period using the most recently available data for that period. This may result in a different WNA calculation for the billing period. Bills requiring manual processing shall not have WNA applied.

Customer Assistance Program (CAP) Rider

AVAILABILITY:
To payment-troubled customers who are currently served under or otherwise qualify for Rate GR (excluding multiple dwelling unit buildings consisting of two to five dwelling units). Customers must apply for the rates contained in this rider and must demonstrate annual household gross income at or below 150% of the Federal Poverty guidelines. Customers will be subject to a $20 monthly bill minimum and will not be eligible to obtain Competitive Natural Gas Supply or participate in budget billing.

Based on the applicable level of income and number of household members, CAP customers will receive a fixed bill or Percentage of Income Payment Plan ("PIPP") based upon that individual household's need. The details of the PIPP calculation can be found in the PECO Universal Service and Energy Conservation Plan at Docket No. M--2018-3005795.

CERTIFICATION/VERIFICATION

Prior to enrollment in the CAP Rider, customers must verify, to PECO's satisfaction, that their household income level meets the "Availability" standards set forth in this Rider. Customers being considered for the CAP Rider will be required to:

- Provide information sufficient to demonstrate to PECO their household income level.
- Waive certain privacy rights to enable PECO to effectively conduct the above certification process.
- Participate in energy reduction and conservation programs offered by PECO if identified as high-usage.

PECO may, at its sole discretion, supplement this verification process by using data from Commonwealth or federal government programs which demonstrate the income eligibility of its customers. Such data may come from a customer's participation in, or receipt of benefits from, the Low Income Home Energy Assistance Program, Temporary Assistance for Needy Families, Food Stamps, Supplemental Security Income, and Medicaid. Information available from the Pennsylvania. Department of Revenue may also be used where appropriate to expedite the process.

MINIMUM CHARGE.
The minimum charge per month will be $20.

ARREARAGE.
Customers who qualify and are enrolled in CAP for the first time will have their pre-program arrearage ("PPA") forgiven if the customer pays his / her new, discounted CAP bill on time and in full each month. With every full and on-time monthly payment, one-twelfth of the PPA will be forgiven. PECO allows for customers who may have missed PPA "forgiveness" due to late or missed payments to "catch-up" on missed PPA forgiveness whenever a customer brings their bill current, PECO will forgive any missed forgiveness the customer did not receive during that time. If the customer develops any in-program arrearage while on the CAP Rate -- that is, if the customer does not pay the entire outstanding balance -- then preprogram arrearage forgiveness will not resume until the first month in which the full outstanding balance is paid.

PECO Statement No. 1:
Direct Testimony of Brendan J. Taylor

PECO ENERGY COMPANY
STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2026-3060860

DIRECT TESTIMONY

WITNESS: BRENDAN J. TAYLOR

SUBJECT: OVERVIEW OF RATE FILING; INTRODUCTION OF WITNESSES; CUSTOMER SERVICE OPERATIONS, PROGRAMS AND AFFORDABILITY; FULFILLMENT OF 2024 JOINT PETITION FOR SETTLEMENT COMMITMENTS; COMMUNITY ENGAGEMENT, WORKFORCE AND ECONOMIC DEVELOPMENT; MANAGEMENT PERFORMANCE

DATED: MARCH 30, 2026

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DIRECT TESTIMONY
OF
BRENDAN J. TAYLOR

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Brendan J. Taylor. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company as Vice President of Regulatory Policy and Strategy. My duties and responsibilities include regulatory strategy and policy, energy efficiency and energy acquisition for gas and electric activities at PECO.

3. Q. Please describe your educational background and professional experience.

A. I received a Bachelor of Science in Business Administration from the University of Delaware and a Master of Business Administration from Villanova University. During the past 19 years, I have held numerous positions within PECO and its parent, Exelon Corporation. Before becoming Vice President of Regulatory Policy and Strategy of PECO, I served as Director of Operations Analysis and Strategy at Pepco Holdings Inc. and was previously the Director of Finance at Pepco Holdings Inc. Prior to those roles, I held various positions of increasing responsibility in Exelon Finance. Prior to Exelon, I worked for a subsidiary of PNC Bank for four years as a Financial Analyst.

4. Q. **What are the purposes of your testimony?**

A. The purposes of my direct testimony are to (1) provide an overview of this rate filing and explain the factors that require increased investment to keep our gas infrastructure safe and reliable; (2) introduce the witnesses who will present testimony in support of PECO's case-in-chief; (3) discuss PECO's customer service operations and programs intended to help ensure rates are affordable and assist customers in saving energy; (4) discuss PECO's fulfillment of the commitments made by the Company as part of the settlement approved by the Pennsylvania Public Utility Commission (the "Commission") in PECO's 2024 gas base rate proceeding; (5) describe PECO's community work and support for economic and workforce development; and (6) address PECO's overall management performance in relation to the factors identified in Section 523 of the Public Utility Code.

II. OVERVIEW OF RATE FILING

5. Q. **Please summarize the relief that PECO is requesting through this rate filing.**

A. PECO has requested an annual overall natural gas rate increase of approximately $81 million. This filing also includes a request for approval of a Weather Normalization Adjustment ("WNA") as an alternative rate mechanism in accordance with 66 Pa. C.S. § 1330. The WNA would adjust certain customers' bills to reflect normalized weather conditions. PECO has designed its proposed WNA to be consistent with Columbia Gas of Pennsylvania's WNA mechanism, which was approved by the Commission on December 9, 2025. As required by the Public Utility Code, PECO's proposed tariff has been filed on 60 days' notice and, therefore, bears an effective date of May 29, 2026. However, we recognize that our filing will likely be suspended and investigated.

6. Q. Why is PECO requesting a rate increase at this time?

A. PECO is the largest combined natural gas and electric utility in the Commonwealth. PECO's gas operations serve a roughly 1,900 square-mile area in southeastern Pennsylvania. In addition to its supply and storage facilities, the Company's distribution system is comprised of approximately 7,350 miles of gas mains, approximately 484,300 gas services, and 28 gate stations. It takes considerable expertise and significant capital investment and operations and maintenance activities to provide PECO's customers with safe and reliable service. In 2024, our operations supported 11,500 jobs and $6.9 billion in economic impact in our region. And in 2026, despite the challenges posed by winter storms in January and February, we delivered consistent reliability performance and cost savings from the prudent use of peaking plant facilities.

We are committed to enhancing safety and reliability for our customers through new investments while supporting new business growth and integrating new technologies. We carefully align our operational, regulatory and financial plans to improve reliability, safety and service offerings and meet the evolving expectations and needs of our customers. Those new investments must also prepare for future growth in our service territory while taking into account the challenges of a changing climate and evolving technologies.

Between January 1, 2026 and December 31, 2027, the end of the fully projected future test year ("FPFTY"), we will have invested $790.9 million in additional natural gas distribution plant. A primary driver of our proposed rate increase is for necessary capital investment to continue to maintain and improve our distribution system and add new distribution plant to meet the increasing demand for reliable natural gas service throughout our service territory, including the necessary investment in PECO's information technology and communication systems, which all have positive benefits for customers. A significant amount of the remaining portion of the proposed increase is to expand our support for low-income customers given the increased costs to administer these programs.

While we continue to add new customers and modernize our natural gas distribution system infrastructure, our overall sales through 2027 are expected to increase only slightly.

As discussed in the testimony of Company witness Marissa Humphrey (PECO Statement No, 3), inflation and interest rates have remained elevated, raising the cost of investment and increasing the Company's labor, contracting, and materials expense. The Company has actively worked to mitigate the impact of these increased costs to keep our rates affordable, constraining controllable cost increases below the rate of inflation. However, as explained in further detail below and in the testimony of Company witness Ann E. Bulkley (PECO Statement No. 8), without an increase in revenues, PECO's overall returns on capital and common equity will be inadequate, impairing the

Company's ability to continue making the reasonable and prudent investments necessary to serve customers.

7. Q. Please provide an overview of the significant capital investments planned through December 31, 2027.

A. As discussed in detail in the testimony of PECO witness Chantee Angus, Vice President of Gas Operations (PECO Statement No. 2), the Company's capital investments are focused on system performance, capacity improvement, facility relocation, new business, and information technology ("IT"). Many of these investments are made in coordination with the goals and requirements of PECO's Long-Term Infrastructure Improvement Plan. Additionally, and as discussed in Ms. Angus' testimony, safety is a foundational element of PECO's capital investment strategy, with investments in equipment replacement, facility upgrades, and physical and cybersecurity measures supporting the highest standards of safety for employees, customers, and the gas system while enabling safe and reliable operations.

8. Q. What has PECO done to control expenses?

A. As in past years, we have continued to carefully manage our operations and maintenance ("O&M") expenses. As discussed by PECO Chief Financial Officer Marissa Humphrey in PECO Statement No. 3, PECO projects that its 2027 O&M expenses, excluding pension and bad debt expense (which are variable year to year and largely outside of the Company's control), will in fact decrease at an annual rate of 1.3% compared against the 2.6% projected average inflation rate for 2026-2027 (2.9% in 2026 and 2.4% in 2027).

These results reflect the Company's continued focus on leveraging both new and existing technologies and work practices to drive operational efficiencies. For example, PECO has expanded the use of horizontal directional drilling and vacuum excavation techniques, which reduce the number of street openings, shorten construction duration, lower restoration costs, and improve safety outcomes. In addition, investments in improved field data collection, digital work management systems, and advanced locating technologies have reduced rework, enhanced job planning, and supported more efficient deployment of labor and contractor resources. Nevertheless, as PECO witness Marissa Humphrey explains, despite our effective cost management, we do face continued cost pressures in a variety of areas that are not within our control, including elevated inflation that increases borrowing costs.

The Company is also proposing a WNA mechanism, which stabilizes customer bills and revenue recovery around Commission-authorized levels while protecting all customers from over-collection during colder-than-normal periods and mitigating under-collection during milder periods. The WNA mechanism is described in further detail in the testimony of Company witness John Taylor in PECO Statement 6.

Even with the effective cost control I have described, PECO's overall returns on capital and common equity will be inadequate without financial relief and impair the Company's ability to continue making the reasonable and prudent investments necessary to serve customers. PECO's proposed rate increase will ensure continuous, stable utility investment and operations that will help keep customer costs low even with the cost pressures that I have described.

9. Q. How have the Company's increased expenditures impacted its rate of return in invested capital?

A. Without an increase in revenues, PECO's gas operations are projected to produce an overall return on investment capital of 6.60%, and a return on common equity of 8.18%, during the 12 months ending December 31, 2027.[1] As explained by Ms. Ann E. Bulkley in PECO Statement No. 8, such levels of return are inadequate under any reasonable standard and below the rates of return generally afforded to public utilities. Absent a rate increase, the erosion in PECO's projected returns will impair the Company's ability to make all of the reasonable and prudent investments in gas distribution infrastructure that are necessary to maintain and enhance the provision of safe and reliable natural gas service to its customers. Inadequate returns would also negatively impact PECO's credit-coverage ratios and its ability to maintain its investment-grade credit ratings, thereby increasing the Company's financing costs, and ultimately the cost to customers, as further explained by Ms. Humphrey.

10. Q. Please identify the witnesses providing direct testimony on behalf of PECO in this proceeding.

A. In addition to myself, the following witnesses will be responsible for presenting PECO's case-in-chief:

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1 *See* PECO Exhibit MJT-1, p. 1.

Chantee C. Angus (PECO Statement No. 2) is Vice President of Gas Operations and oversees the daily operations of PECO's gas distribution system. Ms. Angus explains the responsibilities of the Gas Operations department and details our focus on capital investments to improve system reliability as well as our safety, security and environmental programs. She also addresses PECO's manufactured gas plant remediation efforts.

Marissa Humphrey (PECO Statement No. 3) is Senior Vice President, Chief Financial Officer and Treasurer of PECO. Ms. Humphrey discusses PECO's efforts to minimize customer costs and bills and provides an overview of PECO's principal accounting exhibits; discusses PECO's budgeting process; describes the services that PECO receives from affiliated entities and the estimated cost of those services during the FPFTY; and discusses the impacts of the Corporate Alternative Minimum Tax.

Michael J. Trzaska (PECO Statement No. 4) is a Principal Regulatory and Rates Specialist at PECO. Mr. Trzaska sponsors PECO Exhibits MJT-1, MJT-2, and MJT-3, which set forth PECO's revenue requirement for the FPFTY ending December 31, 2027, the future test year ("FTY") ending December 31, 2026, and the historic test year ("HTY") ended December 31, 2025, respectively. He supports PECO's rate base, revenue, operating expense and tax claims, as well as the Company's proposed Storm Reserve Account.

John Coursey (PECO Statement No. 5) is a Load Forecast Analysis Manager at Exelon. Mr. Coursey describes the development and results of PECO's gas sales forecast.

John Taylor (PECO Statement No. 6) is Managing Partner at Atrium Economics, LLC. Mr. Taylor describes the Company's proposed WNA mechanism and discusses the benefits that the WNA can bring to PECO's customers. He also explains how PECO's WNA is consistent with Columbia Gas of Pennsylvania's WNA mechanism, which was approved by the Commission on December 9, 2025.

Mariana Hufford (PECO Statement No. 7) is Director of Accounting at Exelon. Ms. Hufford describes PECO's accounting processes, supports the assignment and allocation of common costs between PECO's electric and gas operations, and explains the development of the depreciated original cost of the Company's utility plant in service and its claim for annual depreciation expense.

Ann E. Bulkley (PECO Statement No. 8) is a Principal at The Brattle Group. Ms. Bulkley presents testimony concerning the rate of return that PECO should be afforded an opportunity to earn on its rate base. She supports PECO's claimed capital structure ratios, its embedded costs of debt, and its requested equity allowance.

Jiang Ding (PECO Statement No. 9) is a Principal Regulatory and Rates Specialist at PECO. Ms. Ding presents an unbundled, fully allocated customer class cost of service study ("COSS").

Joseph A. Bisti (PECO Statement No. 10) is a Manager of Rate Analysts at PECO. Mr. Bisti presents PECO's proposed tariff rates and explains how the results of Ms. Ding's COSS, as well as the consideration of other factors, were utilized in the rate design process to develop PECO's proposed new rates.

Megan A. McDevitt (PECO Statement No. 11) is Senior Manager, Strategic Initiatives, at PECO. Ms. McDevitt discusses proposed changes and clarifications to PECO's gas service tariff.

Jacqueline F. Golden (PECO Statement No. 12) is Director of Customer Financial Operations at PECO. Ms. Golden discusses PECO's current universal service assistance programs, proposed revisions to PECO's Small Business Grant Program, certain customer service issues, the Company's reconnection fee waiver proposal, and information on PECO's natural gas rate case settlement commitment regarding payment processing fees.

Clifford Krausz (PECO Statement No. 13) is a Manager of Energy Efficiency Programs at PECO. Mr. Krausz discusses PECO's natural gas residential energy efficiency and customer programs.

III. CUSTOMER SERVICE OPERATIONS, PROGRAMS AND AFFORDABILITY

11. Q. What steps has PECO taken in recent years to enhance the quality of the customer service it provides?

A. Our customers expect customer service programs to be available on-line, comprehensive, and dynamic. PECO's mobile application and its website, www.peco.com, have many features that make it easier for a customer to sign up or move service, monitor usage, and enroll in electronic billing, automatic payments, or budget billing.

On average, the Company sends over 32 million notifications and confirmations to our customers on a yearly basis. As of the end of 2025, PECO now has 1.3 million customers enrolled in "MyAccounts" (approximately 74.3% of customers), which is an increase from 1.15 million (approximately 64% of customers) as of the end of 2023 and directly reduces our customer operations costs.

In order to help protect our customers, in 2024, we sent five educational email campaigns to customers regarding payment scams. These emails were sent to more than 5.7 million email addresses with an average open rate of 45%. In 2025, we sent six educational email campaigns to customers regarding payment scams. These emails were sent to more than 6.8 million email addresses with an average open rate of 48%. The emails reminded customers how to keep their personal, financial, and account information safe and what to look for from potential scammers.

PECO has a variety of other processes, features, and capabilities, including a multifactor authentication process to improve customer account security. This two-step verification is applied to all new customers, and 65.1% of existing customers are now enrolled.

We also provide customers with an "Assistance Finder" feature to aid customers with determining their eligibility to participate in programs providing energy or financial assistance, including energy efficiency programs. Since implementation in May 2023, nearly 30,000 customers have leveraged the Assistance Finder to receive personalized recommendations and application instructions for programs such as Deferred Payment Arrangements, Budget Billing, Due Date Extensions, and the Customer Assistance Program ("CAP").

12. Q. What do the results of customer surveys indicate about the Company's customer satisfaction?

A. The Company uses a research firm, Escalent, that conducts surveys with customers about their experiences with the Company based on drivers that measure customer satisfaction. According to an analysis of Escalent's survey results for 2025, the Company's top drivers of satisfaction included reliability, customer service performance, and safety.

Customer Operations also evaluates Escalent's measurement of call center satisfaction, as well as the results of customer satisfaction surveys, to monitor and continuously improve the Company's interactions with customers when they contact the call center.

The customer survey results indicate that PECO customers have high levels of customer satisfaction across the various key drivers. At year-end 2025, PECO Residential customer satisfaction was at 84%, with 91% of customers satisfied with PECO's reliability and 81% of customers stating that they believed it was easy to do business with PECO.

13. Q. How does the Company plan to continue improvement in customer satisfaction?

A. PECO recognizes its responsibilities to customers and is investing in maintaining and improving how the Company provides premier customer service and how it interfaces with customers. Customer Operations has focused on improving customer service through incorporating Generative Artificial Intelligence ("AI") into continuous improvement training of PECO's Customer Service Representatives, as well as incorporating more customer-requested features into the Company's web portal, My Account, and mobile apps.

One example of a new feature is PECO's recently implemented Service Installations and Upgrade Portal ("SIUP") that makes it easier for customers to request new or upgraded service by guiding them through a simpler, more accurate process. SIUP simplifies the customer request process by routing service requests to the correct backend workflow applications, reducing application errors, potential rework, and delays. The SIUP provides enhanced self-service capabilities for customers and reduces follow-up inquiries and administrative overhead, allowing employees to focus on critical infrastructure work. The systems are agile and allow future enhancements to improve efficiency and added features for customers.

Another example of using technology to enhance customer experience is through PECO's Planned Outage Notification ("PON") system, which keeps customers informed when a planned outage is scheduled or when work is needed to safely supply natural gas. Customers receive clear, timely, and personalized notifications that explain what to expect, including proactive alerts, updates, and notices if work is canceled or rescheduled. Information is delivered through the customer's preferred communication channels, helping customers plan ahead and stay informed with consistent, easy-to-understand messaging.

14. Q. Has the Company, since its last rate case, addressed the customer service and other issues described in the Statement of Chairman DeFrank on March 12, 2026 in Docket No. D-2025-3053971?

A. Yes. The Company's efforts to address customer service issues are addressed in the testimony of Ms. Golden. Ms. Angus describes the Company's efforts to manage employee overtime.

15. Q. Please describe PECO's leadership in the area of energy efficiency customer programs.

A. As explained by Mr. Krausz in PECO Statement No. 13, PECO's Natural Gas Energy Efficiency Programs provide a diverse portfolio of measures to customers seeking to reduce their energy consumption. Since 2022, the program has expanded to include additional increased ENERGY STAR equipment rebates, smart thermostat discounts, direct install measures, and a program for low-income customers providing no-cost measures focused on safety and efficiency. From 2024 through 2025, these programs have saved customers an estimated 99,673 Mcf through over 11,500 measures and households. Included in those savings are customers who received benefits under PECO's income-eligible Natural Gas Safe & Efficient Heating Program, funded by the Residential Natural Gas Energy Efficiency Program. Since 2022, the Safe & Efficient Heating Program has provided over $2 million in funding to replace eligible customers' space and water heating systems, who otherwise would not have received these benefits through other programs.

As further discussed in Mr. Krausz's testimony, the Company is proposing to expand these programs to continue to meet the demand of customers looking to energy efficiency programs for savings and set up new innovative pathways to drive energy savings and safety.

16. Q. Does the Company offer or administer programs to support the Company's low-income customers?

A. Yes. As described in the testimony of Jacqueline F. Golden in PECO Statement No. 12, PECO has a portfolio of universal service assistance programs designed to support low-income customers in maintaining affordable service, including the CAP, LIURP, Customer Assistance Referral and Evaluation Service ("CARES"), and Matching Energy Assistance Fund ("MEAF"), in addition to its support of Low-Income Home Energy Assistance Program ("LIHEAP").

17. Q. Is PECO taking other actions to assist customers with energy-related costs?

A. Yes, as further described by Ms. Golden, PECO is proposing to make changes to its Small Business Grant Program, which has been available to qualifying gas customers since 2021. Modifications intend to streamline the customer eligibility criteria to approve grant accessibility for small business customers.

Additionally, PECO is evaluating home services program models, similar to programs offered by other utilities in Pennsylvania, under which customers would be able to obtain maintenance plans from a third party for a variety of home repairs to protect themselves from large repair bills. While PECO has not yet introduced such a program for customers, PECO is proposing a tariff change that would flow all revenues PECO receives from any such program to customers. In PECO Statement No. 11, PECO witness McDevitt discusses the tariff changes necessary to arrange for such payments to customers in the future.

18. Q. In its Customer Assistance Program Policy Statement, the Commission states that "[i]n rate cases, parties may raise the issue of recovery of CAP costs, whether specifically or as part of universal service program costs in general, from all ratepayer classes. No rate class should be considered routinely exempt from CAP and other universal service obligations."[2] Did PECO consider making such a proposal in these proceedings?

A. Yes. We do believe it is appropriate to raise the issue in accordance with the Policy Statement and in the spirit of considering creative solutions to address customer affordability. However, I note that the Commission rejected such a proposal by the Office of Consumer Advocate and the Coalition for Affordable Utility Services and Energy Efficiency in our 2020 gas rate proceeding. While PECO is not making a proposal to shift universal service program cost recovery from residential customers in this proceeding, we propose that the Commission should initiate a collaborative to explore alternative mechanisms for recovery of universal service costs given the increasing costs of universal service programs. PECO believes that this is an issue that should be addressed not in a single utility proceeding but through a Commission-sponsored process in which

[2] 52 Pa. Code § 69.266.

utilities, advocates, stakeholder groups and customers throughout the Commonwealth can participate.

IV. FULFILLMENT OF 2024 JOINT PETITION FOR SETTLEMENT RATE CASE COMMITMENTS

19. Q. In the Joint Petition for Settlement of Rate Investigation that the Commission approved in PECO's last gas base rate proceeding at Docket No. R-2024-3046932 ("2024 Settlement" or "Settlement"), PECO agreed to report on various expenditures. Please describe each reporting requirement and PECO's compliance with this commitment.

A. First, PECO agreed to provide the Commission's Bureau of Technical Utility Services, the Commission's Bureau of Investigation and Enforcement ("I&E"), the Office of Consumer Advocate, and the Office of Small Business Advocate with an update on its gas division's actual capital expenditures, plant additions, and plant retirements by month for the 12 months ending December 31, 2024. Second, the Company agreed to provide a similar update on or before April 1, 2026, to include actual capital expenditures, plant additions, and plant retirements by month for the 12 months ending December 31, 2025. Finally, PECO agreed, in its next base rate proceeding, to prepare a comparison of its actual expenses and rate base additions for the 12 months ended December 31, 2025, to its projections in the 2024 gas base rate proceeding. PECO met each of these reporting commitments. PECO witness Humphrey describes the Company's 2025 actual expenditures further in her testimony.

20. Q. Please summarize PECO's compliance with other commitments in the Settlement directly affecting rates, customer programs, assistance to low-income customers, and gas safety.

A. ***Customer Assistance Programs ("CAP") (Settlement paragraphs 25-35).*** PECO has participated in the Department of Human Services ("DHS") data-sharing program and has used the data provided through the DHS program to automatically recertify current CAP customers. Additionally, PECO convened a stakeholder collaborative with its Universal Services Advisory Committee ("USAC") to discuss the automatic enrollment of non-CAP Low-Income Home Energy Assistance Program recipients in CAP. An additional collaborative will occur in 2026, and recommendations will be provided by October 1, 2026. Additionally, PECO met with its USAC on February 11, 2026, to develop a new procedure for obtaining informed consent for LIHEAP data sharing participants who want to enroll in PECO's CAP that does not require completing a new CAP application. PECO filed a revised Universal Service Energy Conservation Plan to outline the new process on March 12, 2026.

With respect to PECO's LIURP, PECO has met the settlement commitment of increasing the annual LIURP budget.

Regarding the MEAF, PECO made a compliance filing in its Universal Services and Energy Conservation Plan document to reflect amendments in maximum grant amounts and balance requirements to receive a MEAF grant. PECO also imposed data collection requirements on MEAF agencies and began reporting at quarterly USAC meetings statistics regarding the number of MEAF applications submitted, approved and denied by county, reasons for denials, and average processing time. PECO improved oversight of MEAF agencies in order to ensure appropriate termination holds on applicable accounts where MEAF applications have been approved. PECO also updated its website regarding additional information around the MEAF process and required documentation.

In addition, PECO fulfilled its commitments related to speech analytics software, usage of low-income status in the billing system to establish payment arrangements, review of inclusion of additional language in its ten-day termination notices around CAP, and provision of CAP and Universal Services information to Cold Weather Survey participants. PECO also fulfilled its commitments related to service reconnection at reduced restoration amounts and CAP enrollment of eligible low-income customers who were previously terminated.

Customer Service and Consumer Protection (Settlement paragraphs 36-42).

PECO investigated material issues with call handling identified in the 2022 Audit Report and filed a report on its investigation. PECO also reviewed, and will continue to review quarterly, accounts where security deposits were previously collected from confirmed low-income customers, then either refunded or applied, as appropriate. PECO also implemented changes to the security deposit letter regarding eligibility for a waiver. The Company also conducted an assessment to ensure Environmental Justice communities were not disproportionately impacted by service termination or security deposit requests and continued its Limited English Proficiency stakeholder meetings.

Related to payment processing, in this filing, PECO has provided information regarding residential payments by debit and credit card and, as discussed by PECO witness Golden in PECO Statement No. 12, has provided information explaining why the Company has not made a proposal to eliminate payment processing fees. PECO continues to negotiate lower payment processing fees with third-party vendors.

Gas Safety (Settlement paragraphs 43-49).

PECO has met all commitments related to gas safety, including improving the consistency and accuracy of field leak reporting through training and awareness, performing quality audits of at least 10% of field leak repair reports, building a new Power BI dashboard to better present and analyze risk more granularly, and adding more factors into the risk model and incorporating them into the Synergi software. Additionally, PECO continued to identify inaccurate facilities, included more information (including color coding) in gas safety brochures, tracked post construction quality audits containing a failed observation, and continued investment in technologies that facilitated mapping improvements and removal of potentially hazardous pipeline components. A meeting was held with Commission Pipeline Safety inspectors to demonstrate how the above items were satisfied.

Customer Programs (Settlement paragraph 50).

PECO met its commitment to increase the amount of the natural gas energy efficiency budget.

V. ECONOMIC DEVELOPMENT, WORKFORCE DEVELOPMENT, AND COMMUNITY ENGAGEMENT

21. Q. Please describe PECO's efforts to support economic development and the communities in which the Company provides service.

A. PECO has a dedicated Economic Development Team that works cooperatively with local, regional, and state economic development officials, as well as commercial and industrial real-estate professionals, to assist businesses that are considering locating or expanding in southeastern Pennsylvania. For example, the team provides information on electric and gas availability and prices to companies, developers, and consultants as key inputs to location decisions. The team also works with developers on electric and gas infrastructure strategies for large development sites.

In 2025, PECO's efforts to drive economic growth and job creation across southeastern Pennsylvania were recognized for the 15th time by *Site Selection Magazine*, "…an award-winning magazine recognized as the leading publication in corporate real estate, facility planning, location analysis and foreign direct investment." In 2025 alone, PECO helped secure 15 new commercial projects that are collectively set to add 7,429 jobs at their facilities and more than $21.3 billion in local investment.

Additionally, as I discussed earlier, PECO makes significant capital and infrastructure investments in its service territory every year that create and maintain thousands of jobs in the region. The Company regularly hosts a Gas Mechanics School ("School") to develop a hiring pool for gas operations personnel, in 2024 and 2025, the Company held a School annually and hired 20 candidates each year. Interest in gas mechanic positions is high, with the Company receiving at least 750 applications for each School. The Company intends to host additional Schools in 2026 and 2027 and has plans to hire 20 additional individuals each year.

22. Q. Are there other ways in which PECO and its employees support their communities?

A. Yes. In 2025, PECO advanced its role as an anchor institution by aligning Corporate Community Impact ("CCI") activities with core objectives related to customer affordability, community resilience, and workforce readiness. Through coordinated, enterprise-wide efforts, PECO delivered initiatives designed to expand access to energy assistance, strengthen community infrastructure, and support development of a skilled workforce across its service territory. These initiatives were structured to produce measurable outcomes and to complement the Company's broader operational and regulatory priorities.

One of PECO's primary focuses in 2025 was maintaining energy affordability for customers experiencing financial hardship. PECO expanded direct customer outreach to increase awareness of, and access to, available assistance programs by delivering information and support through community-based locations and digital channels. During the year, PECO conducted 349 outreach events, resulting in approximately 25,000 customer touchpoints and exceeding established outreach targets. In addition, PECO hosted 38 Virtual Assistance Sessions that provided individualized support with eligibility determination, applications, and documentation. These sessions assisted 1,824 customers live, with an additional 1,075 customers supported through follow-up engagement. These efforts contributed to increased participation in key affordability programs. Enrollment in CAP reached approximately 137,000 customers at the end of 2025, an increase of 12% from year-end 2024.

Participation in the Gift of Energy program also increased materially, with contributions rising 108% and providing more than $42,000 in direct bill credits supporting 182 customers facing short-term hardship. PECO further supported effective delivery of assistance by collaborating with 23 Neighborhood Energy Centers to ensure accurate, up-to-date guidance for customers seeking help. In addition, in its role as Pennsylvania's state lead for LIHEAP outreach, PECO supported the delivery of $17.28 million in LIHEAP bill assistance during Fiscal Year 2024–2025, including $2.42 million in supplemental grants.

Further, in 2025, PECO expanded its affordability strategy with the launch of the Customer Relief Fund ("CRF"), a $10 million initiative designed to provide immediate bill assistance to limited- and moderate-income households experiencing rising energy costs. The CRF became available on August 4, 2025, and is administered in partnership with the United Way of

Greater Philadelphia and Southern New Jersey. The CRF is designed to support customers who may not qualify for traditional assistance programs and was integrated with PECO's existing portfolio of affordability offerings, including CAP, LIHEAP, and MEAF.

Building on the strong foundation of the original Customer Relief Fund, PECO launched CRF 2.0 on March 2, 2026, adding an additional $2.5 million to further strengthen support for households facing rising energy costs. This expanded phase continues PECO's commitment to reaching our most vulnerable customers by focusing on those whose household incomes are at or below 150% of the Federal Poverty Level.

In addition to affordability initiatives, PECO invested in programs that support neighborhood stability, environmental resilience, and community wellbeing. Through the Green Region Open Space Program, PECO awarded more than $200,000 in grants during the program's 20th year to support community-led improvements of local open spaces. PECO also provided $150,000 in grants through the Powering the Arts program to nonprofit organizations that promote community connection and revitalization. In partnership with the Pennsylvania Horticultural Society, PECO supported the planting, sorting, and distribution of more than 1,000 trees to improve air quality, mitigate heat-island effects, and assist with stormwater management within its service territory. PECO employees further supported these efforts through volunteerism, contributing 26,140 hours of service across 393 nonprofit organizations—from preparing thousands of meals at MANNA on

Thanksgiving morning, to installing free smoke alarms with the Red Cross, to Love Your Park clean-ups and back-to-school drives.

PECO also invested in initiatives designed to strengthen nonprofit governance and long-term community capacity. In 2025, PECO launched its first 3C (Community, Connection, Commitment) leadership cohort, engaging 38 employees from across the Company to promote service, partnership, and learning. PECO also expanded participation in nonprofit board service by offering quarterly governance training in partnership with La Salle University, resulting in 14 employees joining boards focused on housing, education, and community development.

Workforce development also remained a key focus for PECO in 2025, with initiatives designed to establish clear pathways into family-sustaining careers in the utility sector. PECO hosted its seventh Infrastructure Academy, engaging more than 160 participants in hands-on demonstrations, testing preparation, and structured interviews. Since the Academy's inception in 2020, more than 70 participants have been hired into PECO roles. PECO also launched Helper Pre-Apprenticeship Cohort 4 with 16 participants, many referred through community partners, to accelerate readiness for critical operational roles. Additional investments included a regional high-school internship program, a Junior Infrastructure Academy serving 80 students, and multiple STEM engagement initiatives. PECO further supported education access by awarding 70 scholarships during Academic Year 2024–2025 and initiating 22 additional scholarships for Academic Year 2025–2026 at colleges, universities, and community colleges.

PECO's community investments are structured as strategic partnerships that complement the Company's operational objectives and regulatory obligations. Taken together, these initiatives support improved customer stability, strengthened community infrastructure, and development of a qualified workforce necessary to maintain and modernize PECO's gas distribution system.

Since 2021, PECO's corporate contributions and employee giving campaigns (including corporate matching gifts) have invested more than $38 million dollars in hundreds of local and regional non-profit programs, organizations, and institutions that provide access to arts and culture, and support STEM education, the environment and green spaces, community vitality, workforce development, and reduction of gun violence. And PECO, along with other Exelon operating companies and the Exelon Foundation, created a $36 million Community Equity Capital Fund to begin establishing access to capital for small businesses from under-resourced communities so that they can create more jobs, grow their companies, and reinvest in their neighborhoods and communities. Notably, in 2023, PECO was named a recipient of The Civic 50 Greater Philadelphia Award by Philadelphia Foundation, in partnership with Points of Light, for superior corporate citizenship in utilizing the Company's time, skills, and resources to drive social impact within the Company and the communities PECO serves.

PECO has been recognized with several awards for its community engagement and workforce development including the OIC of Philadelphia's Workforce Partner Award, which was awarded during the 60th Anniversary Gala, Partners in Philanthropy Award from the *Philadelphia Business Journal* (in partnership with Beyond Literacy), CEWD Community Partner Impact Award - (national organization), PECO Innovation Award Trailblazer - (Junior Infrastructure Academy), and the City of Philadelphia's Employer of Choice Award.

PECO will continue to focus on removing barriers to access, strengthening partnerships, and investing in initiatives that support safe, reliable, and resilient gas service for customers across its service territory.

VI. MANAGEMENT PERFORMANCE

23. Q. Mr. Taylor, is PECO requesting an enhanced return on equity based on its management performance?

A. No. PECO is not seeking an enhanced return on equity tied to management performance, although our results reflect disciplined, effective management focused on reliability, customer value, and cost control.

VII. CONCLUSION

24. Q. Does that complete your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060860**
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Brendan J. Taylor, hereby state that I am a Vice President of Regulatory Policy & Strategy for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 1 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Dated: March 30, 2026

Brendan J. Taylor

PECO Statement No. 2:
Direct Testimony of Chantee C. Angus

PECO ENERGY COMPANY
STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2026-3060860

DIRECT TESTIMONY

WITNESS: CHANTEE C. ANGUS

SUBJECT: PECO'S GAS OPERATIONS; PECO'S CAPITAL INVESTMENT PROCESS; SYSTEM SAFETY AND RELIABILITY AND EMPLOYEE SAFETY; MANUFACTURED GAS PLANT REMEDIATION PROGRAM; SECURITY, AND ENVIRONMENTAL PROGRAMS

DATED: MARCH 30, 2026

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DIRECT TESTIMONY
OF
CHANTEE C. ANGUS

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Chantee C. Angus. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as the Vice President, Gas Operations. In that capacity, I am responsible for the administration of PECO's natural gas distribution system, including construction and maintenance, engineering, plant operations and distribution system control, new business, environmental management and regulatory compliance. I have been performing these functions since September 2025.

3. Q. Please describe your educational background and professional experience.

A. I hold a Bachelor of Science degree in Business Management from Hampton University. I have been continuously employed by PECO since April 2013. My initial position was Manager of Financial Planning and Analysis. Since that time, I have held multiple roles of increasing responsibility, including positions within PECO's Financial Operations Department, serving as Chief of Staff to PECO's Chief Operations Officer, Director of Regional Electric Operations, and Director of Utility Training. In September 2025, I was promoted to my current role.

4. Q. What is the purpose of your testimony?

A. The purpose of my testimony is to: (1) generally describe PECO's natural gas operations and how the Company leverages available tools to drive efficiencies and increase productivity for the benefit of our customers; (2) explain PECO's capital investment process and identify, by major plant category, PECO's claimed future test year ("FTY") and fully projected future test year ("FPFTY") plant additions; (3) discuss the Company's actions to ensure the safety and reliability of PECO's natural gas distribution system, including employee safety; (4) support the Company's claim for manufactured gas plant ("MGP") remediation expense; and (5) describe measures taken by the Company with respect to security and its environmental impact.

II. DESCRIPTION OF GAS OPERATIONS

5. Q. Please provide an overview of PECO's gas operations.

A. PECO is the largest combined electric and natural gas utility in Pennsylvania. In addition to the approximately 1.7 million electric customers we serve, PECO provides natural gas service to over half a million customers. PECO's natural gas service region is located throughout a 1,900 square-mile area in southeastern Pennsylvania adjacent to, but exclusive of, the City of Philadelphia. The Company's natural gas service territory comprises all or portions of Bucks, Chester, Delaware, Montgomery and Lancaster counties and includes a total population served of approximately 2.6 million people.

6. Q. What services does PECO offer its natural gas customers?

A. PECO makes available both bundled and unbundled natural gas service. Most of our customers have elected a bundled service, whereby PECO procures and delivers natural gas to their home or place of business. With the advent of transportation service in the 1980s and the passage of the Natural Gas Choice and Competition Act in 1999, customers also have the option to procure their own natural gas supply and pay PECO for delivery service only. In addition, and as set forth in our natural gas tariff, qualifying customers can avail themselves of a variety of firm, interruptible and temperature-controlled services.

7. Q. How does PECO's customer base break down by major customer classification?

A. As of December 31, 2025, PECO served approximately 510,959 residential customers; approximately 44,698 small commercial and industrial customers; and seven unique large commercial and industrial customers. Residential customers account for 47% of total metered volume.

8. Q. What are the major assets and facilities that PECO utilizes to provide natural gas service to its customers?

A. The natural gas PECO delivers to its customers is procured through contracts with third-party suppliers. PECO transports and stores natural gas for its customers on four interstate pipelines that are interconnected with its distribution system. In addition, to supplement pipeline supply on an as-needed basis during peak-demand periods, PECO operates a liquefied natural gas ("LNG") plant in West Conshohocken and a propane-air peaking plant in Chester. PECO uses these peaking plants to store natural gas during the summer when prices are low and employs this low-cost natural gas to meet winter peak-demand, thereby reducing natural gas supply costs for our customers. For example, during the winter storms of January and February 2026, PECO utilized these peaking plants for nine days to serve peak-demand, which resulted in natural gas supply cost savings to our customers of over $20 million when considering the cost of gas supply in the spot market at the time.

In the last ten years, PECO has invested in two new portable vaporizers, three LNG transport trailers, two portable storage tanks, and off-loading facilities built to handle LNG transport trailers that are located at the West Conshohocken LNG plant, East Greenville Gate Station, and Parkesburg Gate Station. To increase the reliability and efficiency of the boil off system at the West Conshohocken LNG plant, PECO commissioned two new boil off compressors and placed them into service as of January 2022. In 2023, PECO completed the construction and commissioning of new vaporization equipment at the West Conshohocken LNG plant, replacing assets from the 1970s. This equipment provides PECO with the ability to vaporize at a higher pressure and has a 100% built-in redundancy.

In addition to its supply and storage facilities, PECO operates approximately 7,350 miles of low, medium, high, and over-high-pressure gas mains, 484,300 gas services and 28 gate stations that feed its distribution system. PECO's purchased gas costs are recovered through a separate Section 1307(f) rate mechanism, which is reviewed and reconciled annually. Those costs are not part of the increase requested by this filing.

III. PECO'S CAPITAL INVESTMENT PROCESS

10. Q. How does PECO determine its annual capital investment requirements?

A. PECO's annual capital investment plan begins with a detailed budgeting and long-range plan development process. A key goal of that process is to integrate and align capital investments with PECO's strategic operational, regulatory, and financial plans. The mix of capital investment needs can change from year to year and is the product of a variety of factors, including trends in the housing market, emergent operational constraints, local municipality workloads and, most importantly, the condition of existing facilities.

Projects requiring a capital investment of over $1.5 million ("Major Projects") are subject to an additional, rigorous committee review process that includes senior management control of project scope and contract strategy. The primary goals of the process are to ensure that:

(1) the technical merits of each Major Project are balanced with the economic and customer benefits and goals of the Company;

(2) Major Projects are properly researched, developed, planned, reviewed, and authorized by senior management before significant resources are committed or expended; and

(3) decision points for consideration and approval of any additional funds are established as the details of Major Projects evolve.

The Company's annual capital investment process is designed to ensure that PECO's investments fully support safety, reliability, and customer service goals as well as achieve an optimal operational efficiency.

11. Q. How does PECO's annual capital investment process impact jobs in its natural gas service territory?

A. PECO invests significant capital in maintaining existing and developing new natural gas distribution infrastructure that not only supports thousands of jobs in the region but also creates new jobs each year. In July 2025, the Company held a school and hired twenty graduating individuals. Interest in the school remains strong, with the Company receiving an average of more than 750 applications per year over the last two years. Due to this continued demand, the Company intends to host additional schools in both 2026 and 2027.

12. Q. What are PECO's primary categories of investment for its natural gas operations?

A. Annual capital investment requirements are evaluated on a functional level and are primarily placed into categories that include (1) system performance, (2) capacity improvement, (3) facility relocation, (4) new business, and (5) information technology ("IT"), each of which is described below.

System performance projects are evaluated based upon factors specific to the appropriate replacement program and then prioritized for replacement in a given year. These projects target aging infrastructure based on field observations and a review of program-specific performance metrics. Projects are ranked within their respective programs based on certain criteria including, but not limited to, age of main, repaired leaks/breaks, main pressures, active leaks, customer considerations, cost to replace versus cost to repair, condition of main, and environmental factors.

Capacity improvement projects prevent system pressure from dropping below design standards and relieve capacity-constrained areas that prevent the addition of new customers. These improvements enable the system to safely accommodate future customer growth while enhancing reliability, service quality, and operational flexibility for both new and existing customers.

Facility relocation projects move natural gas facilities away from conflicting township and state road improvements. Since natural gas facilities are within the public right-of-way of roadways, these facility relocation costs are borne by PECO.

New business projects support residential and commercial customer requests for new natural gas service, an upgrade of existing service and the relocation of natural gas facilities. PECO introduced a new customer Service Installations and Upgrade Portal that will allow customers to submit utility service requests with ease. A simplified, guided application will help customers submit requests for desired work for PECO to complete. The system automatically determines the appropriate application(s), minimizing time spent on completing customer requests.

Finally, in the area of IT infrastructure, many of our capital projects drive operational improvements and efficiencies, reduce risk, increase reliability, and strengthen cybersecurity. For example, PECO is performing upgrades to its natural gas supervisory control and data acquisition ("SCADA") system, which will transfer PECO's SCADA system to a new version with enhanced functionality and security. The SCADA upgrade also puts all of Exelon's operating companies on the same platform for additional efficiencies. PECO recently completed upgrades to its LNG plant control system to ensure continued manufacturer support and implementation of additional cybersecurity hardening. These projects increase PECO's cybersecurity defenses and ensure PECO will be able to deliver reliable gas service as the cyber threat environment changes.

13. Q. How do annual capital investments in the natural gas distribution system infrastructure relate to PECO's Long-Term Infrastructure Improvement Plan ("LTIIP")?

A. Many of the annual capital investments in this case are included in the requirements of PECO's LTIIP for 2023-2027, which the Pennsylvania Public Utility Commission ("Commission") approved on December 8, 2022. In that proceeding, the Commission reviewed and approved PECO's plans to spend an additional $987.5 million above the Company's expected baseline and facility relocation expenditures to continue PECO's accelerated replacement programs for the retirement of aging mains, services, and district regulator stations. As a result of PECO's accelerated infrastructure replacement programs as outlined in LTIIP, unplanned outages have been reduced over the course of five years by 32%, significantly improving customer reliability. Building on these efforts, PECO will further accelerate its District Regulator Station replacement program, increasing the pace from six to ten regulator station replacements annually. This enhanced investment will proactively address aging infrastructure, reduce the risk of equipment failures, and further improve system reliability and safety. Customers will benefit from fewer service interruptions, more consistent gas delivery, and a more resilient distribution system that supports long-term reliability.

Other technologies are being utilized for PECO's natural gas programs, including the use of horizontal directional drilling and vacuum excavation, which limits open trenching and reduces surface disturbance by allowing precise, non-destructive exposure of existing utilities. These methods shorten construction duration at individual locations, reduce safety risks and third-party utility damage, and result in more consistent and efficient restoration for customers.

14. Q. Please describe, in broad terms, the types of plant additions that PECO expects to place in service during the FTY and FPFTY.

A. PECO's FTY and FPFTY plant additions are itemized by functional area and by FERC account in PECO Statement No. 4, the direct testimony of Mr. Trzaska, Exhibit MJT-2, Schedule C-2, and MJT-1, Schedule C-2, for the FTY and FPFTY, respectively.

In summary, PECO's capital budget calls for overall gas distribution plant additions of approximately $392 million during the 12 months ending December 31, 2026, and $356 million during the 12 months ending December 31, 2027, including the portion allocated to gas distribution from common plant. These investments will target reliability projects and other infrastructure improvements, by replacing outmoded infrastructure as outlined in our LTIIP Program. This benefits customers with respect to leak reduction and improvements in service reliability.

IV. SYSTEM SAFETY AND RELIABILITY AND EMPLOYEE SAFETY

15. Q. How does PECO ensure the safety and reliability of its natural gas distribution system?

A. PECO manages its natural gas distribution system in a safe and responsible manner to ensure pipeline reliability while meeting or exceeding all requirements of the federal pipeline safety regulations (49 C.F.R. Part 192) and the applicable provisions of the Pennsylvania Code (Title 52, Chapter 59).

The Company's Distribution Integrity Management Program ("DIMP") provides a rigorous framework for analyzing, ranking and mitigating threats to PECO's entire distribution system. Data obtained via preventative and corrective maintenance tasks is incorporated into the DIMP, allowing PECO to assess which asset categories need threat mitigation. PECO analyzes data throughout the year for emerging threats and incorporates the analysis results and corresponding increased mitigative actions.

PECO's preventative maintenance programs are designed to identify when an asset is not operating as intended and needs either corrective maintenance or replacement. Although many of these tasks are required by federal regulations (49 C.F.R. Part 192), PECO exceeds these federal requirements to better identify emerging issues, minimize impacts to customers, and provide sufficient lead time to address an emerging issue before it becomes detrimental to safety.

16. Q. Can you provide an example of how customers benefit from PECO programs that meet or exceed federal requirements?

A. Yes. PECO's mobile leak survey intervals for outmoded mains and services, plastic and coated steel services, and transmission and OHP lines all exceed the federally required intervals for each of those categories. In addition, in 2023, the Company implemented an "In-to-Out Meter Relocation Program" where PECO moves a customer's meter that is located inside the residence to a location outside of the residence. Moving the meter to a location outside of the customer's residence allows PECO to perform more efficient meter leak surveys. Indoor leak surveys are more time- and labor-intensive than outdoor surveys, resulting in higher operational costs. By relocating meters outdoors, the Company can reduce survey complexity and duration, thereby driving overall expenses down. This program is an improvement in customer service because PECO no longer must schedule a time with the customer to conduct the leak survey inside the residence, as well as an improvement from a safety standpoint because PECO can access the meter more immediately and without waiting to coordinate entrance to the customer's residence.

With PECO's commitment to upgrade its natural gas system, older service regulators and meter bar assemblies are being replaced with updated equipment that meets current safety and engineering standards. The upgrades, all involving PECO-owned equipment, are designed to maintain proper gas pressure and reduce the risk of equipment failure. Customers benefit from these upgrades in terms of improved safety and system reliability with minimal service interruption.

Preventative maintenance also helps ensure that PECO's natural gas distribution system continues to operate safely and reliably. When emergent situations are uncovered, PECO can provide a rapid response to address the situation. If a permanent solution is not immediately available, corrective maintenance tasks make the situation safe and allow for the proper time to plan and implement a permanent solution.

17. Q. Do PECO's safety and reliability programs meet industry standards?

A. Yes. PECO's safety and reliability programs align closely with the Pipeline Safety Management System ("PSMS") recommended by the American Gas Association and the American Petroleum Institute ("API") Recommended Practice 1173. The

PSMS framework consists of ten essential elements that support safe operating principles: Leadership and Management Commitment, Stakeholder Engagement, Risk Management, Operational Controls, Incident Investigation and Lessons Learned, Safety Assurance, Management Review and Continuous Improvement, Emergency Preparedness and Response, Competence, Awareness and Training, and Documentation and Record Keeping.

Many of these elements were already in place before adopting PSMS, but PECO continues to enhance and introduce new initiatives consistent with PSMS principles. For example, PECO implemented a best-practice Management of Change system to identify and track updates to standards, practices, procedures, and significant physical or organizational changes, ensuring full stakeholder engagement throughout the process. The Company also strengthened its Public Safety Awareness Program in line with PSMS recommendations and API guidance. To improve Emergency Preparedness and Response, PECO now conducts quarterly table-top drills with operations leadership and incorporates experiential learning exercises into regional safety meetings.

In accordance with API RP 1173, PECO's PSMS program undergoes a third-party assessment every three years. These independent evaluations provide a standardized review that ensures compliance, consistency, and benchmarking against industry best practices. This process reinforces PECO's safety culture, identifies opportunities for improvement, and demonstrates a strong commitment to continuous enhancement of pipeline safety.

18. Q. Can you describe the various programs associated with PECO's long-term threat management?

A. PECO has long-term threat mitigation programs associated with natural gas services and mains. PECO has approximately 484,300 total natural gas services on its distribution system and, as of the end of 2024, all known bare steel services[1] were replaced with plastic or coated steel assets.

Out of PECO's approximate 7,350 miles of natural gas main on its system as of the end of 2025, 150 are composed of bare steel and 420 are composed of cast, ductile or wrought iron. Of those mains composed of bare steel, PECO has committed to replacing all mains that are eight inches in diameter or less by the end of 2030 while replacing all bare steel mains greater than eight inches in diameter and all cast, ductile and wrought iron mains by the end of 2035. PECO's baseline main replacement programs account for approximately 12 miles of main replacement each year. These programs are driven by field observations obtained during routine preventative maintenance, as well as feedback from corrective maintenance of specific assets.

PECO's accelerated main replacement programs are geared toward assets with a history of field indications which suggest that asset replacement will soon be necessary but where an individual asset has not been identified as needing replacement under PECO's regular maintenance programs. The accelerated main replacement programs are prioritized by a number of factors including field

[1] All known bare steel services that were identified in 2015 have been replaced and the Company is working to replace any newly identified bare steel services.

observations, asset-class DIMP scoring, customer satisfaction, third party construction, municipal coordination, and proposed paving/paving moratorium. PECO's annual plans include replacing approximately 45 miles of main under accelerated programs that, when combined with PECO's baseline programs, totals approximately 60 miles of main replacement annually.

19. Q. What recent enhancements has PECO implemented to improve the safety and reliability of its natural gas distribution operations to the benefit of its customers?

A. PECO has implemented several important initiatives and technological improvements focused on safety and reliability, all of which benefit customers. The noteworthy enhancements include: (1) post-construction quality audits for all contractors; (2) field data collection; (3) dispatch and field reporting; (4) implementation of the gas Planned Outage Notification ("PON") system; (5) increased utilization of marker balls and market pins; (6) prevention of cross-boring; (7) continued efforts to promote public awareness of potential hazards; and (8) installation of high-pressure gas mains and upgrades of natural gas plant to promote ongoing reliability. I discuss each of these initiatives in greater detail below.

(1) Post-Construction Quality Audits for all Contractors. Since 2018, the Company has conducted post-construction quality audits and random dig ups of all line of work for all PECO contractors. The post-construction quality audits are overseen by PECO personnel for new work completed in the previous 30 days. Any identified defects are repaired immediately by the contractor and at the contractor's expense. In 2024, we conducted 5,560 inspections (with 78,180 observations). In 2025, we conducted 4,713 inspections (with 65,448 observations).

(2) Field Data Collection. In 2026 PECO will add seven full time equivalent employees to improve field data collection. Maintaining accurate and up-to-date field data is critical to support safe construction and maintenance activities by reducing field uncertainty, improving hazard identification, and enabling crews to work with greater awareness of system conditions. Enhanced field data accuracy also supports compliance, improves job planning, minimizes rework, and helps mitigate risks to employees, contractors, and the public.

(3) Dispatch and Field Reporting. In 2025, PECO improved the work management system for main valve maintenance. All valves were migrated to Asset Suite 8, a program that allows PECO to manage and store all information about the valves on its system and its inspection of those valves. This project significantly improved tracking of compliance, preventative maintenance, and corrective maintenance for all of PECO's valves. Currently, PECO is developing the same system upgrade to manage and store the same information about its bridge mains, and that project will be complete in 2026. PECO Gas utilizes LocusView software to capture high-accuracy GPS locations of assets and other key data attributes through digitized forms. In 2025, we upgraded the LocusView platform to Generation 36, the newest version available. This helped streamline operational workflows, improved data quality, enhanced security, and position PECO for digital as-builts in the future.

(4) PON System. The Gas PON is a system used by PECO to notify customers of a planned outage. The Gas PON system uses a single-user interface for PON information, with consolidated outage information in one easy-to-use portal to automate the creation and distribution of timely notices to customers. The Gas PON system can also be leveraged to schedule indoor leak surveys internally, thereby helping to lower PECO's operational expenses by avoiding contractor outsourcing related to appointment scheduling. Customer benefits of Gas PONs include notifications, timely updates, proactive alerts, cancellation and rescheduling alerts, and customer friendly messaging. The communication channels include letter (US mail service used only when providing at least two weeks' prior notice of an action to take place), email, SMS, push (PECO notification cell phone application), and voice (phone call).

(5) Marker Ball and Marker Pin Utilization. PECO utilizes marker balls, which are buried alongside underground facilities, to provide an accurate, convenient and long-lasting means to identify specific locations on PECO's natural gas distribution system, including valves, dead ends, leaks, or places where the pipeline changes directions. In 2025, PECO installed approximately 30,000 marker balls on its system for use in assisting with locating of various facilities. In 2025, PECO installed approximately 1,000 marker pins to allow for increased marker installation and enhance future locating ability. Marker pins, which are an enhancement to the marker ball technology, are used when damage inspectors are confident about the location of a covered asset. The use of marker balls and marker pins benefit customers by helping crews accurately locate underground gas lines, which reduces the risk of accidental damage, improves safety, and minimizes service interruptions during excavation or maintenance.

(6) Prevention of Cross-Boring. For projects that utilize trenchless technologies, PECO has implemented improved measures to avoid incidental cross-boring with another existing utility. The Company locates and exposes all utility facilities within the boring pathway, including laterals, prior to initiating boring activity. PECO also performs a camera inspection of relevant sewer laterals before and after boring activity, as appropriate. Should any "Cross Bore Notifications" come through from Pennsylvania One Call, they will be treated as an emergency.

(7) Public Awareness. PECO continues its outreach to emergency officials by offering annual gas plant familiarization tours to police, fire, and emergency management organizations with jurisdiction in areas around its natural gas plants, and provides a reference guide for local public and state officials that covers its gas safety, reliability, and emergency response measures. PECO also continues to distribute its informational brochure on reporting odors, recognizing potential hazards and calling 811, and partners with municipalities in its natural gas service territory to make these brochures available to the public at licensing and inspection offices. In 2025, PECO's Standards and Compliance department teamed with PECO's Damage Prevention department and an external vendor to create a variety of brochures around public safety and performing work in close proximity to PECO's underground and aerial facilities. The work included the development of a website that is available to PECO customers as well as the licensed contractors that work in Southeast Pennsylvania. The team also developed and updated related safety brochures that have been customized to provide information that is relevant to each type of occupation, such as first responders, public officials and contractors.

Finally, in addition to PECO's efforts to educate existing customers and stakeholders as described above, for new alternate fuel customers that convert to natural gas, PECO has begun to distribute carbon monoxide detectors free of charge.

(8) Ongoing Reliability Project. As part of the ongoing natural gas reliability project in Delaware and Montgomery counties to meet the growing needs and demands of our customers, PECO installed 11.5 miles of high-pressure gas main and upgraded PECO's natural gas plant infrastructure in West Conshohocken. This project was delayed due to an appeal of a Commission ruling permitting PECO to utilize its proposed project location for the construction of a reliability station in Marple Township in Delaware County. The Commonwealth Court remanded the matter to the Commission for an environmental review of the placement of two buildings associated with the Marple reliability station, and hearings were held in December 2023. On April 3, 2024, an administrative law judge issued a decision again concluding that the buildings for the reliability station were necessary, and the Commission entered an opinion on September 26, 2024, in which the Commission reached the same conclusion. After another appeal to the Commonwealth Court, the Commonwealth Court affirmed the Commission's decision on February 2, 2026. The Township and intervenors have filed a petition for review of the Commonwealth Court's decision with the Supreme Court of Pennsylvania, which is expected to rule later this year on the petition.

20. Q. What other actions has PECO taken to promote system safety and reliability?

A. Between preventative maintenance activities, the accelerated investment in the replacement of potentially hazardous capital assets and the utilization of the enhancements mentioned above, PECO continues to improve its performance in both safety and reliability metrics. In addition to the bare steel services replacement I have already discussed, several key additional metrics demonstrate the extent of our success, including a reduction in incoming leaks, natural gas odor calls, and damage to its distribution system relative to One Call tickets received.

21. Q. How has PECO reduced leaks and natural gas odor calls?

A. PECO has replaced outmoded mains (i.e., cast iron and unprotected bare steel) on an accelerated basis in coordination with the Company's LTIIP and, as a result, has seen a 21% reduction in incoming leaks since 2019. While this reduction in leaks has lowered emissions, it also has decreased the number of corrective maintenance activities required to be made by PECO, which has allowed the Company to reduce costs associated with emergency repairs, including associated labor, materials and restoration costs, and truck rolls. This reduction of corrective maintenance activities and associated costs necessarily helps to lower the Company's ongoing operations and maintenance ("O&M") expenses. In addition, fewer leaks lead to higher customer satisfaction because it reduces the number of corrective maintenance activities taking place on customer properties or neighboring streets. Moreover, because of PECO's mains and services replacement programs, natural gas odor calls have decreased 36% since 2014. PECO's natural gas odor response rate has remained in the top decile among similar natural gas utilities per industry benchmarking.

22. Q. Can you please explain the actions PECO has taken to reduce the damage rate relative to One Call tickets?

A. Within the last two years, 2023 through 2025, PECO has experienced a general decline in the occurrence of damage to its natural gas distribution system relative to the number of One Call tickets received, each of which is a potential damage case. Natural gas underground damages per 1,000 requests decreased from a rate of 1.58 in 2023 to 1.50 in 2025. Similarly, the third-party damage rate decreased from 1.33 in 2023 to 1.23 in 2025 and natural gas damage due to print error (i.e., mapping error) has dropped from 113 in 2023 to 106 in 2025. These positive trends are attributed to PECO's increased focus on its damage prevention program and on PECO's Gas Mapping Program initiative.

In 2025, PECO's Damage Prevention department implemented a new ticket management system which allows PECO to improve its oversight of locating vendors and the on-time completion of One Call tickets. The ticket management system also allows PECO to be innovative with how it communicates to the contractor community regarding performance of work around our critical assets. For example, for any One Call ticket that falls within a specified boundary around PECO's regulator stations, and its natural gas and electric transmissions assets, an automatic notification is immediately sent via email to the contractor of the critical asset within the scope of their work site and a contact to reach out to PECO for any questions. Furthermore, the ticket management system has allowed automatic processing of demolition tickets to ensure a timely notification is made to the correct PECO personnel. These improvements have resulted in a decrease in the number of incidents resulting in damage to PECO's distribution system from 399 in 2024 to 349 in 2025 (-13%). Lower damage rates reduce repair and emergency response needs, lowering operating costs while also improving safety by minimizing gas leaks and public exposure to hazardous conditions.

23. Q. Are there other steps that PECO has taken to reduce damage to its gas distribution system?

A. PECO's Damage Prevention department in conjunction with its Gas Contract Controls group have created and filled four new Senior Contract Coordinator ("SCC") positions, each with the sole responsibility to oversee the location of third-party contractors and vendors on the PECO system. These SCCs will be responsible for auditing all the contractors and vendors on the system and completing a specific checklist developed by the Damage Prevention department. The Damage Prevention department also increased the amount of damage prevention inspectors in the field from six to ten over the past 18 months, which will allow a quicker response to excavators for mapping discrepancies as well as safety outreach while working around PECO's facilities. The increase in damage prevention inspectors has allowed PECO to increase our inspector oversight in each of the four counties outside the City of Philadelphia.

Finally, PECO's Damage Prevention department completed a Request for Proposal for the next locating contract, which will last from 2026 to 2029. This new contract has strict requirements for identifying, locating and marking out PECO assets.

24. Q. What is PECO's record with respect to the safety of its employees?

A. Maintaining the highest standards for workplace safety is a top priority for the Company. A critical component of safety culture involves protecting our employees from serious injuries and fatalities ("SIFs"). Serious injuries are defined by the Edison Electric Institute SIF Criteria. To that end, PECO uses energy-based safety classifications to mitigate incidents with high energy that increase the potential for SIFs. The intent is to improve the effectiveness and efficiency of hazard recognition, prioritization, and control across the organization. Utilizing our Safety Classification Learning Model, employees are able to identify high energy sources that could lead to serious injuries and put direct or limited controls in place to reduce or eliminate the exposure to the high energy hazard. A High Energy Serious Injury or Fatality is a high energy event with no direct controls utilized that resulted in an employee's serious injury or fatality. In 2026 and beyond, PECO will strive to continuously improve performance and foster a safety culture that engages the entire workforce to prevent accidents, injuries, and occupational illnesses. In 2026, PECO will distribute a new Energy Based Safety Field Guide for employees to use as an aid in identifying the high energy hazards on their jobsite. Frontline leaders are now performing energy-based observations to reinforce the Energy Based Safety mindset as well.

In addition, PECO participates in a coordinated effort with its sister utilities across Exelon through a program called Safety Best Practices. This program ensures that all Exelon operating companies leverage their diverse experiences to stay focused on performing work as safely as possible and providing consistent, high-quality support to drive safe operations across the enterprise.

For 2026, PECO Gas Operations has a target of completing five Safety Best Practices initiatives. Three initiatives continuing from 2025 include:

Roadside Safety, which aims to evaluate and implement Work Area Protection solutions beyond minimum requirements to help ensure the health and safety of employees and contractors while working in roadways.

Crew Leader Training Academy, which will be an enhanced initial training program to ensure Foremen have the safety leadership knowledge and skills to perform effectively in their roles.

SIF Leadership Prevention Guide, which is a guide that educates the leaders of today and tomorrow on Exelon's SIF Prevention Playbook to continue to advance safety as Exelon's core value.

Two new initiatives will also launch in 2026:

Confined and Enclosed Spaces, which will develop an all-utility program versus an operating company-specific program.

Job Brief Quality, which will align criteria of what is required on a job brief across Exelon.

These efforts ensure PECO continues to learn from partners across Exelon and the broader industry, strengthening our processes and further enhancing PECO safety culture.

PECO maintains a collaborative culture that listens to employee safety concerns and receives feedback through its Line-Led Teams. PECO's employee safety focus is on the following core areas: Hazard Recognition, Safe Driving, Ergonomics, and Slips/Trips/Falls. The Company's open environment affords all of its employees the opportunity to raise awareness and collaborate with PECO on innovative solutions to promote employee safety in these core areas.

25. Q. With overtime currently above the recommended 15%, what steps is PECO taking to manage this trend and how is the Company monitoring overtime hours to prevent employee fatigue?

A. PECO continually evaluates and implements measures to improve performance while maintaining the safe and reliable operation of the gas distribution system. These efforts support PECO's safety culture and ensure that, during storm events, and other emergent conditions, qualified gas personnel are available to respond promptly to protect public safety, maintain pipeline integrity, and restore gas service safely and efficiently. Overtime is used primarily to ensure compliance with pipeline safety requirements and to address unplanned response work necessary to mitigate safety risks.

In addition, overtime is actively monitored through analytics and departmental overtime Key Performance Indicators to identify trends and opportunities for improvement. In many cases, the use of overtime is more cost effective than outsourcing comparable pipeline work, resulting in lower total costs. Overtime usage is closely scrutinized and applied on an as-needed basis, with decisions guided by employee safety, workload variability and customer and community impact. PECO also manages work hours to mitigate fatigue and minimize safety risk, supporting the safe and reliable delivery of natural gas service.

V. MANUFACTURED GAS PLANT REMEDIATION PROGRAM

26. Q. Please discuss the Company's program to remediate former manufactured gas plant ("MGP") sites and its FTY and FPFTY claims for the cost of that program.

A. PECO has undertaken positive efforts to eliminate potential environmental concerns at its former MGP sites. Historically, these sites were used to manufacture gas from coal for distribution to customers for heating, cooking and lighting purposes. Following the advent of electricity, and the construction of the interstate natural gas pipeline system, MGPs became obsolete and were no longer necessary. Currently, PECO has 26 former MGP sites geographically dispersed around our service territory. To date, 20 of the 26 sites have been actively remediated to standards established by the Pennsylvania Department of Environmental Protection's ("PADEP") Land Recycling Program ("Act 2 Program").

Four of the five remaining sites are currently enrolled in the Act 2 Program and are undergoing active remediation. Once remediated, the sites will no longer pose a threat to human health or the environment and could be used for various beneficial land-use purposes that otherwise would not have been previously permitted. PECO intends to achieve regulatory closure with PADEP for 25 of the 26 identified MGP sites by the end of 2030. PECO has also been actively working on obtaining access to the remaining site, but the current property owner has indicated that it has no intention of allowing access to the site for PECO to perform site investigation to determine if remediation would be necessary to mitigate risks to human health and the environment. PECO is currently working to gain access to the remaining MGP site by requesting support from the PADEP.

Since 2011, the Company has spent, on average, $4.3 million per year for MGP remediation. The Company expects to spend approximately $23.7 million over the next ten years (2025-2034) and a total of $24.0 million through 2039 on MGP remediation with an O&M cost of approximately $100K per year to maintain environmental covenant requirements on the closed MGP sites.

VI. SECURITY AND ENVIRONMENTAL PROGRAMS

27. Q. Does the Company have a program to address cybersecurity and physical security risks?

A. In addition to the Company's IT investments, PECO has implemented an extensive defense-in-depth cybersecurity program that has cyber and physical security controls aligned to the National Institute of Standards & Technology (NIST) Cyber Security Framework (CSF) and other industry standards to identify, detect, defend, and respond to cybersecurity threats to protect PECO's critical infrastructure. These controls are certified annually. The cybersecurity plan is managed by a centralized security team, Exelon's Corporate and Information Security Services (CISS), who have 24x7 operations to monitor and respond to any potential risk to Company assets. In addition, PECO maintains compliance with directives issued by the Department of Homeland Security's Transportation Security Administration ("TSA") for its gas plant operations and is also currently undergoing a significant Operational Technology (OT) Security Controls program as a part of a multi-year effort to implement a consistent set of security practices across our OT and supporting networks for the Exelon utilities.

In accordance with this program, we properly identify and categorize OT assets and are developing an associated inventory of OT assets currently on our systems. The Company has implemented procedures to identify and mitigate specific cyber threat vulnerabilities to our OT assets and has implemented security measures to protect our systems from external threats via third-party connections. Our natural gas operations are also subject to the cybersecurity directives issued by the TSA. New security control programs have been developed to ensure compliance with TSA's requirements, and our efforts have been successful. In 2023, TSA inspected PECO's implementation of TSA's directives and concluded that PECO was in compliance with the new requirements, with four "smart security practices" cited for specific recognition.

The ever-evolving threat landscape is of concern to our entire industry. In response, PECO has also made significant investments in physical security as part of two separate programs. In 2015, PECO initiated the Facility Enhancement Program ("FEP") to enhance the physical security for operationally critical electric and gas assets. For natural gas, this includes critical system valves, gate stations, the LNG and propane plants, and the control rooms. Additionally, in 2020, PECO began its Office and Support Facilities ("O&SF") program to enhance the physical security at offices and operation service centers. Both FEP and the O&SF program were designed to reduce unauthorized access to personnel, equipment, systems, and materials utilizing an in-depth defense strategy. Both programs use a risk-based approach and tiering methodologies that analyze the criticality of each type of asset

(Electric, Gas, and O&SF) to prioritize investment. PECO tiers our assets based on factors such as, but not limited to, system impact, customer count, critical customers served, and feeder number. While the tier dictates the protections implemented at each site, the protections are designed for the threats within the service territory that PECO operates.

28. Q. Ms. Angus, please describe PECO's energy efficiency and environmental efforts regarding its own land, buildings, and emissions.

A. PECO's commitment to energy efficiency and environmental stewardship is also integrated in the Company's daily operations. PECO has established an environmental management system based on standards set forth in International Organization for Standardization 14001, which supports the development of performance-improvement goals and targets. Exelon, PECO's parent company, was recognized for its sustainability leadership for the 19th consecutive year and has been named to the Dow Jones Sustainability North America Index for its carbon reduction efforts, investments in innovative technology, and local philanthropy. With respect to land quality, PECO has obtained Conservation Certification from the Wildlife Habitat Council, powered by Tandem Global, the National Wildlife Federation and the North American Pollinator Partnership Campaign for 20 sites (166 acres).

PECO is also focused on being a low-carbon company. From 2015-2025, PECO reduced its greenhouse gas emissions by approximately 59% through infrastructure investments such as the replacement of first-generation sulfur hexafluoride (SF6)-filled electrical breakers and replacement of cast iron/bare steel gas piping. PECO's greenhouse gas reduction program is in alignment with the 2018 Pennsylvania Climate Action Plan goal of a 26% reduction in greenhouse gas emissions by 2025. The Company has achieved this goal, and as of 2025, PECO has reduced its greenhouse gas emissions by approximately 50% from 2018. PECO is looking to exceed this goal with our 2030 Path to Clean initiative that aims to reduce Exelon's operational emissions by 50% from 2015 levels by 2030. The Path to Clean initiatives include the modernization of gas infrastructure via pipe replacements, the implementation of programs to reduce SF6 leaks in electrical equipment and the piloting of SF6 alternatives in electrical equipment, continued focus on energy efficiency/conservation in buildings/facilities and the electrification of vehicles to reduce fuel consumption. The Company's investments in natural gas infrastructure and technologies to reduce distribution system leaks are critical to achieving this goal. In addition, we have now implemented a new technology known as ZEVAC (for Zero Emissions Vacuum and Compression). Typically, when a natural gas distribution utility replaces an outmoded main, residual gas is released into the atmosphere. Through ZEVAC, PECO teams can vacuum the residual gas from the outmoded main and inject it directly into an active main and thereby reduce related emissions by nearly 100%.

PECO also continues to maintain one of the largest urban green roofs in Pennsylvania (approximately one acre), that was built on an existing building at its headquarters in Philadelphia, which was recently certified by Pollinator Partnership as an important pollinator habitat. Waste recycling also continues to be a focus at PECO, with recycling increasing from 94% (2016) to 98% (2025).

29. Q. Please describe the Company's efforts to support the use of alternative fuel vehicles and related technologies.

A. PECO operates its own fleet of 1,522 hybrid, electric, flex fuel, and biodiesel vehicles including 69 plug-in hybrid trucks, 62 battery electric vehicles, and 160 Job Energy Management system worksite electrification plug-in aerial trucks. PECO continues to utilize telematics technology to drive performance and efficiencies. The Company also encourages sustainable practices with employees by providing over 127 EV charging stations, rebate programs, and bike racks at most Company locations.

VII. CONCLUSION

30. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060860**
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Chantee C. Angus, hereby state that I am a Vice President of Gas Operations for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 2 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Dated: March 30, 2026

Chantee C. Angus

PECO Statement No. 3:
Direct Testimony of Marissa E. Humphrey

PECO ENERGY COMPANY
STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2026-3060860

DIRECT TESTIMONY

WITNESS: MARISSA HUMPHREY

SUBJECT: EFFORTS TO CONTROL CUSTOMER COSTS AND MITIGATE IMPACTS TO CUSTOMER BILLS; OVERVIEW OF PECO'S ACCOUNTING EXHIBITS AND BUDGETING PROCESS; EXELON BUSINESS SERVICES COMPANY; AND THE CORPORATE ALTERNATIVE MINIMUM TAX

DATED: MARCH 30, 2026

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DIRECT TESTIMONY
OF
MARISSA HUMPHREY

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Marissa Humphrey. My business address is 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as Senior Vice President, Chief Financial Officer and Treasurer. In that capacity, I am responsible for PECO's financial function, including budgeting, long-range financial planning, financial analysis and reporting, project evaluation, and financings. In addition, I have oversight and coordination responsibilities for PECO's accounting, tax, treasury, investor relations, and risk management activities, and I monitor the Company's financial performance to ensure that PECO complies with its financial internal controls and management discipline.

3. Q. Please briefly describe your educational background and professional experience.

A. I hold a Bachelor of Arts degree in Biology from Brown University and a Master of Business Administration from Duke University Fuqua School of Business. I joined Constellation Energy in 2007, working in Corporate Finance, and have advanced through a number of positions at Constellation, Baltimore Gas & Electric ("BGE"), Exelon Business Services Company ("EBSC"), Pepco Holdings ("PHI"), and PECO. Prior to and following the 2012 merger of Exelon and Constellation, I was named Director of Financial Planning & Analysis ("FP&A") at BGE. Beginning in 2014, I served as the Exelon Project Management Officer for the Exelon/PHI merger and, upon the closure of that merger in 2016, I was promoted to Vice President of PHI FP&A. After three years, I transitioned to Vice President of the Exelon Utilities Finance team, and in 2020 I was named Vice President of Regulatory Policy & Strategy at PHI. In 2022, I was promoted to Senior Vice President, Chief Financial Officer and Treasurer of PECO. Prior to joining Constellation Energy, I worked for several years in consulting and healthcare finance.

4. Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to: (1) summarize PECO's continued efforts to control customer costs and reduce customer bills; (2) provide an overview of PECO's principal accounting exhibits and its budgeting process; (3) describe the nature and allocation of costs for services that PECO receives from EBSC; and (4) discuss the Corporate Alternative Minimum Tax ("CAMT").

II. PECO'S EFFORTS TO CONTROL CUSTOMER COSTS AND MITIGATE IMPACTS TO CUSTOMER BILLS

5. Q. Please describe PECO's efforts to control customer costs and mitigate impacts to customer bills.

A. PECO works to minimize financial impacts on customers in two ways. First, PECO diligently manages its own expenses to minimize costs for which customers will ultimately be responsible. Second, PECO supports programs and investments to help customers reduce their overall energy usage and costs, including a number of low-income-focused programs to better support the Company's most vulnerable customers. For example, in 2025, PECO launched its Customer Relief Fund, which is designed to provide immediate bill assistance to limited and moderate-income households experiencing rising energy costs. PECO's customer programs are discussed further in the direct testimony of Brendan J. Taylor (PECO Statement No. 1), Jacqueline Golden (PECO Statement No. 12), and Clifton Krausz (PECO Statement No. 13).

6. Q. Have these efforts negatively impacted PECO's service to customers?

A. Absolutely not. While PECO has undertaken efforts to control customer costs, it has done so in a manner to maintain the same level of safe and reliable service our customers expect and, where possible, improve such service.

7. Q. What are some examples of PECO's efforts to control its costs?

A. The Company works proactively to identify initiatives to further improve productivity through best practices across the organization, leverage new technologies and equipment to reduce costly repairs on aging infrastructure, and deliver other operational efficiencies. Company witness Chantee Angus (PECO Statement No. 2) discusses the Company's efficiency efforts in greater detail. Recent examples of these initiatives include:

- Relocating meters from inside to outside of customer residences to drive more efficient meter leak surveys. Indoor leak surveys are more time- and labor-intensive than outdoor surveys, resulting in higher operational costs. By relocating meters outdoors, the Company can reduce survey complexity and duration, thereby driving overall expenses down.

- Implementing a Gas Planned Outage Notification ("PON") System to enhance safety and reliability and reduce costs. The PON System allows PECO to automatically notify customers of planned outages, which eliminates the need for contracting resources to manually make appointments with customers for leak surveys.

As described in Section III of my testimony, PECO also actively manages the creation and execution of its budget, taking reasonable and prudent steps to minimize its operations & maintenance ("O&M") expenses and mitigate inflationary impacts on its customers. Additionally, PECO takes steps to minimize its financing costs and utilizes the EBSC to improve efficiencies and lower its costs.

8. Q. Please describe the overall results of PECO's efforts to control its O&M expenditures since the Company's last base rate case.

A. PECO projects that its 2027 O&M expenses, excluding pension and bad debt expense (which are variable year to year and largely outside of the Company's control), will decrease from the end of 2025 at an annual rate of 1.3% compared against the 2.6% projected average inflation rate for 2026-2027 (2.9% in 2026 and 2.4% in 2027).[1] While PECO is still making focused system improvements on behalf of customers as described in Ms. Angus' testimony, the Company's ongoing initiatives to increase efficiency and minimize costs to its gas business have resulted in savings for customers.

[1] S&P Global Dec. 2025, Consumer Price Index (CPI) Philadelphia-Wilmington-Atlantic City-PA-NJ-DE-MD Area.

9. Q. Has the Company been impacted by the current high inflationary environment?

A. Yes. The Company has continued to experience inflationary pressure, which has contributed to increases in the Company's labor costs, material prices, contracting rates, and borrowing costs. This is expected to continue, with inflation projected to average 2.6% over 2026-2027 (2.9% in 2026 and 2.4% in 2027). However, the Company has successfully managed to keep its O&M expense growth, excluding bad debt and pension expense, well below the rate of inflation.

10. Q. Why is it important for PECO to maintain its investment-grade credit rating and minimize its borrowing costs?

A. Maintaining PECO's investment grade credit ratings is important to reducing customer costs. PECO projects that it will need to invest approximately $791 million in gas distribution plant between January 1, 2026 and December 31, 2027. A meaningful portion of these planned investments will be financed with debt and other forms of capital. The Company's credit ratings will impact the cost it will need to pay to attract such capital, and ultimately such costs will be borne by PECO's gas customers. For example, continuing to maintain a strong credit rating will help PECO control its credit spreads, which in turn will help control the all-in cost of long-term debt financing. Therefore, it is important that the Company maintain its favorable credit metrics in order to minimize customer costs.

11. Q. Please describe how inflationary pressures have impacted the Company's borrowing costs.

A. Sustained inflationary pressure has contributed to elevated interest rates, which have directly increased the Company's borrowing costs. As noted earlier, this is expected to continue. The average 30 Year Treasury rate, which serves as a risk-free benchmark rate in many financial products, including thirty-year maturity bonds that are typically issued by utility companies, demonstrates this sustained inflationary pressure. The 30 Year Treasury yield has remained high in recent years due to continued inflationary pressures, with the average rate increasing 20% since 2023.[2]

As a result, it is more expensive for the Company to finance its ongoing operations and capital investments, a portion of which are funded through debt, consistent with the Company's Pennsylvania Public Utility Commission ("Commission")-approved capital structure. Interest rate increases pushed up the Company's average cost of borrowing from 4.58% in 2025, as forecasted in the Company's prior gas rate case filing, to 4.78% in 2027, as forecasted in the Company's current gas rate case filing. The Company's cost of debt is further detailed in the testimony of Company witness Michael J. Trzaska (PECO Statement No. 4) and in PECO Exhibit MJT-1, Schedule B-6.

12. Q. Notwithstanding the current high inflationary environment, how has PECO minimized its borrowing costs?

A. PECO works closely with its banking partners to understand market conditions at the time of issuance of debt to determine what tenor and timing will ultimately generate the most investor demand, thereby securing a lower interest cost for the benefit of customers. In September 2025, PECO successfully priced a two tranche

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[2] *See* Daily Treasury Rates, U.S. Department of the Treasury, https://home.treasury.gov/resource-center/data-chart-center/interest-rates/TextView?type=daily_treasury_bill_rates&field_tdr_date_value=2026.

first mortgage bond ("FMB") issuance totaling $1.05 billion. The first tranche was a $525,000,000, ten-year FMB offering at a spread of 68 basis points over the ten-year U.S. Treasury for an all-in coupon rate of 4.875%. The second tranche was a $525,000,000 thirty-year FMB offering at a spread of 75 basis points over the thirty-year U.S. Treasury for an all-in coupon rate of 5.650%. The deal was well-received by investors. The strength of PECO's name and credit profile – PECO maintains an investment-grade credit rating – continues to drive strong investor demand, permitting PECO to tighten the credit spread from the initial launch. The transactions resulted in the second and third lowest utility transaction credit spreads (68 and 75 basis points, respectively) in 2025 at the time of issuance. Moreover, PECO's thirty-year tranche with a 75 basis point credit spread ties for the tightest thirty-year new issue spread for the Company since 2009. Additionally, instead of issuing all thirty-year bonds in 2025, the Company opted for a split of ten-year and thirty-year bonds to reduce the overall interest expense borne by customers while being prudent about managing the Company's debt maturity profile.

III. OVERVIEW OF PECO'S PRINCIPAL ACCOUNTING EXHIBITS AND BUDGETING PROCESS

13. Q. Please provide an overview of PECO's principal accounting exhibits.

A. PECO's principal accounting exhibits are Exhibits MJT-1, MJT-2, and MJT-3, which represent PECO's revenue requirement for the FPFTY, future test year ("FTY"), and historical test year ("HTY"), respectively, and are sponsored by Mr. Trzaska (PECO Statement No. 4). Exhibit MJT-1 includes PECO's claimed measures of value (i.e., rate base), basic accounting data, a detailed development of the major components of the Company's rate base claim, detailed adjustments required to place FPFTY revenues and expenses on a ratemaking basis, and a discussion of FTY and HTY data. As explained by Mr. Trzaska, Exhibits MJT-2 and MJT-3 follow a similar format, and each of the three exhibits is based, in part, upon data provided by other PECO witnesses.

14. Q. Please describe PECO's budgeting process.

A. One of the key goals of the annual planning process is to integrate and align PECO's operational, regulatory, and financial plans. The operational plan includes goals focused on achieving at least top quartile safety performance, reliability, and customer satisfaction. The operational plan is also consistent with statutory and Commission-imposed regulatory requirements. The Company sets spending targets in its financial plan to achieve its operational goals and comply with such regulatory requirements. As I explained earlier, the Company attempts to minimize its O&M expenses to the extent possible and has generally been successful in controlling these expenses at a lower compound annual growth rate than the rate of inflation.

The planning process starts with a review and update of PECO's operational and regulatory goals and initiatives to determine if changes are required for the future. Any significant changes in such goals and initiatives are taken into consideration when updating the Company's Long Range Plan ("LRP"). The LRP consists of a five-year outlook and is updated with key assumptions (e.g., inflation rates, interest rates) and with detailed input provided by "responsibility areas" (e.g., Gas Operations and Customer Operations). Each responsibility area reviews its historic expense levels, current and anticipated employee staffing levels, performance assessments, regulatory requirements, operational goals, specific projects, and other factors and develops a responsibility area-specific LRP. The individual responsibility area LRPs are typically submitted for review by each department in June of each year and are carefully analyzed for consistency, completeness, and appropriateness. The responsibility area LRPs are then consolidated into a single LRP and delivered to PECO's senior management (i.e., the Chief Executive Officer, Chief Operating Officer, and Chief Financial Officer) for review and approval in September.

Once that LRP has been updated and approved, its data is thoroughly scrutinized to formulate a detailed two-year budget. The two-year budget is developed by responsibility area, similar to the LRP process described above. The Company then develops its financing plan to ensure that PECO can maintain investment-grade credit ratings. Based on that plan, PECO determines the amount it can borrow to fund its spending plans and the dividend levels that will achieve its targeted capital structure. The consolidated budget is then submitted to PECO senior management for review and approval. The PECO board reviews and approves the Company's capital, O&M, dividend, and financing plan annually.

15. Q. Is that the end of the process?

A. No. Although the budget, as approved, remains in place throughout the year and is not formally amended, it is reviewed and updated on a monthly basis to reflect estimates derived from the Company's latest data. Actual results are then compared to both the original budget and the latest estimates. Any significant variances are thoroughly investigated to determine why the Company's actuals have departed from its estimated budget and actions are taken as appropriate.

16. Q. Do the personnel in each of the responsibility areas develop their budgets by Federal Energy Regulatory Commission ("FERC") account?

A. No, the responsibility areas do not budget by FERC account. Rather, the responsibility area budgets are prepared on the basis of business activities (i.e., GAAP[3] basis) and related cost elements such as payroll, employee benefits, outside services, etc.

17. Q. Has PECO's budgeting process been reviewed by the Commission?

A. Yes. PECO's budgeting process was reviewed by the Commission during its Focused Management and Operations Audit of PECO in 2022 ("2022 Audit").[4] The Commission's auditors found no deficiencies or weaknesses in the way PECO prepares its budgets.

18. Q. Mr. Trzaska presents the budgeted data for the twelve months ending December 31, 2027 on a FERC account basis in Schedules B-2, B-3, and B-4 of Exhibit MJT-1. How were those figures derived?

A. As Mr. Trzaska explains more fully in his testimony, he analyzed PECO's recorded FERC account balances for the twelve months ending December 31, 2025 to determine their composition (e.g., payroll, benefits, rent) and then distributed the FPFTY budgeted costs to the appropriate FERC account based on his findings. The

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[3] "GAAP" stands for "generally accepted accounting principles."

[4] *See* Focused Management and Operations Audit of PECO Energy Company, Docket No. D-2021-3023906 (issued July 2022).

results of Mr. Trzaska's proposed distribution of costs were then reviewed and confirmed with members of my staff.

19. Q. Do Exhibits MJT-1, MJT-2, and MJT-3 contain all of the data needed to evaluate PECO's claimed revenue requirement?

A. No. While MJT-1, MJT-2, and MJT-3 present, in considerable detail, the Company's rate base, revenue, expense, and tax claims, much of the supporting data is provided in the separately bound volumes comprising the Company's responses to the Commission's rate case filing requirements at 52 Pa. Code §§ 53.52, 53.53, 53.62, 53.64, and 56.56 and supplemental data requests issued by the Commission's staff. I note that, consistent with the approach to develop responsibility area budgets on the basis of business activities (GAAP basis) as described above, many of the Company's responses to the filing requirements and supplemental data requests that accompany this rate filing were prepared on the basis of business activities (GAAP basis). As a result, there may be differences between those responses and figures in MJT-1, MJT-2, and MJT-3, which were prepared on a FERC account basis.

20. Q. How does the Company's approach to determining plant additions for rate base reflected in Mr. Trzaska's testimony differ from the capital budgeting process you describe above?

A. With respect to capital budgeting, the Company accounts for capital expenditures in the period when such expenditures are made. The Company determines plant additions based upon when plant is expected to be placed into service. This can, and often does, differ from the period in which capital spending occurs. In determining plant additions for rate base, PECO included only the plant that it expects will actually be placed in service by the end of the FPFTY. I note, however, that the larger projects with which that plant is associated for PECO's budgeting purposes may show an overall project completion date that is beyond the end of the FPFTY, as components of a project may extend beyond the FPFTY.

21. Q. How do PECO's 2025 actual expenses and rate base additions compare to its projections in its 2024 case?

A. The Company's 2025 actual capital additions were greater than its projections in the 2024 gas base rate proceeding, and are detailed in the report that was provided on March 19, 2026 to the Commission's Bureau of Technical Utility Services, the Bureau of Investigation and Enforcement, the Office of Consumer Advocate, and the Office of Small Business Advocate.

With respect to 2025 O&M expense, PECO's actual expenditures were approximately $4.0 million higher than projected in the Company's 2024 base rate case, and when adjusted for bad debt and pension expense (which are predominantly beyond the Company's control), PECO's 2025 actual O&M expense was equivalent to the $163 million projected in the Company's 2024 base rate case.

IV. EXELON BUSINESS SERVICES COMPANY

22. Q. Does PECO procure certain shared services from an affiliated service company?

A. Yes. Like many other energy holding company enterprises, Exelon created a service company, the EBSC, following the merger of PECO and the former Unicom Corporation, to house specific support functions that it believed could be staffed more efficiently and economically on a centralized basis.

23. Q. What types of services does the EBSC make available and to whom?

A. The EBSC is designed to provide a range of what would typically be regarded as in-house services in the case of a stand-alone utility. In broad terms, those services fall into the following categories: IT; supply; finance; commercial operations; human resources; government and regulatory affairs and public policy; legal and corporate governance; utility operations; real estate; executive services; communications; and security. The EBSC offers its services to PECO and other affiliated members of the Exelon family of utility companies, which include Atlantic City Electric Company, Baltimore Gas and Electric Company, Commonwealth Edison Company, Delmarva Power & Light Company, and Potomac Electric Power Company.

24. Q. Is PECO required to utilize the EBSC's services?

A. No, PECO is not required to use the EBSC's services. Under the terms of the General Services Agreement ("GSA") between PECO and the EBSC, which was approved in the PECO/Unicom merger proceeding at Docket No. A-110550F0147, PECO has the discretion to determine whether and to what extent to utilize the EBSC's services in all areas except corporate governance.

25. Q. What role does the EBSC play in PECO's natural gas distribution operations?

A. PECO's overall approach is to use its own personnel or independent contractors to staff the day-to-day operations of its natural gas delivery system, as well as its customer-service functions (e.g., call center and billing services). Other services, such as employee benefits administration, mass purchasing, insurance, and treasury, to name a few, are provided by the EBSC. Certain highly specialized services, for which it would not be cost effective to maintain the required expertise at either PECO or the EBSC, are obtained through contracting with outside firms.

26. Q. What is the principal advantage of the service company structure?

A. The EBSC enables PECO to realize economies of scale and scope that, in my judgment, could be very difficult to achieve on an individual-company basis. Indeed, if PECO were to try to maintain a full complement of comparably qualified personnel on its own payroll, the total cost PECO would incur to obtain the same level and quality of service it receives from the EBSC likely would be considerably higher.

27. Q. How does the EBSC price the services it provides to PECO?

A. The GSA provides that the services furnished by the EBSC to PECO are to be billed at the EBSC's cost. Prior to the enactment of the Energy Policy Act of 2005, the Exelon utility companies were subject to the affiliate-transaction and cost-allocation rules prescribed by the United States Securities and Exchange Commission ("SEC") under the Public Utility Holding Company Act of 1935 ("PUHCA"), which generally mandated that service companies, such as the EBSC, offer their services to affiliates at fully distributed cost. The "at cost" rules were incorporated into the GSA, and their continued use in the provision of non-power goods and services has been approved by the FERC, which assumed some of the SEC's oversight responsibilities when PUHCA was repealed, in part, several years ago.

28. Q. How is the cost of services provided to PECO determined?

A. Direct charges are made for services where possible. Otherwise, costs are allocated on the basis of the allocation factors/methodologies identified in the GSA, which were previously reviewed and approved by the SEC. These allocations and methodologies were also reviewed as part of the Commission's 2022 Audit, and the Commission's auditors found no issues with respect to PECO's cost allocation methodology.

29. Q. How does PECO satisfy itself that the services it procures from the EBSC are provided at a competitive price?

A. PECO takes several steps to ensure that the services it procures from the EBSC are provided at a competitive price. First, PECO and the management of EBSC work together to identify PECO's needs and to define service priorities and major new initiatives. As a consequence, PECO has meaningful input into the development of the EBSC's budget for the upcoming year, and I, as PECO's Chief Financial Officer, ultimately approve the service level arrangements ("SLAs"). SLAs are annual agreements between the EBSC and Exelon's operating companies (including PECO) entered into under the express authority of the Commission-approved GSA that detail the specific services that the EBSC will provide during the following year, including the scope of services, unit cost expectations, and performance measures. Services are grouped by function so that budgeted and actual costs can be tracked.

Second, the EBSC's monthly billings are carefully scrutinized by PECO personnel. Variances between actual and budgeted charges are reviewed by PECO personnel with their EBSC counterparts to ensure that all costs are properly justified.

In addition, for functions that are not already outsourced, PECO obtains extensive information regarding the composition of the EBSC's costs, which PECO can then periodically review for reasonableness. PECO's review process, which was developed in conjunction with the Commission's management auditors, along with allocation factors and methodologies used for EBSC costs, was reviewed as part of the Commission's audits of the Company in 2014 and 2022. In 2017, the Commission conducted a Management Efficiency Investigation to evaluate PECO's implementation of recommendations from the 2014 Audit.[5] The Commission again examined PECO's affiliated interest and cost allocations processes and concluded that PECO (and EBSC) had taken steps to verify that "shared services are being provided in an efficient and cost-effective manner and/or improvement opportunities are identified to ensure service offerings are fair and reasonable." PECO has also worked to implement recommendations made by the Commission, including those related to its payroll and accounts payable systems and the sharing of benchmarking reviews among EBSC, PECO, and other Exelon companies.

30. Q. What is PECO's claim in this proceeding for EBSC services?

A. PECO has included $36.2 million in its FPFTY expense claim for charges from EBSC. A breakdown of those costs is attached as PECO Exhibit MEH-1.

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[5] *See* PECO Energy Company Management Efficiency Investigation Evaluating the Implementation of Selected Management Audit Recommendations from the 2014 Focused Management and Operations Audit, Docket No. D-2016-2562303 (Aug. 2017).

V. CORPORATE ALTERNATIVE MINIMUM TAX

31. Q. How did the enactment of the Inflation Reduction Act ("IRA") impact PECO?

A. The IRA implemented a new CAMT beginning in 2023 that imposes a 15% tax on adjusted financial statement income on "applicable corporations." Applicable corporations, including Exelon and its subsidiaries, now pay the greater of 15% of their adjusted financial statement income or their regular federal tax liability. Beginning in 2023, based on available tax guidance, Exelon and its subsidiaries, including PECO, were each subject to CAMT.

32. Q. For CAMT purposes, how was the adjusted financial statement income determined?

A. The starting point for calculating adjusted financial statement income is GAAP financial statement net income. Pursuant to the federal tax statute,[6] GAAP financial statement net income is adjusted for federal income taxes, accelerated tax depreciation, pension and other postemployment benefits.[7]

33. Q. How does PECO calculate the CAMT?

A. PECO calculates the CAMT based on its standalone separate company books and records.

34. Q: Why did PECO's CAMT exceed its regular tax liability?

A. Certain expenditures that qualify for accelerated tax deductions in the calculation of a corporation's regular tax liability, such as tax repairs and certain overhead costs, are required to be capitalized for financial statement purposes. Prior to the issuance of new guidance by the U.S. Department of Treasury and the Internal

[6] 26 U.S.C. § 56A.
[7] These adjustments ensure the same treatment of these items for CAMT and regular tax purposes.

Revenue Service ("IRS") discussed later in my testimony, these expenditures were required to be capitalized and depreciated for purposes of calculating CAMT rather than immediately deducted. As a result, PECO's regular tax liability has been lower than its CAMT liability.

35. Q. How is the Company accounting for the CAMT in its financial statements?

A. For income tax accounting purposes, a current income tax liability and current income tax expense will be recorded for the CAMT liability but will be equally offset by recording a deferred tax asset and a reduction to deferred income tax expense to reflect the CAMT credit carryforward. As a result, there is no net incremental income tax expense associated with the CAMT. Corporations are entitled to a CAMT tax credit equal to the amount by which the CAMT liability exceeds the regular tax liability. This amount may not be carried back to prior years, but can be carried forward indefinitely and used in future years when the regular tax liability exceeds the CAMT liability. For income tax accounting purposes, a deferred tax asset is established for the CAMT credit carryforward.

36. Q. What is the ratemaking impact associated with CAMT?

A. PECO includes the deferred tax asset associated with the CAMT credit carryforward as an increase to rate base.

37. Q: Why is it appropriate to include the deferred tax asset related to CAMT in rate base?

A. Accelerated tax deductions related to utility property generate cash tax benefits that reduce the cost of capital. For ratemaking purposes, rate base is adjusted downward to reflect the lower cost of capital attributable to accelerated tax deductions. The

CAMT has the opposite effect; it reduces the realization of the tax benefits associated with accelerated tax deductions, such as tax repairs and certain other overhead capitalization adjustments that are not deductible in the calculation of CAMT. The Accumulated Deferred Income Taxes ("ADIT") associated with tax repairs and other property-related tax adjustments are included in PECO's rate base as a downward adjustment. Therefore, to reflect the appropriate cost of capital, the deferred tax asset associated with the CAMT credit carryforward should likewise be included in rate base as an adjustment that offsets ADIT.

38. Q. Was the ratemaking impact for CAMT contested in the Company's prior rate case?

A. No. The inclusion of PECO's CAMT credit carryforward as an increase to rate base was an uncontested issue in Docket No. R-2024-3046931.

39. Q. Has the U.S. Department of Treasury and the IRS issued any new CAMT guidelines that impact PECO?

A. Yes. On February 18, 2026, the U.S. Department of Treasury and the IRS issued Notice 2026-7. The newly issued guidance permits regulated utilities a repair deduction equal to the one claimed for regular tax purposes in the calculation of the CAMT. This will allow PECO to reduce its CAMT liability and the corresponding deferred tax asset related to CAMT credits carryforwards, which will result in a reduction to rate base.

40. Q. How does this new CAMT guidance benefit customers and underscore the Company's commitment to advocating for its customers?

A. Under CAMT, corporate taxpayers are permitted to deduct accelerated tax depreciation in the determination of the CAMT. However, prior to the issuance of Notice 2026-7, corporate taxpayers were not permitted to deduct tax repairs that were capitalized for financial accounting purposes to determine the CAMT. This had a disproportionate impact on capital-intensive companies with aging assets and resulted in utilities being significantly and disproportionately impacted by the CAMT. These CAMT impacts would have compounded in perpetuity resulting in significant and permanent annual increases in customer bills.

Since the imposition of CAMT, Exelon has worked to educate the U.S. Department of Treasury and other policymakers on the importance of permitting a tax repairs deduction for regulated utilities equal to the one claimed for regular tax purposes in the calculation of the CAMT through the submission of comments in an IRS proceeding regarding CAMT implementation.[8] We believe that these efforts contributed to the U.S. Department of Treasury issuing Notice 2026-7 permitting a tax repairs deduction for CAMT purposes.

The repairs deduction reduces PECO's CAMT liability, and the corresponding deferred tax asset related to the CAMT credit carryforwards reduces PECO's rate base, resulting in a lower revenue requirement and providing a direct benefit to customers. The reduction in PECO's CAMT liability also improves financial credit metrics resulting in lower borrowing costs and increases the availability of capital needed for investments in critical gas infrastructure.

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[8] *See* Comments of Exelon Corporation (Nov. 25, 2024), available at https://www.regulations.gov/comment/IRS-2024-0046-0008.

VI. CONCLUSION

41. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2026-3060860**
	:	
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Marissa Humphrey, hereby state that I am a Senior Vice President, Chief Financial Officer and Treasurer for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 3 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Mari Hu

Dated: March 30, 2026 — Marissa Humphrey

PECO Exhibit MEH-1:
BSC Operations and Maintenance Costs

PECO Energy Co. **PECO Exhibit MEH-1**
BSC Operations & Maintenance Costs
Presentation Basis: PECO Gas

($ in millions)

		2027 Budget
1	Legal Governance	1.8
2	Executive Services	2.1
3	Security	0.5
4	Government and Regulatory Affairs & Public Policy	0.4
5	Exelon Utility Operations	2.5
6	Communications	1.0
7	Finance	5.0
8	Human Resources	1.5
9	Real Estate	0.1
10	Supply Services	0.3
11	**Subtotal of Non-IT EBSC**	**15.2**
12	**IT EBSC**	**21.0**
13	**Total EBSC Charges**	**36.2**

Note: non-recoverable costs, including charitable contributions and lobbying costs, have been removed from the schedules above

PECO Statement No. 4:
Direct Testimony of Michael J. Trzaska

PECO ENERGY COMPANY
STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2026-3060860

DIRECT TESTIMONY

WITNESS: MICHAEL J. TRZASKA

SUBJECT: PRESENTING PECO'S OVERALL REVENUE REQUIREMENT AND CERTAIN RATEMAKING ADJUSTMENTS

DATED: March 30, 2026

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DIRECT TESTIMONY
OF
MICHAEL J. TRZASKA

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is Michael J. Trzaska. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by PECO Energy Company ("PECO" or the "Company") as a Principal Regulatory and Rate Specialist in the Regulatory Policy and Strategy Department. My duties and responsibilities in that capacity include performing financial analysis, project management and regulatory strategy for gas and electric operations throughout the Company's service territory. I am responsible for providing expert testimony on behalf of the Company with respect to various regulatory issues.

3. Q. Please describe your educational background.

A. I received a Bachelor of Science degree in Accounting from Drexel University in 1987 and a Master of Science in Finance degree from LaSalle University in 1996.

4. Q. Please describe your work experience in the energy industry.

A. Upon graduation from Drexel University in 1987, I was hired by PECO and have been with the Company since that time in various positions of increasing responsibility.

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

A. The principal purpose of my direct testimony is to explain the preparation and presentation of data supporting PECO's request for a general base rate increase for its natural gas operations. More specifically, I explain how the components of the Company's overall revenue requirement were developed. This includes certain portions of the claimed measures of value and the pro forma ratemaking adjustments that were made to calculate the Company's revenue requirement based on data for a fully projected future test year ending December 31, 2027 ("FPFTY"), a future test year ending December 31, 2026 ("FTY"), and a historic test year ended December 31, 2025 ("HTY"). For purposes of supporting PECO's proposed increase in base rate distribution operating revenue under its proposed rates, the Company is relying principally upon data for the FPFTY.

6. Q. Are you sponsoring all or portions of any exhibits in this proceeding?

A. Yes. I am sponsoring PECO Exhibits MJT-1, MJT-2, and MJT-3. PECO Exhibits MJT-1, MJT-2 and MJT-3 comprise PECO's principal accounting exhibits for the FPFTY, the FTY and the HTY, respectively.[1] The base data for the FPFTY that I used to develop PECO Exhibit MJT-1 were derived, for the most part, from PECO's capital and operating budgets for the 12 months ending December 31, 2027, while the corresponding data for the FTY used to develop PECO Exhibit MJT-2 were derived from PECO's capital and operating budgets for the 12 months ending December 31, 2026. The data for the HTY used to develop PECO Exhibit MJT-3

[1] PECO Exhibits MJT-1, MJT-2 and MJT-3 each contain multiple schedules and each page of the exhibit is numbered on a continuous sequential basis. Specific schedule pages will be cited to using the applicable exhibit pagination. For example, the second page of Schedule B-1, which is the third page of Exhibit MJT-1, will be cited as "Exhibit MJT-1, Schedule B-1, page 3."

are the data actually recorded in PECO's books of account for the 12 months ended December 31, 2025. In addition to sponsoring the exhibits described above, I am responsible for responses to certain Pennsylvania Public Utility Commission ("Commission") standard data filing requirements.

7. Q. Will you discuss separately PECO Exhibit MJT-1, PECO Exhibit MJT-2 and PECO Exhibit MJT-3?

A. Yes, I will. However, because PECO is basing its proposed rate increase on the adjusted FPFTY data, most of my direct testimony is devoted to explaining PECO Exhibit MJT-1. My testimony regarding PECO Exhibits MJT-2 and MJT-3, which are essentially identical in format to PECO Exhibit MJT-1, will briefly address the pro forma adjustments that were made to budget data for the 12 months ending December 31, 2026 and historic actual data for the 12 months ended December 31, 2025, respectively, because the nature of those adjustments is the same or similar to adjustments that I will have already discussed in the context of PECO Exhibit MJT-1. However, I will specifically address any additional adjustments or other differences among those exhibits.

8. Q. Please provide an overview of your accounting exhibits.

A. Exhibit MJT-1, which presents PECO's revenue requirement for the FPFTY ending December 31, 2027, is comprised of five sections, as follows:

Section I consists of a summary schedule setting forth PECO's claimed measures of value (i.e., rate base) and the derivation of the Company's requested rate increase.

Section II contains basic accounting data, primarily extracted from the Company's financial records, including a FPFTY-end balance sheet; statements of net operating income and FPFTY revenues; a schedule of expense items by primary account; and a calculation of PECO's tax expenses. Also included are schedules developing PECO's embedded costs of debt and equity, its FPFTY capital structure, and the Company's overall claimed rate of return.

Section III provides a detailed development of the major components of the Company's rate base claim. This section includes summaries of the original cost and accumulated depreciation at FPFTY-end of the various categories of utility plant, including allocated common plant, and calculations of PECO's working capital, materials and supplies, accumulated deferred income taxes ("ADIT"), regulatory liability for excess ADIT, and customer deposits and advances.

Section IV contains detailed adjustments required to place FPFTY revenues and expenses on a ratemaking basis. These adjustments are summarized on Schedules D-3 to D-17, and, together with certain tax adjustments, are carried forward to Schedule D-1 to derive PECO's pro forma operating income at present and proposed rates.

Section V briefly describes the FTY and HTY data.

Exhibits MJT-2 and MJT-3 are essentially identical in format. Adjustments were made to budgeted data, where necessary, to ensure that the Company's claimed revenue, expenses, and taxes are representative of the levels that the Company expects to experience on a normalized, ongoing basis, and in accordance with the Commission's established ratemaking precedent.

Because PECO is basing its requested rate increase on FPFTY data, Exhibit MJT-1 is key to understanding and evaluating the derivation of the Company's claimed revenue requirement. Exhibit MJT-2 follows the same format as Exhibit MJT-1, but presents information for the FTY ending on December 31, 2026. Exhibit MJT-3 follows the same format as Exhibits MJT-1 and MJT-2, but presents information for the HTY, which ended on December 31, 2025. This information is being furnished in accordance with the Commission's filing requirements and provides a basis for comparing PECO's FPFTY claims to the actual results of historic operations, adjusted for ratemaking purposes, for the HTY.

9. Q. How is the balance of your testimony structured?

A. In Section II of my testimony, I present an overview of PECO's FPFTY revenue requirement and explain, in summary fashion, how the claimed measures of value, pro forma present rate revenues, operating expenses, depreciation and taxes were determined. Section III of my testimony provides a more detailed description of the individual components comprising PECO's requested measures of value for the FPFTY, while Section IV of my testimony discusses the derivation, including appropriate ratemaking adjustments, of PECO's revenue and expense claims for the FPFTY. Section V of my testimony briefly describes the FTY and the HTY data.

II. OVERVIEW OF PECO'S FULLY PROJECTED FUTURE TEST YEAR REVENUE REQUIREMENT

10. Q. Please provide an overview of how the Company's FPFTY measures of value were determined.

A. PECO's measures of value, as presented in PECO Exhibit MJT-1, consist of nine principal components: (1) the depreciated original cost of utility plant-in-service (original cost less accumulated depreciation); (2) cash working capital; (3) ADIT; (4) a pension asset; (5) customer deposits; (6) customer advances for construction; (7) materials and supplies; (8) the regulatory liability for excess ADIT; and (9) gas storage inventory. Each is described briefly below.

Depreciated Original Cost of Utility Plant-in-Service. To determine utility plant-in-service at the end of the FTY, I began with the closing plant balances actually recorded on the Company's books of account on December 31, 2025, including allocated common plant. To those balances, I added the budgeted capital expenditures for PECO projects that are scheduled to close to plant-in-service (i.e., be placed into service) during the FTY and subtracted the anticipated plant retirements. The same process was used to develop utility plant-in-service balances as of the end of the FPFTY, beginning with the projected balance of plant-in-service on December 31, 2026, adding capital expenditures projected to be closed to plant-in-service by the end of the FPFTY, and subtracting anticipated retirements. The Company's claim for accumulated depreciation was determined in a similar fashion, starting with the accumulated depreciation on December 31, 2025 assigned to each plant account and bringing those data forward to reflect additional depreciation accruals, plant retirements, and cost of removal net of salvage for the period through December 31, 2026. Accumulated depreciation on December 31, 2027 was then deducted from the projected balance of utility plant as of that date to derive the Company's claimed FPFTY year-end net utility plant of $4.3 billion.

Cash Working Capital. Cash working capital was calculated using a lead-lag study and includes elements that are consistent with past practice and Commission precedent.

Pension Asset. PECO has included a pension asset in measures of value that consists of the portion of PECO's cash pension contributions that it will have neither recovered as an operating expense nor capitalized to utility plant because the capitalized amounts are based on costs determined pursuant to Financial Accounting Standards Codification Topic 715 ("ASC 715"), which was formerly Statement of Financial Accounting Standards 87 or "SFAS 87".

ADIT. The credit balance of ADIT includes the liability for deferred Federal income taxes, net of an offset (debit) for the ADIT assets related to Federal income tax paid by the Company in advance of recognizing the associated tax determinants for financial reporting purposes, which consist principally of contributions-in-aid-of-construction ("CIAC") recognized as income for income tax purposes.

Customer Deposits, Customer Advances for Construction, Gas Storage Inventory, and Material and Supplies. The claimed levels of customer deposits and customer advances for construction are deducted in determining the measures of value. The claimed levels of gas storage inventory and material and supplies are added in determining the measures of value. All the claimed levels are based on 13-month historic averages for the period ended December 31, 2025, consistent with Commission precedent.

Regulatory Liability for Excess ADIT. Due to the reduction in the Federal corporate tax rate that became effective on January 1, 2018 pursuant to the Tax

Cuts and Jobs Act ("TCJA"), there is "excess" ADIT. Excess ADIT represents taxes that were deferred prior to January 1, 2018 at the then-applicable 35% tax rate but will be paid to the Federal government, after January 1, 2018, at the current 21% tax rate. The excess ADIT is to be returned to customers over periods that correspond to the periods over which the ADIT would have been paid to the government if the Federal corporate tax rate had not been reduced. To reflect that obligation, the Company has transferred its excess ADIT from the Company's ADIT account to a new regulatory liability account. In addition, on July 8, 2022, Governor Tom Wolf signed Act 53 of 2022 into law. Act 53 incrementally changes the annual rate of Pennsylvania state tax on corporate net income ("CNI") from 9.99% to 4.99% over a period of nine years. Prior to Act 53 taking effect, the CNI tax rate was 9.99%. Act 53 initially lowered the CNI tax rate to 8.99% beginning on January 1, 2023. The CNI tax rate will be lowered each January 1 until the CNI tax rate reaches 4.99% by January 1, 2031. As a result, the Company made a reclassification of ADIT to excess ADIT at the end of 2022. It is important to note that this reclassification was based on the CNI tax rate of 4.99% in 2031. The impact of the CNI tax rate reduction in 2023 was addressed in the Company's 2022 base rate case proceeding at Docket No. R-2022-3031113, where a nine-year amortization for the associated excess ADIT was adopted as part of the approved settlement in that proceeding.[2] The additional impacts of CNI tax rate reductions beyond 2023 were passed to customers through the Company's State Tax Adjustment Clause. The sum of the Company's ADIT account and its regulatory

[2] *See Pa. P.U.C. v. PECO Energy Co. – Gas Div.*, Docket No. R-2022-3031113 (Order entered Oct. 27, 2022).

liability for excess ADIT on December 31, 2027 is deducted from the Company's measures of value.

The components of the measures of value described above are shown in PECO Exhibit MJT-1 on Schedule A-1 at lines 1 to 14 and are discussed in more detail in Section III of my testimony.

11. Q. How were the revenues at present rates derived?

A. Revenues at present rates were based on the budgeted revenues for PECO's gas operations for the FPFTY. Adjustments were made to: (1) annualize revenues related to changes in number of customers, including customers on PECO's Customer Assistance Plan ("CAP"), to reflect levels at the end of the FPFTY; (2) normalize revenues to reflect 365.25 days; and (3) normalize revenues using a 10-year historic average of weather data for purposes of determining projected sales and billing determinants in base rates as described by Company witness John Coursey in PECO Statement No. 5. These adjustments are summarized on Schedule D-5 of PECO Exhibit MJT-1 and are discussed in more detail later in my testimony.

12. Q. How were PECO's claimed operating expenses for the FPFTY determined?

A. The pro forma FPFTY expenses were determined using PECO's budget for the 12-month period ending December 31, 2027 as a starting point. Budgeted expenses, which were prepared based on business activities and related cost elements such as payroll, employee benefits, and outside contracting costs, were distributed to Federal Energy Regulatory Commission ("FERC") accounts based upon the actual distribution experienced by the Company during the calendar year ended December

31, 2025. The budget data were then annualized or normalized in accordance with established Commission ratemaking practices, and other appropriate adjustments were made, all of which are included in Schedule D of PECO Exhibit MJT-1. The necessary adjustments were made to the appropriate FERC accounts.

13. Q. Please describe how the taxes-other-than-income were determined for the FPFTY.

A. Those amounts were determined using budgeted amounts for the FPFTY, with pro forma adjustments to payroll taxes to reflect the impact of the FPFTY salaries and wages ("S&W") adjustments, as shown on Schedule D-16 of PECO Exhibit MJT-1.

14. Q. Please describe the calculation of depreciation expense for the FPFTY.

A. The development of annual depreciation for gas and common plant is set forth on Schedule D-17 of PECO Exhibit MJT-1. Each of pages 74 through 76 have columns numbered 1 through 5. Each of pages 77 through 79 have columns numbered 6 through 11. Each of pages 80 through 82 have columns numbered 12 through 17. Columns 1 through 5 show the annual depreciation for gas distribution and common plant. Column 6 shows the allocation factors used to allocate annual depreciation to the Gas Division. The allocation factor is 100% for gas distribution plant. For common plant, the allocation factor is 23.02%, which is the portion of common plant allocated to the Gas Division. Columns 7 through 11 show the annual depreciation allocated to the Gas Division. These figures are the same as those in columns 1 through 6 for gas distribution plant because it is allocated entirely to the Gas Division. The figures in columns 7 through 11 for common plant reflect the amounts in columns 1 through 6 multiplied by the allocation factor of 23.02%. Column 12 is designed to allocate utility costs between Commission jurisdictional service and non-Commission jurisdictional service. However, because PECO's Gas Division furnishes only Commission-jurisdictional service, the Functional Allocation Factor shown in column 12 is 100%. Accordingly, the amounts shown in columns 13 through 17 represent the amounts properly allocated in their entirety to Commission-jurisdictional service for the Gas Division. For all of the columns, the total for FERC Account 403 Depreciation Expense is shown on line 62 and the total for FERC Account 404 Amortization of Limited-Term Plant is shown on line 98.

The annual depreciation expense budgeted by the Company for gas distribution plant and total-Company common plant is $193.5 million, which is the sum of the amounts shown in column 1, lines 62 and 98. This amount is the annual depreciation developed by Company witness Mariana Hufford (PECO Statement No. 7) based on utility plant that will be in service on December 31, 2026 (as shown in Schedule D-17, column 3) and utility plant additions that will be in service on December 31, 2027 (as shown in Schedule D-17, column 2). As Ms. Hufford explains, the budgeted annual depreciation amounts for both plant-in-service on December 31, 2026 and for additions during the 12 months ending December 31, 2027 were calculated using depreciation rates that reflect the service life parameters developed in the Company's 2023 service life study filed in Docket No. M-2025-3054816. The annual depreciation for plant additions made during the 12-month period ending December 31, 2027 is based on their expected actual in-service dates and, therefore, reflects less than 12 months of depreciation for that plant. Accordingly, Schedule D-17, column 4, adjusts the amounts in column 1 to annualize the annual depreciation on plant additions made during the 12-month period ending December 31, 2027. Depreciation expense does not include Asset Retirement Obligations.

The resulting pro forma FPFTY depreciation expense of $211.1 million related to gas distribution plant and common plant is shown in column 5, line 100. The resulting pro forma FPFTY depreciation expense for gas distribution and common plant allocable to the Gas Division's Commission-jurisdictional service is $131.7 million, as shown in column 17, line 100. That amount is the sum of $113.9 million shown on line 62 and $17.8 million shown on line 98.

15. Q. How were income taxes calculated?

A. Income taxes were calculated using procedures consistent with Commission practice. Federal income tax expense was calculated at the 21% Federal corporate tax rate. The interest expense deduction was synchronized with the Company's measures of value and claimed weighted average cost of long-term debt. The normalization method was used to reflect the tax-book timing differences associated with the use of accelerated methods of tax depreciation to the extent permitted by the Commission and legal precedent. Tax expense was reduced to reflect the amortization of the unamortized investment tax credits ("ITCs"). Tax expense was also reduced to reflect the flow-back of excess ADIT that results from the TCJA's reduction of the Federal corporate tax rate and Pennsylvania CNI tax rate reductions. The income tax claimed for the FPFTY at present rate and proposed rate revenue levels is shown on PECO Exhibit MJT-1, Schedule D-18.

16. Q. Please describe how the pro forma revenue increase and revenues at proposed rates were established.

A. Schedule A-1 of PECO Exhibit MJT-1 shows the calculation of PECO's claimed revenue requirement and its requested revenue increase. Column 2, lines 1 to 16, summarize the pro forma measures of value.

Column 2, line 19, shows the Company's gas distribution base rate revenue at present rates. Column 3, line 19, shows the increase over revenues at present rates needed to recover the Company's FPFTY revenue requirement, which is $81.3 million.

Lines 18 to 46 of column 2 set forth the calculation of the increase above present rate revenue required to provide the Company with the opportunity to earn the overall rate of return of 8.08% calculated on Schedule B-7 and supported by Company witness Ann E. Bulkley (PECO Statement No. 8). The resulting required increase in net operating income on line 42 was increased by the Gross Revenue Conversion Factor ("GRCF"), shown on line 44, to provide for revenue from forfeited discounts, uncollectible accounts expenses, regulatory fees and income taxes on the increased revenues requested. The revenue increase shown on line 46 of column 2 is the difference between present rate revenue and revenues at proposed rates. The increase in unadjusted present rate revenue of $81.3 million is shown on line 46 of column 2 and line 19 of column 3. Column 3, lines 19 through 31, also contain the calculation of the revenue and expenses related to the proposed revenue increase.

Measures of value, revenues and expenses at proposed rates are shown in column 4, with the resulting overall rate of return of 8.08% shown on line 33 of column 4.

17. Q. What is the overall required increase in annual revenues for the Company's gas distribution operations for the FPFTY?

A. As shown on line 46 of PECO Exhibit MJT-1, Schedule A-1, the proposed increase in annual operating revenues is approximately $81.3 million.

18. Q. What is contained in Schedule B?

A. Schedule B consists of a balance sheet for the total Company on December 31, 2027 reflecting the Company's budget for the 12 months ending December 31, 2027 (Schedule B-1); a statement of Pennsylvania jurisdictional net operating income for the 12 months ending December 31, 2027 (Schedule B-2); a statement of Pennsylvania jurisdictional operating revenue for the 12 months ending December 31, 2027 (Schedule B-3); a statement of Pennsylvania jurisdictional operating and maintenance expense for the 12 months ending December 31, 2027 (Schedule B-4); a detailed breakdown of Pennsylvania jurisdictional taxes other than income for the 12 months ending December 31, 2027 (Schedule B-5); PECO's projected composite cost of long-term debt on December 31, 2027 (Schedule B-6); and the calculation of PECO's claimed overall rate of return for the FPFTY (Schedule B-7).

III. MEASURES OF VALUE

A. Summary of Measures of Value

19. Q. Please describe Schedule C-1 of PECO Exhibit MJT-1.

A. Schedule C-1 summarizes the measures of value for the FPFTY for the Company's total Gas Division. Column 1 identifies the schedule where each of the measures of value elements is derived, and columns 2 to 4 show the Company's total Gas Division amounts. The Company's claimed measures of value for the FPFTY, as shown in column 4, on line 14, is approximately $4.0 billion.

B. Plant-In-Service

20. Q. Please describe Schedule C-2 of PECO Exhibit MJT-1.

A. Schedule C-2 contains five pages and presents the Company's claimed FPFTY utility plant-in-service.

21. Q. What is shown on Schedule C-2, page 15?

A. Schedule C-2, page 15, is a summary of estimated year-end plant-in-service balances for the FPFTY by functional plant category. Column 4 reflects the Company's estimated gas distribution plant-in-service at the end of the FPFTY of $5.3 billion (line 36), which is shown on PECO Exhibit MJT-1, Schedule A-1, at column 2, line 2.

22. Q. How was total utility plant-in-service for the Gas Division of $5.3 billion, shown on Schedule C-2, page 15, column 4, line 36, determined?

A. The amount of $5.3 billion represents the estimated plant-in-service balance on December 31, 2027 for the Gas Division, exclusive of allocated common plant, and is based on utility plant-in-service on December 31, 2025, plus budgeted capital expenditures estimated to be closed to plant-in-service in the FTY and FPFTY, less the estimated retirements in the FTY and FPFTY.

23. Q. What is shown on Schedule C-2, page 16?

A. Page 16 sets forth the Company's estimated additions to be closed to plant-in-service during the FPFTY. These data were developed based on the FPFTY capital budget. The total-Company additions of $318.5 million are shown on line 33, column 1.

24. Q. What is shown on Schedule C-2, page 17?

A. Page 17 of Schedule C-2 presents the estimated plant retirements for the FPFTY, based on the average of actual retirements for the period of January 1, 2023 through December 31, 2025.

C. Accumulated Depreciation

25. Q. What is the purpose of Schedule C-3 of PECO Exhibit MJT-1?

A. This schedule, consisting of three pages, presents the provision for accumulated depreciation on December 31, 2027 by FERC account, as developed by Company witness Hufford, and cost of removal net of salvage, as explained more fully below. PECO's accumulated depreciation of approximately $1.2 billion is summarized on Schedule C-3, page 20, and carried forward to Schedule A-1, line 3.

26. Q. Please describe Schedule C-3, page 20.

A. This page shows the accumulated depreciation balance for the FPFTY by account category.

27. Q. What is shown on Schedule C-3, page 21?

A. Page 21 shows the accumulated depreciation balance by FERC account at the end of the FPFTY. To determine the accumulated depreciation balance at the end of FPFTY, the Company started with the accumulated depreciation balance on December 31, 2025 and added depreciation expense, less retirements and cost of removal net of salvage, for the FTY and FPFTY. Schedule C-3 page 22 shows the cost of removal net of salvage included in the FPFTY accumulated depreciation calculations, based on the average of actual cost of removal net of salvage for the period of January 1, 2023 through December 31, 2025.

D. Cash Working Capital

28. Q. What is set forth on Schedule C-4, page 23 of PECO Exhibit MJT-1?

A. This is a summary of the Cash Working Capital ("CWC") calculations, which are detailed on pages 24 to 31. The total of $21.7 million shown on line 27 is included in PECO's claimed measures of value, as shown on PECO Exhibit MJT-1, Schedule A-1, columns 2 and 4, line 7. Page 23 summarizes the derivation of PECO's revenue collection lag and overall operating expense payment lag. The revenue lag of 53.53 days is shown on line 3. The expense lag days for each of the components of operating and maintenance expenses appear on lines 6 to 10. Line 9 shows the lag associated with the purchase of accounts receivable from natural gas suppliers ("NGS") pursuant to PECO's Commission-approved purchase of receivables ("POR") program. The composite operating and maintenance expense and POR payment lag of 35.62 days is shown on line 13. The net lag of 17.91 days (53.53 – 35.62) shown on line 15 is multiplied by the average daily operating expense balance on line 19 to arrive at the base CWC amount of $27.0 million for operating expenses shown on line 21. The average daily operating expense balance of $1.5 million on line 19 was determined by dividing the total pro forma annual operating expenses, excluding uncollectible accounts expense, of $549.5 million on line 11, column 2, by the number of days in a year, 365. The other components of CWC are shown on lines 23 to 25 and will be described in connection with my discussion of related supporting schedules.

29. Q. Please describe the revenue lag calculation shown on Schedule C-4, page 24.

A. The total revenue lag days shown on line 29 of 53.53 days consist of three parts. First, the total of the month-end accounts receivable balances for the 13 months ended December 31, 2025 (shown in column 2 on line 17) was divided by 13 to calculate an average accounts receivable factor. Annual revenue billed during the 12 months ended December 31, 2025 was then divided by the average accounts receivable balance to calculate an accounts receivable turnover rate of 9.78 (column 4, line 21). A turnover rate of 9.78 is equivalent to 37.32 revenue lag days (365 days divided by 9.78 accounts receivable turnover rate), as shown in column 5 on line 21. This is referred to as the collection lag or the payment portion of the revenue lag. The payment portion of the revenue lag is added to (1) the one-day lag between the meter reading date and the day that bills are recorded as revenue and accounts receivable by the Company and (2) the 15.21-day period from the mid-point of the service period until the meter reading date, to calculate the total revenue lag of 53.53 days, as shown on line 29.

30. Q. **How was the mid-point of the service period calculated?**

A. The mid-point of the service period is equal to the days in an average month (365 days divided by 12, or 30.42 days) divided by two, or 15.21 days.

31. Q. **Please describe Schedule C-4, page 25.**

A. Schedule C-4, page 25, shows the calculation of the expense lags used in the CWC calculation. Lines 1 to 5 reflect the payroll expense lag. The payroll amounts for the FPFTY are developed on Schedule D-6. The lag periods for the payment of union and non-union payroll are combined because all employees are paid on the same schedule. The lag days reflect PECO's 2026 payment cycles, the last full year for which the payment cycles are known. Lines 7 to 15 show the lag in the payment of pension costs during the FPFTY. The lag period is calculated using a mid-point of July 1 and the payment dates shown in column 2. This results in an average payment lead of 167 days, which was applied to the pro forma pension expense derived from Schedule D-9, line 13 and shown on Schedule C-4, page 23, line 7.

32. Q. **How did you develop the lag days associated with the purchased gas costs shown on line 8 of Schedule C-4, page 23?**

A. The lag in payment of purchased gas costs is based on an analysis of gas payments during the HTY. The total dollar amount of payments during that period was $285.8 million and the average payment lag equaled 30.55 days. The latter figure was calculated using the mid-point of the service period for each of the payments and the payment date for each, averaged for the entire year's worth of data.

33. Q. How was the expense lag of 56.21 days for POR payments determined?

A. PECO pays NGSs 40 days after bill-ready data are provided by the NGSs to the Company for both residential and commercial and industrial accounts. The weighted average payment lag for all accounts is 40 days, as shown on page 31, line 3. The NGSs provide bill-ready data (page 31, line 5) to PECO one day after the meter reading date, and there is an average of 15.21 days from the mid-point of a service period to the meter reading date (page 31, line 6). The total payment lag, therefore, is 56.21 days (page 31, line 7).

34. Q. Please describe how you determined the payment lag associated with other operating and maintenance expenses.

A. The average payment lag for all remaining expenses, as set forth on lines 19 to 24 of Schedule C-4, page 25, was derived from data for the four months shown in detail on Schedule C-4, page 26. More specifically, the Company obtained a listing of all cash disbursements during each of the four months displayed in a format that shows the payee, the date of service or the invoice receipt date, the amount of the disbursement, the date the payment cleared the bank, the account to which the disbursement was charged and certain other data. Each month contains thousands of cash disbursements.

35. Q. How did you utilize the data?

A. I used the data in the column showing the number of days it took each disbursement to clear the bank from the invoice receipt date or service date to calculate the dollar days (the amount of the disbursement times the number of days the payment took to clear the bank) and sorted the disbursements by amount. I then eliminated disbursements that should not be included in a CWC calculation or that are included elsewhere in the CWC calculation.

36. Q. What disbursements did you eliminate from the balances used on Schedule C-4, page 26?

A. First, I eliminated all disbursements related to capital charges because they are not part of the Company's claimed operating expenses. Second, I eliminated all disbursements under $1,000 since those amounts, while significant in number, would not have a meaningful impact on the overall lag-day calculation. Third, I removed all commodity purchases since those are reflected in separate CWC calculations, as I previously described, and are recovered through a separate surcharge. Fourth, I removed all amounts charged to non-expense accounts and any charitable contributions. This process was completed for each of the four months shown on page 26, lines 1 to 11. The total cash disbursements for all four months of $106.4 million, as shown in column 2, on line 14, of page 26 of Schedule C-4, and the related dollar-days of $4.6 billion, shown in column 3, were used to calculate the payment lag for general expenses of 43.21 days shown in column 4. The 43.21 lag days for Other Disbursements were then brought forward to page 23 of Schedule C-4, line 10.

37. Q. Describe what is shown on Schedule C-4, page 27.

A. This page shows the calculation of the net payment lag days for the tax expense components of PECO's CWC allowance. The first two columns, which are not numbered, identify the type of tax and show the applicable payment schedule for each tax. The payment dates are shown in column 1. The payment lead or (lag) from the mid-point of the year is shown in column 3. The pro forma amount of the payment for each tax is shown in column 4. For example, the pro forma Federal income tax amount, based on the Company's proposed revenue level, is $1.5 million, as shown in column 4, lines 1 through 4. The required amounts are shown by payment date for each tax in column 6. The weighted lead (lag) amount for each payment for each tax is calculated in column 7. The weighted lead (lag) days are netted against the revenue lag days shown on page 28, column 4. The net payment lag shown on page 28, column 5, is used to calculate the average daily amount for working capital shown on page 28, column 7. The net total of the amounts in column 7 are shown on Schedule C-4, page 23, column 2, line 24.

38. Q. Please describe the calculation of the interest expense lag shown on page 29 and included on Schedule C-4, page 23.

A. This calculation measures the lag associated with the semi-annual payment of interest on outstanding debt. The pro forma interest expense is the amount resulting from the synchronized interest calculation using the pro forma measures of value and the weighted cost of debt included in PECO's requested rate of return. The daily interest expense amount, calculated on line 6, is multiplied by the net payment lag of 37.72 days for a reduction to the working capital allowance of $9.2 million, as shown on page 29 at line 10 and on page 23 at line 25.

39. Q. Please explain how the average prepayments of $2.6 million shown on Schedule C-4, page 30, line 25, were determined.

A. That amount is calculated on Schedule C-4, page 30, and represents the 13-month average of actual amounts at the end of each month from December 2024 to

December 2025. The Company reviewed its prepaid accounts and selected only those prepaid expenses that were related, in whole or in part, to its gas delivery operations. The resulting prepaid accounts are shown in columns 2 to 16 of page 30. Where the account related to both gas and electric operations, the total and average were distributed using an appropriate allocation factor that eliminates non-gas related expenses, as shown on line 17 in columns 10 to 16. The 13-month average for prepaid expenses for the gas distribution operations is $2.6 million as shown on line 25 of Schedule C-4, page 30 and on Schedule C-4, page 23, line 23.

40. Q. What is the total amount of CWC included in the claimed measures of value?

A. That amount is the $21.7 million shown on Schedule C-4, page 23, line 27 and on Schedule A-1, page 1, line 7.

E. Pension Asset

41. Q. Please describe Schedule C-5.

A. Schedule C-5 shows the calculation of the pension asset of $33.9 million (column 2, line 8) that the Company has included in measures of value. The pension asset represents the portion of the Company's net aggregate total of pension costs to be incurred at the end of the FPFTY, calculated in the manner required for ratemaking purposes, that was not, and will not be, recovered in operating expenses and was also not, and will not be, capitalized to its plant accounts. This asset represents the difference between the manner in which pension expense is calculated for ratemaking purposes and the manner in which pension costs are determined for purposes of calculating the labor loading rate used to capitalize a portion of pension costs under applicable Generally Accepted Accounting Principles ("GAAP").

Specifically, for ratemaking purposes, consistent with Commission policy and practice, PECO has historically claimed for recovery its cash contributions to its pension fund, while GAAP requires pension costs to be determined on the basis of different rules, which are set forth in ASC 715. PECO must capitalize and include in its plant accounts an amount that is based on pension costs calculated on the basis of ASC 715. This means that the amounts that are assumed for ratemaking to be included in PECO's plant accounts (based on the application of a capitalization rate to the cash pension contribution) necessarily differ from the amounts that are actually capitalized by PECO by applying, as it must, GAAP rules.

Using the FPFTY ending December 31, 2027, as an example, as shown on Schedule D-9, PECO's total pension cash contribution will be $7.5 million, of which 18.56% is attributable to natural gas distribution operations. PECO's capitalization rate is 42.01%. Therefore, $0.6 million ($7.5 million x 18.56% x 42.01 %) was assumed to be capitalized and included in applicable plant accounts. However, in the FPFTY, as in each prior 12-month period, the amount PECO included in applicable plant accounts for capitalized pension costs was calculated on the basis of ASC 715, as GAAP and applicable financial reporting mandates require. For the FPFTY ending December 31, 2027, the amount of pension cost actually capitalized would be $1.7 million. As a consequence, there was a gap of ($0.9) million of pension costs. As shown on Schedule C-5, the pension asset balance at the end of the FPFTY will be $33.9 million for natural gas distribution operations.

42. Q. Why should the pension asset be included in PECO's rate base?

A. The pension asset reflects the difference between: (1) the amount of pension cost the Commission assumes was included in PECO's plant accounts; and (2) the amount of pension costs actually included in PECO's plant accounts. That difference is $33.9 million. The pension asset, therefore, consists of $33.9 million of PECO-supplied capital that was actually contributed to PECO's pension fund and assumed for ratemaking purposes to be included in PECO's plant accounts, but was not recorded in PECO's plant accounts because GAAP rules will not allow it. PECO has included the pension asset in rate base in this case because, unless it is given rate base recognition, PECO will never recover the carrying costs it incurs on those PECO-supplied funds.

In addition, PECO's pension expense is reduced by the returns associated with the externally funded pension asset. Returns earned on pension assets within the pension fund remain within the fund, reduce pension contributions and costs on a going-forward basis, and, in that way, benefit customers.

43. Q. PECO previously proposed a pension asset in its last fully litigated base rate case at Docket No. R-2020-3018929 (the "2020 Gas Rate Case"). What was the disposition of the Company's proposal at that time?

A. PECO's pension asset proposal was opposed by the Commission's Bureau of Investigation and Enforcement and the Office of Consumer Advocate. In the 2020 Gas Rate Case, the Commission recognized the conceptual basis for including a pension asset in rate base due to the difference between the amounts the Commission assumes will be capitalized for ratemaking purposes and the amounts that are actually capitalized under GAAP rules that public companies must follow.[3] Nonetheless, the Commission concluded that excluding the pension asset from rate base in that case was a "better practice" that strikes an "appropriate balance" of company and customer interests.[4]

44. Q. Does recognition of a pension asset as PECO proposes in this case reasonably balance the Company's and customer interests as envisioned by the Commission in the 2020 Gas Rate Case?

A. Yes. PECO's proposal to include a pension asset in rate base necessarily requires the recognition (as a deduction from rate base) of any similarly calculated pension liability that could arise in the future. Thus, PECO's approach affords both the Company and customers an accurate accounting for actual costs, including the time value of money, in a manner that is both certain and timely. In contrast, the Commission's ruling in the 2020 Gas Rate Case disregards the impact of the time-value of PECO-supplied funds and, as such, either PECO or its customers could be experiencing an unjustified penalty or windfall at any given point in time. In short, the exclusion of PECO's pension asset from rate base again in this case would perpetuate an imbalance of customer and company interests.

F. ADIT

45. Q. What is the purpose of Schedule C-6?

A. Schedule C-6 shows the December 31, 2027 balance of ADIT that is deducted in determining the measures of value. The ADIT shown on line 19 of $282.7 million

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3 *See Pa. P.U.C. v. PECO Energy Co. – Gas Div.*, Docket No. R-2020-3018929 (Opinion and Order entered June 22, 2021) (the "2020 Gas Rate Case Order"), p. 67.

4 *Id.* at 68.

reflects the Federal income tax that must be deferred in compliance with the normalization provisions pertaining to the use of accelerated tax depreciation for Federal income tax purposes on test year plant balances and other tax-book timing differences that have been normalized. The accelerated tax depreciation used in the determination of taxable income for Federal and state income tax expense calculations is reflected on Schedule D-18. As discussed in the direct testimony of Company witness Marissa Humphrey (PECO Statement No. 3), the ADIT includes the deferred tax asset associated with the new corporate alternative minimum tax ("CAMT") implemented by the IRS beginning in 2023.

46. Q. Have you made an adjustment for the Federal income tax on CIAC?

A. It was not necessary to make a separate adjustment for CIAC. CIAC is treated as a capital contribution for ratemaking purposes but is treated as taxable income for Federal income tax purposes. PECO pays the Federal income tax due on CIAC in the year the CIAC is received and included in taxable income. The associated tax payment is recorded as a debit to the ADIT account, which normally carries a credit balance. Consequently, the net effect of the calculation of ADIT properly reflects the tax-book timing difference related to taxes paid on CIAC.

47. Q. What is the amount of ADIT used in the measures of value?

A. The amount for gas distribution operations is $282.7 million, as shown on line 19 of Schedule C-6 and on line 9 of Schedule A-1, in columns 2 and 4.

G. Customer Deposits

48. Q. Please explain how you determined the amount of customer deposits on Schedule C-7 that was deducted from the claimed measures of value on Schedule A-1.

A. The customer deposits shown in column 4 (lines 1-13) reflect the month-end balances for the 13 months ended December 31, 2025. The Company maintains a joint customer deposit account because many of its customers use both its electric and natural gas services. Total Company customer deposits were allocated between electric and gas operations based on electric and gas customer class revenues. Schedule C-7 shows the customer deposits related solely to the Company's gas distribution operations.

49. Q. Where are these amounts of customer deposits and interest shown?

A. The total of customer deposits for all classes of gas distribution customers is a deduction to measures of value of $14.3 million, as shown on Schedule C-7, line 25 and on Schedule A-1, line 10, columns 2 and 4. The calculated interest expense related to these customer deposits of $684,000, as shown in Schedule D-12, is included in the Company's operating expenses, as shown on PECO Exhibit MJT-1, Schedule D-3, page 46, column 14, line 79.

H. Common Plant

50. Q. What is shown on Schedule C-8?

A. This schedule shows the common plant, net of accumulated depreciation, included in the measure of value on Schedule A-1.

I. Customer Advances for Construction

51. Q. What is contained on Schedule C-9?

A. This schedule shows the average monthly balance of customer advances for construction of $1.4 million on line 19, which is deducted in calculating the measures of value on Schedule A-1, line 11, columns 2 and 4.

52. Q. How were the monthly balances determined?

A. The Company was able to identify the specific amounts attributable to its gas distribution operations based on a review of its accounting records.

J. Materials and Supplies

53. Q. Please describe Schedule C-11.

A. Schedule C-11 shows the derivation of PECO's claim for materials and supplies and undistributed stores expense. The materials and supplies balances in column 2 were specifically identified as gas distribution-related amounts and, therefore, 100% of those amounts is shown on line 20 in column 2. The undistributed stores expense shown in column 3 reflects amounts attributable to PECO's total utility operations and, therefore, the gas distribution allocation factor of 23.02% was applied to determine the 13-month average of monthly balances, as shown on line 22, in column 3. The claimed amount of $0.6 million reflected in column 4 is based on the 13-month average for the period ended December 31, 2025 and is shown on line 12, columns 2 and 4, of the measures of value on Schedule A-1.

K. ADIT – Regulatory Liability

54. Q. What is shown in Schedule C-12?

A. Schedule C-12 shows the calculation of excess ADIT that has been removed from the ADIT account and recorded as a regulatory liability.

L. Gas Storage Inventory

55. Q. What is shown on Schedule C-13?

A. This schedule shows the calculation of the gas storage inventory included in the measures of value on Schedule A-1. The Company is using the 13-month average balance for the period ended December 31, 2025 for each of the stored underground, liquified natural gas and propane components.

56. Q. What is the Company's claimed measures of value in this proceeding?

A. PECO's claimed measures of value, or rate base, equals $4.0 billion, as shown on Schedule A-1, line 16.

IV. REVENUES AND EXPENSES

57. Q. What is shown on Schedule D-1 of PECO Exhibit MJT-1?

A. Schedule D-1 is a summary income statement that depicts PECO's claimed gas revenues, expenses and taxes at present and proposed rate levels. The derivation of most of the individual line items will be discussed in connection with the remaining schedules in Section D. Schedule D-1 also shows the proposed revenue increase of $81.3 million in column 3, line 10.

58. Q. What is the indicated net operating income before interest and income taxes at proposed rates?

A. As shown on Schedule D-1, column 4, line 30 and also on Schedule A-1, column 4, line 26, that amount is $334.7 million.

59. Q. Please describe Schedule D-2.

A. Schedule D-2 shows the derivation of the various line items on Schedule D-1, column 2. Schedule D-2 begins with the Company's budgeted revenues and expenses for the FPFTY, in column 1, and then annualizes and/or normalizes those figures through adjustments summarized in column 2. The pro forma data in column 3 are summarized and brought forward to Schedule D-1 and used in the determination of the required revenue increase. The various revenue adjustments in column 2 are summarized on Schedule D-3 and listed by adjustment on Schedule D-5, and the expense adjustments are summarized on Schedule D-3 and described in more detail on the separate adjustment schedules beginning with Schedule D-6 and continuing through Schedule D-17.

60. Q. Please describe Schedule D-3.

A. Schedule D-3 summarizes the various adjustments that were made to the budgeted revenue and expense data to derive the pro forma amounts at present rates that appear in column 3 of Schedule D-2 and are included in the adjusted amounts that are carried forward to column 2 of Schedule D-1. The FPFTY budgeted amounts are shown in column 1 and the revenue adjustment totals are shown in columns 2 to 7. The various expense adjustments are reflected in columns 8 to 19. Each of the pro forma adjustments will be described in connection with the specific schedule supporting the adjustment. The pro forma adjusted amounts for the FPFTY are shown in column 21.

61. Q. Please describe Schedule D-4.

A. Schedule D-4 contains four pages and presents a summary of the pro forma operating expenses shown on Schedule D-3 by FERC account.

A. Revenue Adjustments

62. Q. Please describe Schedule D-5.

A. Schedule D-5 presents a summary of the separate pro forma adjustments to revenue for the FPFTY. Each of these adjustments will be described in detail in connection with the separate calculation of the adjustment shown on Schedules D-5A to D-5F.

63. Q. How did you calculate the revenue adjustment shown on Schedule D-5A?

A. This adjustment annualizes distribution revenues for the projected number of customers at the end of the FPFTY. As shown on lines 1 to 5, for all retail customer classifications this calculation determines the test-year net distribution revenues at present rates for the FPFTY. The net distribution revenues on line 5 were divided by the average number of customers for the budget for the 12 months ending December 31, 2027 on line 7 to determine the average distribution revenue per customer on line 9. The average distribution revenue, or margin, per customer for the FPFTY on line 9 was then multiplied by the difference between: (1) the average number of customers (line 7); and (2) the number of customers at the end of the FPFTY (line 11). The products of those calculations yield additional revenue of approximately $1.1 million for the residential and commercial and industrial customer classes. This pro forma adjustment is then reflected on Schedule D-5, column 2, by customer classification.

64. Q. Please describe the adjustment calculated on Schedule D-5B.

A. This adjustment annualizes the cost of the discounts provided to customers enrolled in PECO's CAP in the form of a bill credit, reflecting the number of CAP customers at the end of the FPFTY. As shown in line 8, the average CAP discount per CAP customer is determined by dividing the total budgeted CAP discount on line 1 by the average number of CAP customers shown on line 7. The average CAP discount per CAP customer is then multiplied by the difference between the FPFTY year-end CAP customers on line 10 and the average number of CAP customers shown on line 7. This yields an increase in the CAP discount of $227,000, which is offset by adjustments for uncollectible accounts factor of 8.2% and CWC factor of 3.7% as shown on line 15. These offset factors are discussed in more detail by Company witness Joseph A. Bisti (PECO Statement No. 10). The net change of $200,000 is shown on line 17, which is brought forward to column 3 in Schedule D-5.

65. Q. Please describe the adjustment shown on Schedule D-5C.

A. This adjustment normalizes revenue the Company budgeted for the FPFTY by increasing variable distribution service charge revenue to reflect an additional 0.25 days. The Company's budgeted revenue for the FPFTY is based on 365 days, reflecting the 28 calendar days in February 2027. This adjustment normalizes revenue to reflect the average number of days in the month of February over a four-year cycle that includes one leap year. The customer charge revenue does not change irrespective of the number of days in a year and, therefore, is not adjusted in this schedule. Additionally, the classes have variable distribution service charges that apply to each thousand cubic feet ("Mcf") of usage and, therefore, are sensitive to the number of days of usage in the test year. Line 1 of Schedule D-5C shows the non-customer and non-reconcilable surcharge distribution revenue by customer class for February 2025. Lines 2 and 4 show the number of days in February 2025 and the normalized number of days in that month over a four-year cycle. The difference is shown in line 5. The adjustment necessary to normalize revenues for 0.25 days is shown, by class, on line 7.

66. Q. Please describe the adjustment calculated on Schedule D-5E.

A. This schedule reflects the elimination of asset optimization revenues representing the Company's net margin from off-system sales and capacity release credits. Customers receive their share of the net proceeds from these sales and capacity releases through the Purchased Gas Cost rate, and the Company retains its appropriate share of the margin, which is recorded below the line for ratemaking purposes.

67. Q. Please describe the adjustment calculated on Schedule D-5F.

A. PECO's gas forecasts have historically utilized "weather normal" assumptions based on weather averages from the prior 30 years, and are recalculated annually using the latest 30-year period. In this case, the Company is proposing to use a 10-year period for defining normal weather for base-rate sales and billing determinants and the calculation of the Weather Normalization Adjustment. These proposals are discussed in more detail in the direct testimony of Mr. Coursey (PECO Statement No. 5) and John D. Taylor (PECO Statement No. 6). The adjustment on Schedule

D-5F normalizes the revenue the Company budgeted for the FPFTY to reflect normal weather on a 10-year instead of 30-year basis, which as shown on line 7, results in a $19.4 million reduction to revenues.

B. Operating Expense Adjustments

68. Q. Does the Company budget its operating expenses by FERC account?

A. No. As I mentioned previously, it does not. Rather, the Company budgets its operating expenses by cost element or business activity, such as payroll, employee benefits, and rent.

69. Q. How were the FPFTY data restated by FERC account for purposes of preparing the Company's supporting data in this case?

A. The amounts recorded in FERC accounts as of the end of the HTY were analyzed to develop a chart showing charges for each cost element within each FERC account. After this process was completed, I then distributed the forecasted FPFTY charges by cost elements in those cost categories to the corresponding FERC accounts based upon the ratios experienced in the HTY. For example, I determined how much of the S&W expensed in the HTY was charged to each FERC account and then distributed the FPFTY forecasted S&W to each FERC account based on those ratios. This process was used for each cost category to transform the FPFTY expense forecast by cost element to a FERC-based forecast. This FERC-based forecast is brought forward to Schedule B-4.

70. Q. Why was it necessary to transform the FPFTY cost-category forecast to a FERC-account based forecast?

A. It was done for two reasons. First, the Company's annual reports to the Commission are presented on a FERC-account basis and, therefore, having the FPFTY forecast presented in the same format facilitates a comparison of the FPFTY forecast data to prior years' experience. Second, it was necessary to have the FPFTY data available by FERC account for use by Company witness Jiang Ding (PECO Statement No. 9) in the cost-of-service study.

71. Q. In your opinion, does this process result in a fair presentation of the Company's FPFTY forecast expenses by FERC account?

A. Yes, it does.

72. Q. Were each of the pro forma adjustments reflected on Schedule D-4 also assigned to the appropriate FERC accounts?

A. Yes, they were.

73. Q. Are the various pro forma expense adjustments presented on Schedule D-4 shown by the type of expense and also by the FERC account distribution?

A. Yes, they are. The expense categories are identified in the headers of the columns on Schedule D-4, and each adjustment is described in connection with a separate schedule showing its derivation. These adjustments are shown by FERC expense category on Schedule D-4 and also on the Section D summary schedules.

74. Q. Please describe Schedule D-6.

A. Schedule D-6 consists of four pages and shows the calculation of the FPFTY annualization adjustments for S&W. Pages 59 and 60 show the calculation of the pro forma adjustments for overall S&W. Pages 61 and 62 contain the forecasted data for the FPFTY summarized by FERC account categories showing a total to be expensed of $50.0 million in column 1, line 73. Column 2 shows the annualization adjustment of $1.8 million distributed to the FERC expense categories, while column 3 provides the pro forma amounts for S&W expense, which totals $51.8 million, as shown on line 73. The adjustment of $1.8 million is reflected on Schedule D-4, column 3.

75. Q. How was the annualization adjustment derived?

A. The calculation is shown on Schedule D-6 pages 59 and 60. The adjustment annualizes budgeted S&W expense to reflect the number of employees at the end of the FPFTY and certain wage increases to become effective during the FPFTY or shortly after the FPFTY. More specifically, I have annualized: (1) the 3.0% wage increase for union employees forecasted to be effective on January 1, 2027 (lines 7 to 9 in column 2); (2) the 3.0% wage increase for non-union employees forecasted to be effective on March 1, 2027 (lines 7 to 9 in column 3); (3) the projected 3.0% wage increase for union employees to be effective on January 1, 2028 (lines 13 to 15 in column 2); and (4) the projected 3.0% wage increase for non-union employees to be effective on March 1, 2028 (lines 13 to 15 in column 3).

76. Q. Please explain the adjustment shown on Schedule D-6, page 60, lines 6 to 10.

A. This adjustment normalizes an estimated cash payment to be made to union employees in connection with the anticipated ratification of a new union contract later in 2026. The portion of the estimated payment that will be expensed ($1.303 million) was split between electric distribution, electric transmission and gas operations, and the amount allocated to gas distribution operations $242,000 was divided by six to reflect the estimated six-year term of the contract. The resulting amount of $40,000 shown in column 2, line 10, was added to the pro forma adjustment for S&W.

77. Q. Please explain the calculations shown on Schedule D-6, page 60, columns 1 and 2, lines 15-19.

A. These calculations annualize an increase in the number of employees during the FPFTY. As shown in column 2, line 15, the projected number of Company employees at the end of the FPFTY is 677. The average number of employees during the FPFTY is projected to be 676, which is the figure that the Company used to develop the S&W in its budget which is shown on line 1. The detailed calculation of the average number of employees included in the budgeted expense level is shown on Schedule D-8, page 64, in lines 2 to 15. The increase in employees shown in Schedule D-6, page 60, line 17, was multiplied by the average annual S&W per employee shown on line 18, to determine the total annualization adjustment to S&W of $119,000 due to the increase in number of employees, as shown on Schedule D-6, page 60, line 19. Because the average and year-end employee numbers reflect rounding to obtain the levels of full-time equivalent employees, the difference between those figures does not exactly match the figure on line 17.

78. Q. What is the total pro forma adjustment for S&W expense for the FPFTY?

A. The total amount is $1.786 million, which is an increase of 3.57% from the Company's S&W budget for the FPFTY, as shown on Schedule D-6, page 60, lines 23 and 25.

79. Q. Please describe Schedule D-7 of PECO Exhibit MJT-1.

A. Schedule D-7 shows the adjustment to normalize rate case expense. The Company expended approximately $78,000 on this filing during the 12 months ended December 31, 2025 (line 4) and has budgeted an additional $3.148 million (line 9) during the 12 months ending December 31, 2026. This total, $3.226 million (line 11), is normalized over a period of two years, as shown on line 13, column 2, which results in a total estimated normalized annual cost for this case of approximately $1.613 million, as shown on line 17, column 2.

80. Q. Please describe Schedule D-8 of PECO Exhibit MJT-1.

A. The bottom half of Schedule D-8 annualizes the non-pension employee benefits expense to reflect the full year's level of costs associated with the number of employees during the FPFTY. The annualization, reflecting an increase of $18,000 in non-pension benefit expense, was derived by using the increase in the number of employees on line 22 and the budgeted average non-pension benefit expense per employee of approximately $11,000 on line 21.

81. Please explain how you calculated the change in number of employees to a year-end level on Schedule D-8.

A. Line 15 shows the 12-month average of employees that is reflected in the Company's budget. I compared the 12-month average to the number of employees reflected in the budget to be employed on December 31, 2027. The difference is shown on line 16. Because the average and year-end employee numbers reflect rounding to obtain the levels of full-time equivalent employees, the difference between those figures does not exactly match the figure on line 16.

82. Q. What is contained in PECO Exhibit MJT-1 Schedule D-9?

A. Schedule D-9 shows the calculation of the Company's claim for pension expense, which is based on a five-year average of actual and projected contributions to its pension plan. The portion of the pension cost assigned to gas distribution operating expense in the FPFTY is $812,000, as shown on line 13, while PECO's FPFTY budgeted amount for pension expense is $1.7 million, as shown on line 14. Accordingly, an adjustment of ($878,000) has been made to the Company's FPFTY budget amount to reach the claimed amount of $812,000, as shown on line 15, and the adjustment amount was brought forward to Schedule D-3, column 11, line 95.

83. Q. What is presented on Schedule D-10 of PECO Exhibit MJT-1?

A. Schedule D-10 calculates an adjustment to the Company's budgeted uncollectible accounts expenses. Lines 1 to 4 calculate net uncollectible accounts charged off, excluding CAP Pre-Program Arrearage ("PPA") write-offs, as a percentage of total tariff revenue, based on an average of annual data for the period January 1, 2023 through December 31, 2025. That percentage was used to adjust the amount of uncollectible accounts expense in the budget to conform to the method historically used by the Commission for this expense. The resulting 0.5231% shown on line 4, column 4, of Schedule D-10 is applied to the pro forma revenues at present rates for the FPFTY to calculate the total pro forma amount for uncollectible accounts expenses at present rates of $4.95 million shown in column 5 on line 14. This reflects a net increase of $2.3 million, as shown on line 18 and brought forward to Schedule D-3 (column 12, line 80). In addition, the 0.5231% write-off rate is used in determining the level of uncollectible accounts expense at proposed rates, as shown in column 3 on line 19 of Schedule D-1.

84. **Q.** **Please describe the pro forma adjustment on Schedule D-11.**

A. Schedule D-11, page 67, column 2, line 3 reflects the incremental costs of $464,000 associated with PECO's proposed changes to its residential energy efficiency program as described by Company witness Clifton Krausz (PECO Statement No. 13). Schedule D-11 also includes an adjustment to reduce PECO's revenue requirement in this case by the amount of unspent funds collected in base rates for the Company's commercial energy efficiency programs during the period of January 1, 2024 through December 31, 2025. In total, these two adjustments increase PECO's revenue requirement by $438,000, as shown in column 2, line 7 and brought forward to Schedule D-3, column 13, line 111.

85. **Q.** **Please describe the pro forma adjustment on Schedule D-12.**

A. The adjustment shown on Schedule D-12 captures the interest expense that the Company must pay on customer deposits. Since the average balance of customer deposits is a reduction to measures of value, the interest expense is included as a pro forma expense for the FPFTY. The interest for residential customer deposits was calculated using an annual rate of interest of 7.0% and a monthly rate of 0.583%. An annual rate of 3.5% (a monthly rate of 0.292%) was used for commercial and industrial customers. The total pro forma expense of $684,000 is shown on Schedule D-12, line 33 and brought forward to Schedule D-3, column 14, line 79.

86. Q. Please explain what is shown on Schedule D-13.

A. Schedule D-13 shows the adjustment needed for PECO to recover costs to remediate former manufactured gas plant ("MGP") sites consistent with standards established by the Pennsylvania Department of Environmental Protection ("PADEP"). Each year, PECO reviews and updates the activities and costs associated with MGP remediation based on a report from its site consultants.

In the 2020 Gas Rate Case, the Commission directed the Company to recover the remaining remediation costs over a 14-year period.[5] The figure of $11.705 million on line 1 reflects the amount PECO will not have recovered for its MGP remediation liability in its current rates as of December 31, 2026. PECO is proposing to recover the regulatory asset for the remaining unrecovered MGP remediation liability over eight years, as shown on line 2 of Schedule D-13 and, therefore, has reflected an annual amortization amount of $1.463 million ($11.705 million/eight years) in its operating expense claim in this case, as shown on line 4 of that schedule. Accordingly, an adjustment of $32,000 has been made to the Company's FPFTY budget amount to reach the claimed amount of $1.463 million, as shown on line 8, and the adjustment amount was brought forward to Schedule D-3, column 15, line 111.

87. Q. How does PECO propose to recover any future changes in its estimated unrecovered MGP remediation costs?

A. Consistent with the framework approved by the Commission in prior rate cases, PECO previously established a regulatory asset to track and record any differences

[5] 2020 Gas Rate Case Order, pp. 122-123.

(positive or negative) between the annual amount of MGP remediation costs collected from customers through base rates and its updated MGP remediation liability from its site consultants, net of insurance recoveries, experienced during the applicable year. PECO proposes to reset its MGP remediation expense allowance in its next rate case based on a normalized annual level of the net balance of the regulatory asset. PECO believes this ratemaking treatment permits the Company to recover its costs in a reasonable manner while protecting customers and PECO from funding requirements if there is an over-or under-recovery during the MGP remediation process.

88. Q. Please describe the adjustments for miscellaneous items shown on Schedule D-14.

A. First, as noted by the Commission in the 2020 Gas Rate Case Order (pp. 122-23), PECO agreed to pay interest on the monthly balance of MGP funds that are not yet spent on remediation activities at the residential mortgage lending rate specified by the Secretary of the Pennsylvania Department of Banking and Securities after July 1, 2021. Line 1 reflects the total accrued interest of $1.316 million as of December 31, 2025 that has been applied to reduce PECO's revenue requirement in this case. As part of this proceeding, PECO proposes to collect interest on the monthly balance of MGP funds that are not yet collected from customers at the same interest rates the Company used to pay interest as described above. This adjustment reduces PECO's revenue requirement by $1.3 million, which is normalized over two years to arrive at the annual adjustment amount of ($658,000) shown in column 2, line 3. Accordingly, an adjustment of ($10,000) has been made to the Company's FPFTY budget amount to reach the claimed amount of ($658,000), as shown on line 5, and the adjustment amount was brought forward to Schedule D-3, column 16, line 79.

89. Q. Please describe the adjustments shown on Schedule D-15.

A. Schedule D-15, page 71, contains two adjustments to PECO's expenses related to its Gas Procurement Charge ("GPC") rate and Merchant Function Charge ("MFC") uncollectible write-off factors. First, PECO's expenses must be adjusted accordingly to reflect GPC-related reductions based on procurement-related costs. In 2013, PECO reached a settlement in Docket No. P-2012-2328614 to unbundle certain annual procurement costs from base rates and include those costs in its Price to Compare. In compliance with that settlement and the regulations set forth at 52 Pa. Code Sections 62.221-62.225, PECO unbundled certain procurement costs from its base rates for non-shopping participants in its Low Volume Transportation ("LVT") program, which consists primarily of residential and small business customers who are eligible for PECO's Supplier of Last Resort service. The GPC-related reduction is shown in column 2, line 7.

Schedule D-15 also includes an adjustment to PECO's distribution expenses related to its MFC charge. Consistent with the settlement of PECO's 2010 gas rate case, PECO was authorized in Docket No. P-2012-2328614 to implement an MFC to recover uncollectible accounts expenses related to gas supply.

PECO has applied the total cost reduction of $4.1 million to its total distribution expense for each impacted class, as shown in Schedule D-15, column 2.

C. Taxes – Other Than Income Taxes

90. Q. Please describe Schedule D-16 of PECO Exhibit MJT-1.

A. Schedule D-16 contains two pages. Page 72 is a summary showing the budgeted amounts for the FPFTY (column 1) for the Company's Gas Division, the total pro forma adjustments (column 2), and the pro forma expenses claimed in this case (column 3). The calculations of payroll-related changes are made on Schedule D-16, page 73. The increase in payroll taxes, shown on page 73, line 5, was calculated using the ratio of tax expense to payroll expense in the FPFTY forecast applied to the payroll tax expense for the FPFTY, which is an increase of $169,000. This amount is then reflected on page 72 in column 2, line 6.

D. Depreciation Expense

91. Q. What is shown on PECO Exhibit MJT-1, Schedule D-17, pages 74 to 82.

A. I described Schedule D-17 in detail earlier in my testimony. As I explained, Schedule D-17 shows the development of the Company's claims for annual depreciation for gas distribution and common plant. Schedule D-17 starts with the annual depreciation for gas distribution and common plant developed by Company witness Hufford and presented in PECO Exhibit MH-3. The adjustments set forth on Schedule D-17, in addition to allocating a portion of common plant to the Gas Division, annualize depreciation expense related FPFTY additions to reflect a full year's depreciation for that plant. PECO's total depreciation expense annualization adjustment for the Company's gas business is $7.1 million, which is the sum of the amounts shown on Schedule D-17, column 16, line 100.

E. Income Taxes

92. Q. Please describe the income tax calculation shown on PECO Exhibit MJT-1, Schedule D-18, pages 83 and 84.

A. This schedule calculates the pro forma income tax expense for the FPFTY at present and proposed rates, as set forth in columns 1 and 3, respectively. Line 1 shows the revenue at present rates, the revenue increase (with the related forfeited discounts increase), and revenue at proposed rates. Line 2 shows the total operating expenses at present rates, as well as changes related to the revenue increase and at the proposed rates from Schedule D-1. Line 3 shows the operating income before interest expense and income taxes. Synchronized interest expense is calculated on lines 5 to 7 using the total measures of value for the FPFTY on line 5 and the weighted cost of debt calculated on Schedule B-7 on line 6. The resulting interest expense on line 7 is used to reduce the taxable income to the amount shown on line 8.

In compliance with Commission practice, the difference between accelerated tax depreciation (line 10) and pro forma book depreciation (line 11) is used to adjust the state taxable income, as shown on line 8 to reflect the fact that the effects of accelerated depreciation are flowed through for state income tax purposes. In addition, there are adjustments to other tax-book differences and flow-through amounts, as shown on lines 13 to 18. These adjustments result in the net reduction of state taxable income from line 8 to line 20. The statutory state income tax rate of 6.99% was used to determine the pro forma current state income tax (expense)/credit shown on line 26. Federal income tax is calculated on lines 28 to

38 with a Federal corporate income tax rate of 21%. Line 43 shows the total current state and Federal income tax (expense)/credit before the amount for deferred income taxes is calculated. Lines 45 to 54 reflect the Federal and state deferred income taxes.

The total income tax (expense)/credit before other adjustments is shown on line 56 at present and proposed rates in columns 1 and 3, respectively, including the flow-back of excess ADIT resulting from the lower Federal corporate income tax rate under the TCJA and from the reduction of the Pennsylvania CNI tax rate, as discussed above. The other adjustments include the amortization of the ITC for gas distribution plant, including the portion of common plant allocated to gas distribution, as shown on line 59.

93. Q. Please explain the nature and calculation of the ITC amortization.

A. The ITC reflects tax credits used by the Company in years prior to 1987, the amortization of which will not have been completed by the end of the FPFTY. While the availability of the ITC ended in 1987, the credit has been amortized over the useful lives of the assets that generated it. The amortization for the FPFTY ending December 31, 2027 reduces income tax expense at both present and proposed rates, shown on Schedule D-18, page 84.

94. Q. Please explain the adjustment to flow-back excess ADIT.

A. As I previously explained, the TCJA reduced the Federal corporate income tax rate from 35% to 21%, effective January 1, 2018, and the Company's ADIT balances as of December 31, 2017 reflect taxes that were deferred at the higher corporate income tax rates in effect prior to January 1, 2018. PECO has recorded excess

ADIT in a regulatory liability account. For ADIT that relates to tax-book timing differences associated with utility plant subject to the normalization requirements of the Internal Revenue Code, PECO is required to flow back the difference between its ADIT balance and what its ADIT balance would have been if the deferrals had been made at the current 21% corporate tax rate (excess ADIT) over the remaining lives used in its books of account for the property that gave rise to the reserve for deferred taxes. The Company used the Average Rate Adjustment Method, as defined by applicable IRS regulations, for this purpose. Shorter flow-back periods are permissible for property that is not subject to normalization requirements. Schedule D-18, page 84, line 49, reflects the annual amount of the regulatory liability to be flowed back. As I explained earlier, for the excess ADIT resulting from changes to the Pennsylvania CNI tax rate, the Company made a reclassification of ADIT to excess ADIT at the end of 2022, based on the CNI tax rate of 4.99% in year 2031. The impact of the CNI reduction in 2023 was incorporated in the Company's 2022 base rate case proceeding under Docket No. R-2022-3031113 with a nine-year amortization for the associated excess ADIT. Schedule D-18, page 84, line 50 reflects the annual amount of the regulatory liability to be flowed back to customers over a period of nine years.

95. Q. What is PECO's total income tax expense claim in this proceeding?

A. As shown on Schedule D-18, page 84, line 61, column 1, pro forma income tax benefit at present rates equals $10.1 million. The increment for income tax expense associated with the proposed revenue increase is shown in column 2, in the amount of $21.4 million, and the total pro forma income tax credit at proposed rates of $11.3 million is shown in column 3.

96. Q. Please explain Schedule D-19.

A. This schedule shows the calculation of the GRCF used on Schedule A-1 to determine the revenues required to achieve the overall rate of return requested by PECO. The conversion factor captures the additional late payment revenue, uncollectible accounts expense, regulatory fees and Federal and state income taxes attributable to the additional revenues resulting from the proposed rate increase.

V. FUTURE TEST YEAR AND HISTORIC TEST YEAR

97. Q. Please describe the process used to prepare the pro forma FTY and HTY presentations in PECO Exhibit MJT-2 and PECO Exhibit MJT-3, respectively.

A. The basic process was the same as described in connection with PECO Exhibit MJT-1, except I used budgeted data for the FTY and actual recorded data for the HTY as the starting point for each exhibit. As with the FPFTY, I reviewed the budgeted data for the FTY and recorded data for the HTY and, where appropriate, made pro forma adjustments. In addition, I used data from PECO Exhibit MJT-1 as the basis for several of the pro forma amounts used in PECO Exhibits MJT-2 and MJT-3.

98. Q. What assumptions did you make to determine what pro forma adjustments would be necessary for the FTY and HTY?

A. I included pro forma adjustments that reflected the annualization and normalization of FTY and HTY elements and adjustments for future events that have impacted the FPFTY. For example, I have annualized S&W expense for increases and adjusted for the year-end number of employees, as I did in the FPFTY. The pro forma adjustments for the FTY and HTY are numbered consistently with the adjustments for the FPFTY. For example, the adjustment for S&W is on Schedule D-6 in all three test years to facilitate reference between the FPFTY, the FTY, and the HTY. Where there is no adjustment required for the FTY or the HTY, the correlation simply shows that further adjustment is not applicable.

99. Q. Referring now to PECO Exhibit MJT-2, for the FTY, what is contained on Schedule A-1?

A. Schedule A-1 shows a summary of the measures of value on lines 1 to 14, operating revenues and expenses and calculated rates of return at present and proposed rates on lines 18 to 33, and the revenue increase required on lines 35 to 46.

100. Q. What is contained on Schedules B-1 to B-5?

A. These schedules contain budgeted financial data for the FTY.

101. Q. Please describe Schedules B-6 and B-7.

A. These two schedules contain the FTY pro forma capital structure and rate of return developed by Ms. Bulkley. As shown on lines 1 to 3 of Schedule B-7, the Company is using its expected capital structure at the end of the FTY and cost rates as shown on Schedule B-7.

102. Q. Please describe Schedule C-1.

A. Schedule C-1 lists the measures of value components. The measures of value total for the FTY is $3.8 billion, as shown on column 4, line 14.

103. Q. What is contained in Schedule C-2?

A. Schedule C-2 consists of five pages and shows the utility plant-in-service balances on December 31, 2026 for the Company's gas operations, as well as the additions, retirements, and adjustments for the FTY. Pages 18 and 19 contain the summary of pro forma plant-in-service balances by plant grouping. Page 15 shows the plant-in-service by FERC account. Pages 16 and 17 show the additions to plant and retirements from plant during the FTY. Finally, adjustments to plant are reflected on pages 18 and 19. The total pro forma plant-in-service at the end of the FTY is $4.97 billion and is shown on Schedule C-2, page 15, column 4, line 36.

104. Q. Please describe Schedule C-3.

A. Schedule C-3 contains three pages and shows the accumulated depreciation on December 31, 2026. These pages show the pro forma balances by FERC account developed using the same procedures employed for the FPFTY. The accumulated depreciation at the end of the FTY is $1.09 billion, as shown on page 20, column 4, line 36.

105. Q. What is contained in Schedule C-4?

A. Schedule C-4 consists of nine pages that show the calculation of the CWC allowance for the FTY of $21.5 million on page 23, line 27. The information for average prepayments on line 23 is the same as utilized in PECO Exhibit MJT-1 because the FPFTY claim is based on the 13-month average for the period ended December 31, 2025. In addition to the prepayments, the methodology used to calculate the lag periods for revenue, payroll, pension expense, gas purchases and other disbursements utilized in PECO Exhibit MJT-1 were also used in the FTY calculation.

Page 23 provides a summary of the calculations for each of the elements of the CWC for the FTY. The expenses in column 2 and those included in the determination of the lead-lag amounts for taxes, interest, and preferred dividends are the pro forma amounts for the FTY, while the prepayment amount is the 13-month average of month-end balances through December 31, 2025. The resulting $21.5 million of CWC shown on line 27 is brought forward to Schedule A-1 in the calculation of the measures of value.

106. Q. Please describe Schedule C-4, pages 24 to 31.

A. These pages show the calculations of various leads and lags and working capital requirements for the FTY following the same procedures used for the FPFTY as described in connection with PECO Exhibit MJT-1, Schedule C-4. While the amounts for the FTY expenses vary from those in the FPFTY, the procedures followed to determine the lead/lag periods applied to those expense levels are the same as those described in connection with the corresponding PECO Exhibit MJT-1 schedules.

107. Q. What is contained on Schedule C-5?

A. Schedule C-5 shows the Company's claim for a pension asset to be included in the measures of value. The procedures to determine the asset are the same as those described with respect to PECO Exhibit MJT-1, Schedule C-5, except that the pension asset balance for the FTY reflects data through December 31, 2026, which, on a net aggregate basis, is $34.3 million, as shown on line 7.

108. Q. Please describe the calculations on Schedule C-6.

A. These calculations show the ADIT for the FTY. The procedures followed to determine FTY ADIT were the same as those utilized for the ADIT calculation at the end of the FPFTY except that year-end December 31, 2026 balances were used. The resulting ADIT of $261.8 million for the total of gas distribution utility plant and the gas distribution portion of the common plant for the FTY is shown on line 13. As shown on Schedule C-12, line 9, $107.4 million of excess ADIT has been removed from the ADIT balance and recorded as a regulatory liability.

109. Q. Please describe the data presented on Schedules C-7, C-9, C-11 and C-13.

A. The data on these four schedules are the same as the data presented and described in connection with the comparable schedules in PECO Exhibit MJT-1, since the same 13-month period was used.

110. Q. What is shown on Schedule C-8?

A. This schedule shows the common plant, net of accumulated depreciation, included in the measures of value on Schedule A-1 for the FTY.

111. Q. What is presented on Schedule D-1?

A. Schedule D-1 shows the net operating income at present rates for the FTY, the pro forma revenue deficiency, and the pro forma required revenue level.

112. Q. Please describe Schedule D-2.

A. Schedule D-2 shows revenues and expenses budgeted for the FTY, pro forma adjustments, and the pro forma revenue and expense amounts at present rates. This schedule summarizes the adjustments that are detailed on Schedules D-3 and D-5 and explained in connection with other supporting schedules to be described later in my testimony.

113. Q. Please describe Schedule D-3.

A. Schedule D-3 contains six pages, which present a summary of each of the pro forma adjustments made to revenues and operating expenses, including depreciation and taxes-other-than-income taxes. Each of the adjustments will be described in connection with the specific schedule containing the calculation of the adjustment.

114. Q. What is contained in Schedule D-4?

A. This schedule contains four pages and shows the budgeted and pro forma adjustment amounts for the FTY by revenue category and by FERC account for expenses.

115. Q. Please describe Schedule D-5.

A. Schedule D-5 shows the pro forma adjustments to the FTY budgeted revenues. Each of the listed adjustments is discussed in connection with Schedules D-5A to D-5F. All of these adjustments were prepared using the same methodology as described in connection with PECO Exhibit MJT-1.

116. Q. Please describe the adjustment shown on Schedule D-5A.

A. The adjustment shown on Schedule D-5A annualizes revenues for customer growth during the FTY. The process utilized is the same as described in connection with the same adjustment for the FPFTY on PECO Exhibit MJT-1, Schedule D-5A.

117. Q. What is the adjustment shown on Schedule D-5B?

A. The adjustment shown on Schedule D-5B annualizes CAP discounts for the FTY. The process utilized is the same as described in connection with the corresponding adjustment for the FPFTY shown on PECO Exhibit MJT-1, Schedule D-5B.

118. Q. Please describe the adjustment shown on Schedule D-5C.

A. This schedule shows the development of a normalized level of distribution revenue based on the average number of days per year in a four-year cycle.

119. Q. Please describe the adjustment shown on Schedule D-5E.

A. This adjustment eliminates revenues associated with asset optimization items.

120. Q. Please describe the adjustment shown on Schedule D-5F.

A. This schedule shows the adjustment to revenues associated with the use of a 10-year historical average to define normalized weather assumptions for sales and billing determinants in this case.

121. Q. Please describe Schedule D-6.

A. Schedule D-6 annualizes S&W for the FTY. Pages 59 and 60 show the calculation of the annualization adjustments of S&W and the normalization of the union contract ratification payment, which follow the same procedures described in connection with the FPFTY using the data from the FTY for the wage increases. Pages 61 and 62 show the budgeted amounts in column 1 and the pro forma adjustment in column 2 by FERC expense category.

122. Q. What is contained on Schedule D-7?

A. Schedule D-7 normalizes rate case expenses using the same recorded and estimated amounts used in the FPFTY calculation shown on PECO Exhibit MJT-1, Schedule D-7.

123. Q. Please describe the adjustment shown on Schedule D-8.

A. This adjustment, which annualizes non-pension benefits related to the change in number of employees during the FTY, was calculated using the same procedures used for the comparable adjustment for the FPFTY and described in connection with PECO Exhibit MJT-1, Schedule D-8.

124. Q. Please describe the adjustment shown on Schedule D-9.

A. This adjustment to pension expense follows the same procedures used for the FPFTY, which were described in connection with PECO Exhibit MJT-1, Schedule D-9.

125. Q. Are the adjustments shown on Schedules D-10 to D-15 similar to the adjustments included in PECO Exhibit MJT-1 and described in connection with the schedules presented in that exhibit?

A. Yes, they are.

126. Q. Please describe Schedule D-16.

A. Schedule D-16 shows the development of the Company's claim for taxes other than income taxes for the FTY.

127. Q. Please describe Schedule D-17.

A. Schedule D-17 presents the pro forma adjustment for depreciation to annualize depreciation expense for plant amounts at the end of the FTY, similar to the pro forma adjustment set forth in PECO Exhibit MJT-1.

128. Q. Please describe the income tax calculations on Schedule D-18.

A. This schedule shows the calculation of the pro forma income tax expense for the FTY reflecting the revenues, expenses and measures of value included in the pro forma present rate data for the Company and a 21% Federal corporate tax rate. In addition to the tax depreciation amounts, the ITC amortization was calculated, as shown on pages 83 and 84 of Schedule D-18. The flow-back of excess ADIT was reflected in calculating income tax. The total calculated income tax shown on line 56 was used in the calculation of the overall revenue requirement shown on Schedule A-1.

129. Q. Referring now to PECO Exhibit MJT-3, for the HTY, what is contained on Schedule A-1?

A. Schedule A-1 shows a summary of the measures of value on lines 1 to 14, operating revenues and expenses and calculated rates of return at present and proposed rates on lines 18 to 33, and the revenue increase required on lines 35 to 46.

130. Q. What is contained on Schedules B-1 to B-5?

A. These schedules contain recorded financial data for the HTY.

131. Q. Please describe Schedules B-6 and B-7.

A. These two schedules contain the HTY capital structure and rate of return developed by Ms. Bulkley. As shown on lines 1 to 3 of Schedule B-7, the Company is using its capital structure at the end of the HTY and cost rates as shown on Schedule B-7.

132. Q. Please describe Schedule C-1.

A. Schedule C-1 lists the measures of value components. The measures of value total for the HTY is $3.5 billion, as shown on column 4, line 14.

133. Q. What is contained in Schedule C-2?

A. Schedule C-2 consists of five pages and shows the utility plant-in-service balances on December 31, 2025 for the Company's distribution operations, as well as the adjustments for the HTY. Pages 18 and 19 contain the summary of plant-in-service balances by plant grouping. Page 15 shows the plant-in-service by FERC account. Pages 16 and 17 are left blank intentionally because they reflect schedules that are used for the FTY and FPFTY but are not relevant to the HTY. Finally, adjustments to plant are reflected on pages 18 and 19. The total plant-in-service at the end of the HTY is $4.65 billion and is shown on Schedule C-2, page 15, column 4, line 36.

134. Q. Please describe Schedule C-3.

A. Schedule C-3 contains three pages and shows the accumulated depreciation on December 31, 2025. These pages reflect the balances by FERC account for the HTY. The accumulated depreciation at the end of the HTY is $1.03 billion, as shown on page 20, column 4, line 36.

135. Q. What is contained in Schedule C-4?

A. Schedule C-4 contains nine pages that show the calculation of the CWC allowance for the HTY of $21.1 million on page 23, line 27. The information for average prepayments shown on line 23 is the same as that utilized in PECO Exhibit MJT-1 because the FPFTY claim is based on the 13-month average for the period ended December 31, 2025. In additional to the prepayments, the methodology used to calculate the lag periods for revenue, payroll, pension expense, gas purchases and other disbursements utilized in PECO Exhibit MJT-1 were also used in the HTY calculation.

Page 23 provides a summary of the calculations for each of the elements of the CWC for the HTY. The expenses in column 2 and those included in the determination of the lead-lag amounts for taxes, interest and preferred dividends are the adjusted pro forma amounts for the HTY, while the prepayment amount is the 13-month average through December 31, 2025. The resulting $21.1 million of CWC shown on line 27 is brought forward to Schedule A-1 in the calculation of the measures of value.

136. Q. Please describe what is shown on Schedule C-4, pages 24 to 31.

A. These pages show the calculations of various leads and lags and working capital requirements for the HTY following the same procedures used for the FPFTY as described in connection with PECO Exhibit MJT-1, Schedule C-4. While the amounts for the HTY expenses vary from those in the FPFTY, the procedures followed to determine the lead/lag periods applied to those expense levels are the same and were described in connection with the corresponding PECO Exhibit MJT-1 schedules.

137. Q. What is contained on Schedule C-5?

A. Schedule C-5 shows the Company's claim for a pension asset included in the measures of value. The procedures to determine the asset are the same as those described in connection with PECO Exhibit MJT-1, Schedule C-5, except that the pension asset balance for the HTY reflects data through December 31, 2025, which, on a net aggregate basis, is $34.4 million, as shown on line 5.

138. Q. Please describe the calculations shown on Schedule C-6.

A. These calculations show the ADIT for the HTY. The procedures followed to determine HTY ADIT were the same as those utilized for the ADIT calculation at the end of the FPFTY, except that 12-month ended December 31, 2025 balances were used. The resulting ADIT of $205.0 million for the total of gas distribution utility plant and the gas distribution portion of common plant for the HTY is shown on line 5. As shown on Schedule C-12, line 3, $109.0 million of excess ADIT has been removed from the ADIT balance and recorded as a regulatory liability.

139. Q. Please describe the data presented on Schedules C-7, C-9, C-11 and C-13.

A. The data on these four schedules are the same as the data presented and described in connection with the comparable schedules in PECO Exhibit MJT-1 because the same 13-month period was used.

140. Q. What is shown on Schedule C-8?

A. This schedule shows the common plant, net of accumulated depreciation, included in the measures of value on Schedule A-1 for the HTY.

141. Q. What is presented on Schedule D-1?

A. Schedule D-1 shows the net operating income at present rates for the HTY, the pro forma revenue deficiency, and the pro forma required revenue level.

142. Q. Please describe Schedule D-2.

A. Schedule D-2 shows revenues and expenses for the HTY, pro forma adjustments, and the pro forma revenue and expense amounts at present rates. This schedule summarizes the adjustments that are detailed on Schedules D-3 and D-5 and explained in connection with other supporting schedules to be described later in my testimony.

143. Q. Please describe Schedule D-3.

A. Schedule D-3 contains six pages, which present a summary of each of the pro forma adjustments made to revenues and operating expenses, including depreciation and taxes other than income taxes. Each of the adjustments will be described in connection with the specific schedule containing the calculation of the adjustment.

144. Q. What is contained in Schedule D-4?

A. This schedule contains four pages and shows the recorded amounts and pro forma adjustment amounts for the HTY by revenue category and by FERC account for expenses.

145. Q. Please describe Schedule D-5.

A. Schedule D-5 shows the pro forma adjustments to the HTY revenues. Each of the listed adjustments is discussed in connection with Schedules D-5A to D-5F. All of these adjustments were prepared using the same methodology described in connection with PECO Exhibit MJT-1, except Schedule D-5D, which is the weather normalization adjustment to distribution revenue recorded for the 12 months ended December 31, 2025.

146. Q. Please describe the adjustment shown on Schedule D-5A.

A. The adjustment shown on Schedule D-5A annualizes revenues for customer growth during the HTY. The process utilized is the same as that described in connection with the same adjustment for the FPFTY on PECO Exhibit MJT-1, Schedule D-5A.

147. Q. What is the adjustment shown on Schedule D-5B?

A. The adjustment shown on Schedule D-5B annualizes CAP discounts for the HTY. The process utilized is the same as described in connection with the corresponding adjustment for the FPFTY shown on PECO Exhibit MJT-1, Schedule D-5B.

148. Q. Please describe the adjustment on Schedule D-5C.

A. This schedule shows the development of a normalized level of distribution revenue based on average number of days per year in a four-year cycle.

149. Q. Please describe the adjustment shown on Schedule D-5D.

A. Schedule D-5D shows the adjustment to normalize HTY distribution revenue to reflect normal weather for weather sensitive load. This adjustment does not apply to the FTY and the FPFTY because the distribution revenue for both of those years was budgeted on the basis of normal weather.

150. Q. Please describe the adjustment shown on Schedule D-5E.

A. This adjustment eliminates revenues associated with the asset optimization items.

151. Q. Please describe the adjustment shown on Schedule D-5F.

A. This schedule shows the adjustment to revenues associated with the use of a 10-year historical average to define normalized weather assumptions for sales and billing determinants in this case.

152. Q. Please describe Schedule D-6.

A. Schedule D-6 annualizes S&W for the HTY. Pages 59 and 60 show the recorded amounts in column 1, and the pro forma adjustment in column 2 by FERC expense category. Pages 61 and 62 show the calculation of the annualization adjustments of S&W and the normalization of the union contract ratification payment, which follows the same procedures described in connection with the FPFTY using the data from the HTY to calculate the wage increases.

153. Q. What is contained on Schedule D-7?

A. Schedule D-7 normalizes rate case expenses using the same recorded and estimated amounts used in the FPFTY calculation shown on PECO Exhibit MJT-1, Schedule D-7.

154. Q. Please describe the adjustments shown on Schedule D-8.

A. This adjustment, which annualizes non-pension benefits related to the change in number of employees during the HTY, was calculated using the same procedures used for the comparable adjustment for the FPFTY and described in connection with PECO Exhibit MJT-1, Schedule D-8.

155. Q. Please describe the adjustment on Schedule D-9.

A. This adjustment to pension expense in the HTY follows the same procedures used for the FPFTY, which were described in connection with PECO Exhibit MJT-1, Schedule D-9.

156. Q. Are the adjustments on Schedules D-10 to D-15 similar to the adjustments included in PECO Exhibit MJT-1 and described in connection with the schedules presented in that exhibit?

A. Yes, they are.

157. Q. Please describe Schedule D-16.

A. Schedule D-16 shows the development of the Company's claim for taxes other than income taxes for the HTY.

158. Q. Please describe Schedule D-17.

A. Schedule D-17 presents the pro forma adjustment for depreciation to annualize depreciation expense for plant balances at the end of the HTY, similar to the pro forma adjustment set forth in PECO Exhibits MJT-1 and MJT-2.

159. Q. Please describe the income tax calculations on Schedule D-18.

A. This schedule shows the calculation of the pro forma income tax expense for the HTY reflecting the revenues, expenses and measures of value included in the pro forma present rate data for the Company and a 21% Federal corporate tax rate. In addition to the tax depreciation amounts, the ITC amortization was calculated as shown on pages 83 and 84 of Schedule D-18. The flow-back of excess ADIT was reflected in calculating income tax. The total calculated income tax shown on line

56 was used in the calculation of the overall revenue requirement shown on Schedule A-1.

VI. CONCLUSION

160. Does this complete your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060860**
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, Michael J. Trzaska, hereby state that I am a Principal Regulatory and Rates Specialist for PECO Energy Company; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 4 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Dated: March 30, 2026

Michael J. Trzaska

PECO Exhibit MJT-1:
Principal Accounting Exhibit FPFTY ending 2027

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2027
($ in Thousands)
A-1 Overall Summary

Line No.	Description	(1) Reference	(2) Present Rates	(3) Revenue Increase	(4) Total
1	**MEASURE OF VALUE**				
2	Utility Plant	C-2	$5,263,474		$5,263,474
3	Accumulated Depreciation	C-3	1,157,820		1,157,820
4	Common Plant - Net of Accum Depr	C-8	209,690		209,690
5	Net Plant in service	L2 - L3 + L4	$4,315,344		$4,315,344
6					
7	Working Capital	C-1	$21,663		$21,663
8	Pension Assets / (Liability)	C-1	33,911		33,911
9	Accum Deferred Income Taxes	C-1	(282,731)		(282,731)
10	Customer Deposits	C-1	(14,323)		(14,323)
11	Customer Advances for Construction	C-1	(1,400)		(1,400)
12	Materials and Supplies	C-1	608		608
13	Accum Deferred Income Taxes - Reg Liability	C-1	(103,653)		(103,653)
14	Gas Storage	C-1	32,762		32,762
15					
16	TOTAL RATE BASE	SUM L5 to L14	$4,002,182		$4,002,182
17					
18	**OPERATING REVENUES AND EXPENSES**				
19	Base Customer Charges	D-5	$560,529	$81,269	$641,798
20	Supply Cost Revenue	D-5	291,363		291,363
21	Other Operating Revenues	D-5	5,140	111	5,250
22	Total Revenues	SUM L19 to L21	$857,032	$81,380	$938,412
23					
24	Operating Expenses	D-1	$602,946	$791	$603,737
25					
26	OIBIT	L22 - L24	$254,086	$80,588	$334,674
27					
28	Income Taxes @ Eff Inc Tax Rate	D-18	$10,076		$10,076
29	Income Taxes @ Statutory Rates	D-18		(21,374)	(21,374)
30					
31	NET OPERATING INCOME	SUM L26 to L29	$264,162	$59,215	$323,376
32					
33	RATE OF RETURN	L31 / L16	6.60%		8.08%
34					
35	**REVENUE INCREASE REQUIRED**				
36	Rate of Return at Present Rates	L33	6.60%		
37					
38	Rate of Return Required	B-7	8.08%		
39					
40	Change in ROR	L38 - L36	1.48%		
41					
42	Change in Operating Income	L16 * L40	$59,215		
43					
44	Gross Revenue Conversion Factor	D-19	1.372		
45					
46	Change in Revenues	L42 * L44	$81,269		
47					
48	**RETURN ON COMMON EQUITY**				
49	Common Equity Ratio	B-7	53.40%		
50	Common Equity Rate Base	L16 * L49	$2,137,165		
51	NET OPERATING INCOME	L31	$264,162		
52	Synchronized Interest Expense	D-18	$89,249		
53	NET OPERATING INCOME - COMMON EQUITY	L51 - L52	$174,913		
54	RATE OF RETURN ON COMMON EQUITY	L53 / L50	8.18%		

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$23,169,467
3	Construction Work In Progress (107)		1,447,716
4	Total Utility Plant	SUM L2 to L3	$24,617,183
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		5,226,843
6	Net Utility Plant	L4 - L5	$19,390,340
7			
8	**Other Property and Investments**		
9	Non-utility Property (121)		$14,745
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,732
11	Invest in Assoc Company (123)		7,540
12	Other Investments (124-129, 175-176)		38,062
13	Total Other Property and Investments	SUM L9 to L12	$58,614
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments(131-136)		$25,000
17	Customer Accounts Receivable (142)		678,393
18	Other Accounts Receivable (143)		32,249
19	Accum. Prov. for Uncollectible (144)		(137,955)
20	Receivables from Assoc. Comp. (146)		
21	Fuel Stock (151)		1,710
22	Plant Materials & Supplies (154)		97,053
23	Gas Stored - Current (164.1		43,922
24	Liquefied Natural Gas stored (164.2)		3,187
25	Prepayments (165)		73,829
26	Accrued Utility Revenues (173)		324,703
27	Miscellaneous Current & Accrued Assets (174)		2,920
28	Total Current and Accrued Assets	SUM L16 to L27	$1,145,010
29			
30	**Deferred Debits**		
31	Unamortized Debt Expense (181)		$64,321
32	Other Regualtory Assets (182.3)		1,766,805
33	Miscellaneous Deferred Debits (186)		893,284
34	Unamortized Loss on Reacquired Debt (189)		487
35	Accumulated Deferred Income Taxes (190)		0
36	Total Deferred Debits	SUM L31 to L35	$2,724,897
37			
38	**Total Assets**	L6 + L13 + L28 + L36	$23,318,861

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Total - PECO
39	**Proprietary Capital**		
40	Common Stock Issued (201)		$1,423,004
41	Preferred Stock Issued (204)		
42	Other Paid-In Capital (208-211)		4,980,451
43	Capital Stock Expense (214)		(87)
44	Retained Earnings (215, 215.2, 216)		2,946,157
45	Unappropriated Undistributed Subsidiary Earnings (216.1)		
46	Accum Other Comprehensive Income (219)		
47	Total Propriety Capital & Margins	SUM L40 to L46	$9,349,525
48			
49	**Long Term Debt**		
50	Bonds (221)		$7,975,000
51	Advances from Associated Companies (223)		184,419
52	Other Long-Term Debt (224)		
53	Unamortized Premium on LTD (225)		
54	Unamortized Discount on LTD (226)		(22,573)
55	Total Long-Term Debt	SUM L50 to L54	$8,136,846
56			
57	**Other Non-Current Liabilities**		
58	Obligations under Capital Leases (227)		
59	Accum. Prov for Injuries & Damages (228.2)		$62,513
60	Accum. Prov for Pensions & Benefits (228.3)		300,379
61	Accum. Miscellaneous Operating Prov (228.4)		11,729
62	Asset Retirement Obligation (230)		25,844
63	Total Other Non-Current Liabilities	SUM L58 to L62	$400,465
64			
65	**Current and Accrued Liabilities**		
66	Notes Payable (231)		$285,689
67	Accounts Payable (232)		784,359
68	Notes Payable to Assoc. Companies (233)		
69	Accounts Payable to Assoc. Companies (234)		25,774
70	Customer Deposits (235)		93,432
71	Taxes Accrued (236)		20,830
72	Interest Accrued (237)		107,630
73	Dividends Declared (238)		
74	Tax Collections Payable (241)		86
75	Misc Current & Accrued Liabilities (242)		156,513
76	Total Current & Accrued Liabilities	SUM L66 to L75	$1,474,315
77			
78	**Other Deferred Credits**		
79	Customer Advances for Construction (252)		$15,732
80	Other Deferred Credits (253)		8,645
81	Other Regulatory Liabilities (254)		564,296
82	Deferred Investment Tax Credit (255)		244
83	Unamortized Gain on Reacquired Debt (257)		
84	Accumulated Deferred Income Taxes (281-283)		3,368,794
85	Total Other Deferred Credits	SUM L79 to L84	$3,957,711
86			
87	**Total Liabilities and Other Credits**	L47 + L55 + L63 + L76 + L85	$23,318,861

($ in Thousands)

			(1)	(2)	(3)
Line No.	Category	Description	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$578,523		$578,523
2		Gas Cost Revenue	291,363		291,363
3		Other Operating Revenues	25,140		25,140
4		Total Operating Revenues	$895,026		$895,026
5					
6	**Total Operating Expenses**	Operation & Maintenance Expenses	$473,323		$473,323
7		Depreciation & Amortization Expense	124,658		124,658
8		Amortization of Regulatory Expense	2,396		2,396
9		Taxes Other Than Income Taxes - Other	10,102		10,102
10		Total Operating Expenses	$610,479		$610,479
11					
12	**Net Utility Operating Income Before Income Tax**		$284,547		$284,547

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	480.0	$396,580		$396,580
2			C & I	481.0	147,498		147,498
3			Transportation of Gas of Others	489.3	34,445		34,445
4				Subtotal	$578,523		$578,523
5							
6		Gas Cost Revenue	Residential	480.0	$222,710		$222,710
7			C & I	481.0	68,654		68,654
8			Interdepartmental	484.0			
9				Subtotal	$291,363		$291,363
10							
11		Other Operating Revenues	Sales For Resale	483.0	$20,000		$20,000
12			Forfeited Discounts	487.0	1,314		1,314
13			Miscellaneous Service Revenues	488.0			
14			Rent for Gas Property	493.0	2,991		2,991
15			Interdepartmental Rents	494.0			
16			Other Gas Revenues	495.0	835		835
17				Subtotal	$25,140		$25,140
18							
19				**Total Operating Revenues**	$895,026		$895,026
20							
21	**Operating Expenses**	Operation & Maintenance Expenses	Manufactured Gas Production	710.0			
22			Liquefied Petroleum Gas Expenses	717.0	166		166
23			Liquefied Petroleum Gas Expenses	728.0	0		0
24			Maintenance of Structures and Improvements	741.0	110		110
25			Maintenance of Production Equipment	742.0	276		276
26			Natural Gas City Gate Purchases	804.0	306,363		306,363
27			Other Gas Purchases	805.0			
28			Purchases Gas Cost Adjustments	805.1			
29			Purchased Gas Expenses	807.0			
30			Gas Withdrawn from Storage-Debit	808.1			
31			Gas Delivered to Storage-Credit	808.2			
32			Other Gas Supply Purchases	813.0			
33			Other Expenses	824.0			
34			Operating Supervision and Engineering	840.0	449		449
35			Operation Labor and Expenses	841.0	1,091		1,091

($ in Thousands)

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FPFTY Amount	Non-Jurisdictional	Jurisdictional
36			Maintenance Supervision and Engineering	843.1	1,161		1,161
37			Maintenance of Structures and Improvements	843.2	4,501		4,501
38			Operation Supervision and Engineering	870.0	766		766
39			Mains and Services Expenses	874.0	20,557		20,557
40			Measuring and Regulating Station Expenses-General	875.0	1,296		1,296
41			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
42			Meter and House Regulator Expenses	878.0	6,090		6,090
43			Customer Installations Expenses	879.0	6,972		6,972
44			Other Expenses	880.0	19,485		19,485
45			Rents	881.0	23		23
46			Maintenance of Mains	887.0	17,668		17,668
47			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	739		739
48			Maintenance of Services	892.0	2,368		2,368
49			Maintenance of Meters & House Regulators	893.0	169		169
50			Maintenance of Other Equipment	894.0	615		615
51			Meter Reading	902.0	41		41
52			Customer Records and Collection	903.0	19,974		19,974
53			Uncollectible Accounts	904.0	2,629		2,629
54			Miscellaneous Customer Accounts	905.0	805		805
55			Customer Assistance	908.0	7,794		7,794
56			Informational & Instructional	909.0	667		667
57			Miscellaneous Customer & Informational	910.0			
58			Demonstrating & Selling	912.0	830		830
59			Miscellaneous Sales	916.0			
60			Administrative and General Salaries	920.0	7,694		7,694
61			Office Supplies and Expenses	921.0	710		710
62			Administrative Expenses Transferred-Credit	922.0			
63			Outside Service Employed	923.0	22,293		22,293
64			Property Insurance	924.0	209		209
65			Franchise Requirements	925.0	4,343		4,343
66			Employee Pensions and Benefits	926.0	10,037		10,037
67			Regulatory Commission Expenses	928.0	2,636		2,636
68			Duplicate Charges-Credit	929.0	(8)		(8)
69			Miscellaneous General Expenses	930.2	853		853
70			Maintenance of General Plant	932.0	951		951

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
71				Subtotal	$473,323		$473,323
72							
73			Depreciation & Amortization Expense	403.0	$109,074		$109,074
74				403.1			
75				404.0	15,584		15,584
76				Subtotal	$124,658		$124,658
77							
78			Amortization of Regulatory Expense	407.3	$2,396		$2,396
79				Subtotal	$2,396		$2,396
80							
81			Taxes Other Than Income Taxes - Other	408.1	$10,102		$10,102
82				Subtotal	$10,102		$10,102
83							
84				**Total Operating Expenses**	$610,479		$610,479
85							
86				**Net Utility Operating Income Before Income Tax**	$284,547		284,547

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) FPFTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	480.0	$396,580		$396,580
2			C & I	481.0	147,498		147,498
3			Transportation of Gas of Others	489.3	34,445		34,445
4				Subtotal	$578,523		$578,523
5							
6		**Gas Cost Revenue**	Residential	480.0	$222,710		$222,710
7			C & I	481.0	68,654		68,654
8			Interdepartmental	484.0			
9				Subtotal	$291,363		$291,363
10							
11			OPERATING REVENUE		$869,886		$869,886
12							
13	**OTHER REVENUE**	**Other Operating Revenue**	Sales For Resale	483.0	$20,000		$20,000
14			Forfeited Discounts	487.0	$1,314		1,314
15			Miscellaneous Service Revenues	488.0			
16				Subtotal	$21,314		$21,314
17							
18		**Other Gas Revenue**	Rent for Gas Property	493.0	$2,991		2,991
19			Interdepartmental Rents	494.0			
20			Other Gas Revenues	495.0	835		835
21				Subtotal	$3,825		$3,825
22							
23			OTHER REVENUE		$25,140		$25,140
24							
25			OTHER OPERATING REVENUES				
26							
27			**TOTAL**		**$895,026**		**$895,026**

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) Budget FPFTY	(2) Non-Jurisdictional	(3) Jurisdictional
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	Manufactured Gas Production	Manufactured Gas Production	710.0			
2			Liquefied Petroleum Gas Expenses	717.0	$166		$166
3			Maintenance of Structures and Improvements	741.0	110		110
4			Maintenance of Production Equipment	742.0	276		276
5				SUM L1 to L4	$552		$552
6							
7	**GAS RAW MATERIALS**	Gas Raw Materials	Liquefied Petroleum Gas Expenses	728.0	0		0
8							
9	**OTHER GAS SUPPLY EXPENSES**	Other Gas Supply	Natural Gas City Gate Purchases	804.0	$306,363		$306,363
10			Other Gas Purchases	805.0			
11			Purchases Gas Cost Adjustments	805.1			
12			Purchased Gas Expenses	807.0			
13			Gas Withdrawn from Storage-Debit	808.1			
14			Gas Delivered to Storage-Credit	808.2			
15			Other Gas Supply Purchases	813.0			
16				SUM L9 to L15	$306,363		$306,363
17							
18	**UNDERGROUND STORAGE EXPENSES**	Underground Storage Expenses	Other Expenses	824.0			
19							
20	**STORAGE EXPENSE**	Storage Operations Expense	Operating Supervision and Engineering	840.0	$449		$449
21			Operation Labor and Expenses	841.0	1,091		1,091
22				SUM L20 to L21	$1,540		$1,540
23							
24		Storage Maintenance Expense	Maintenance Supervision and Engineering	843.1	$1,161		$1,161
25			Maintenance of Structures and Improvements	843.2	4,501		4,501
26				SUM L24 to L25	$5,662		$5,662
27							
28			Subtotal STORAGE EXPENSE	L22 + L26	$7,202		$7,202
29							
30	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation Supervision and Engineering	870.0	$766		$766
31			Mains and Services Expenses	874.0	20,557		20,557
32			Measuring and Regulating Station Expenses-General	875.0	1,296		1,296
33			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
34			Meter and House Regulator Expenses	878.0	6,090		6,090
35			Customer Installations Expenses	879.0	6,972		6,972
36			Other Expenses	880.0	19,485		19,485
37			Rents	881.0	23		23
38				SUM L30 to L37	$55,190		$55,190
39							
40		Distribution Maintenance	Maintenance of Mains	887.0	$17,668		$17,668
41			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	739		739
42			Maintenance of Services	892.0	2,368		2,368
43			Maintenance of Meters & House Regulators	893.0	169		169
44			Maintenance of Other Equipment	894.0	615		615
45				SUM L40 to L44	$21,559		$21,559

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) Budget FPFTY	(2) Non-Jurisdictional	(3) Jurisdictional
46							
47			Subtotal DISTRIBUTION EXPENSE	L38 + L45	$76,749		$76,749
48							
49	**CUSTOMER ACCOUNTS**	Customer Accounts	Meter Reading	902.0	$41		$41
50			Customer Records and Collection	903.0	19,974		19,974
51			Uncollectible Accounts	904.0	2,629		2,629
52			Miscellaneous Customer Accounts	905.0	805		805
53			Subtotal CUSTOMER ACCOUNTS	SUM L49 to L52	$23,449		$23,449
54							
55	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$7,794		$7,794
56			Informational & Instructional	909.0	667		667
57			Miscellaneous Customer & Informational	910.0			
58			Subtotal CUSTOMER SERVICE & INFORMATION	SUM L55 to L57	$8,461		$8,461
59							
60	**SALES**	Sales	Demonstrating & Selling	912.0	$830		$830
61			Miscellaneous Sales	916.0			
62			Subtotal SALES	SUM L60 to L61	$830		$830
63							
64	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$7,694		$7,694
65			Office Supplies and Expenses	921.0	710		710
66			Administrative Expenses Transferred-Credit	922.0			
67			Outside Service Employed	923.0	22,293		22,293
68			Property Insurance	924.0	209		209
69			Injuries & Damages	925.0	4,343		4,343
70			Employee Pensions and Benefits	926.0	10,037		10,037
71			Regulatory Commission Expenses	928.0	2,636		2,636
72			Duplicate Charges-Credit	929.0	(8)		(8)
73			Miscellaneous General Expenses	930.2	853		853
74				SUM L64 to L73	$48,766		$48,766
75							
76		A&G Maintenance	Maintenance of General Plant	932.0	$951		$951
77							
78			Subtotal ADMINISTRATION & GENERAL	L74 + L76	$49,716		$49,716
79							
80			**Total**	.ines 5+10+16+28+47+53+58+62+78	$473,323		$473,323
81							
82			Total Operations Expense		$444,765		$444,765
83			Total Maintenance Expense		28,558		28,558
84			**Total O&M Expense**	L82 + L83	$473,323		$473,323

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2027
($ in Thousands)
B-5 Taxes Detail

Line No.	Description	(1) Total	(2) Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,383	$2,383
2	Capital Stock & Franchise Tax		
3	Use Tax Accrued	817	817
4	Real Estate Tax Accrual	2,182	2,182
5	Miscellaneous TOTI		
6	Payroll Tax Accrued	4,720	4,889
7	**Total**	$10,102	$10,270

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effective Interest Rate	Average Weighted Cost Rate	Annualized Cost
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $575 - 4.90% - Due 6-15-2033		$575,000		5.03%		
2					7.05%		0.35%	
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		75,000		6.00%		
4					0.92%		0.06%	
5		PECO - FMB - $525 -4.875% - Due 9-15-2035		525,000		5.00%		
6					6.43%		0.32%	
7		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
8					3.68%		0.22%	
9		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
10					2.15%		0.12%	
11		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
12					3.06%		0.15%	
13		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.23%		
14					3.68%		0.16%	
15		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
16					3.98%		0.15%	
17		PECO - FMB - $325 - 3.90% - Due 3-1-2048		325,000		3.99%		
18					3.98%		0.16%	
19		PECO - FMB - $325 - 3.90% - Due 9-15-2048		325,000		4.17%		
20					3.98%		0.17%	
21		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
22					3.98%		0.12%	
23		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
24					4.29%		0.12%	
25		PECO - FMB - $375 - 3.05% - Due 3-1-2051		375,000		3.11%		
26					4.60%		0.14%	
27		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.91%		
28					4.60%		0.13%	
29		PECO - FMB - $350 - 4.60% - Due 6-1-2052		350,000		4.71%		
30					4.29%		0.20%	
31		PECO - FMB - $425 - 4.375% - Due 9-1-2052		425,000		4.46%		
32					5.21%		0.23%	
33		PECO - FMB - $575 - 5.25% - Due 9-15-54		575,000		5.34%		
34					7.05%		0.38%	
35		PECO - FMB - $525 - 5.65% - Due 9-15-55		525,000		5.72%		
36					6.43%		0.37%	
37		PECO - FMB - $750 - 5.80% - Due 8-1-56		750,000		5.87%		
38					9.19%		0.54%	
39		PECO - FMB - $750 - 5.90% - Due 8-1-57		750,000		5.97%		
40					9.19%		0.55%	
41								
42		Sub-Total Mortgage Bonds	SUM L1 to L40	$7,975,000	97.74%		4.64%	
43								
44	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.50%		
45					0.99%		0.07%	
46		PECO - TOPRS - $0.8 - Var (8.75%) - Due 4-6-2028		805		8.75%		
47					0.01%			
48		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
49					1.26%		0.07%	
50								
51		Sub-Total Capital Securities	SUM L44 to L49	$184,419	2.26%		0.14%	
52								
53		Total Long-Term Debt	L42 + L51	$8,159,419	100.00%		4.78%	
54								
55		Adjustments for Tenders & Calls		453				
56								
57		Net Long-Term Debt	L53 + L55	$8,159,419				
58								
59		Annualized Cost		390,020				
60								
61		Adjustment for Tenders & Calls Reacquired		68				
62								
63		**Total**	L59 + L61	$390,088				**4.78%**

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Capitalization	Capitalization Ratio	Embedded Cost	Return %
1					
2	Long-Term Debt	$8,159,419	46.60%	4.78%	2.23%
3					
4	Common Equity	9,349,525	53.40%	10.95%	5.85%
5					
6	Total	$17,508,944	100.00%		8.08%

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	Utility Plant	C-2	$5,263,474		$5,263,474
2	Accumulated Depreciation	C-3	1,157,820		1,157,820
3	Common Plant	C-8	209,690		209,690
4	**Net Plant in Service**	L1 - L2 + L3	$4,315,344		$4,315,344
5					
6	Working Capital	C-4	$21,663		$21,663
7	Pension Assets / (Liability)	C-5	33,911		33,911
8	Accumulated Deferred Income Taxes	C-6	(282,731)		(282,731)
9	Customer Deposits	C-7	(14,323)		(14,323)
10	Customer Advances for Construction	C-9	(1,400)		(1,400)
11	Material & Supplies	C-11	608		608
12	ADIT - Reg Liability	C-12	(103,653)		(103,653)
13	Gas Storage	C-13	32,762		32,762
14	**Total Measures of Value**	SUM L4 to L13	$4,002,182		$4,002,182

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents		$50		$50
2		G303 - Intangible Property		40,885		40,885
3		Subtotal	SUM L1 to L2	$40,935		$40,935
4						
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements		$1,225		$1,225
6		G311 - Liquefied Petroleum Gas Equip.		14,452		14,452
7		Subtotal	SUM L5 to L6	$15,677		$15,677
8						
9	**Other Storage Plant**	G360 - Land and Land Rights		$16		$16
10		G361 - Structures & Improvements		15,086		15,086
11		G362 - Gas Holders		7,084		7,084
12		G363 - Gas Storage Equipment		142,968		142,968
13		Subtotal	SUM L9 to L12	$165,154		$165,154
14						
15	**Distribution Plant**	G374 - Land and Land Rights		$5,809		$5,809
16		G375 - Structures and Improvements		34,929		34,929
17		G376 - Gas Mains		2,809,457		2,809,457
18		G378 - Measure & Regulate Sta Equip		36,887		36,887
19		G379 - City Gate Station		116,849		116,849
20		G380 - Services		1,485,337		1,485,337
21		G381 - Meters		188,683		188,683
22		G382 - Meter Installations		313,280		313,280
23		G387 - Other Equipment		2,598		2,598
24		G388 - ARO Costs Distribution Plt		(244)	-	(244)
25		Subtotal	SUM L15 to L24	$4,993,584		$4,993,584
26						
27	**General Plant**	G390 - Structures & Improvements		$11,386		$11,386
28		G391 - Office Furniture & Equipment		4,574		4,574
29		G394 - Tools, Shop & Garage Equip		25,126		25,126
30		G395 - Laboratory Equipment		38		38
31		G397 - Communication Equipment		6,828		6,828
32		G398 - Miscellaneous Equipment		127		127
33		G399.1 - ARO Costs General Plt		45		45
34		Subtotal	SUM L27 to L33	$48,124		$48,124
35						
36		**Total**	Lines 3+7+13+25+34	**$5,263,474**		**$5,263,474**

($ in Thousands)

Line No.	Category	Account	(1) Additions to Plant
1	**Intangible Plant**	G303 - Intangible Property	$837
2		Subtotal Intangible Plant	$837
3			
4	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	18,586
12		Subtotal Other Storage Plant	$18,586
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	3,775
16		G376 - Gas Mains	194,724
17		G378 - Measure & Regulate Station Equipment	2,375
18		G379 - City Gate Station	6,487
19		G380 - Services	69,330
20		G381 - Meters	5,090
21		G382 - Meter Installations	13,349
22		G387 - Other Equipment	-
23		Subtotal Distribution Plant	$295,129
24			
25	**General Plant**	G390 - Structures & Improvements	$352
26		G391 - Office Furniture & Equipment	856
27		G394 - Tools, Shop & Garage Equipment	2,267
28		G395 - Laboratory Equipment	-
29		G397 - Communication Equipment	441
30		G398 - Miscellaneous Equipment	
31		Subtotal General Plant	$3,916
32			
33		Total	**$318,468**

($ in Thousands)

Line No.	Category	Account	(1) Plant Retirements
1	**Intangible Plant**	G303 - Intangible Property	($5,470)
2		Subtotal Intangible Plant	($5,470)
3			
4	**Manufactured Gas Pro**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	($53)
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	(1,720)
12		Subtotal Other Storage Plant	($1,774)
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	($54)
16		G376 - Gas Mains	(8,743)
17		G378 - Measure & Regulate Station Equipment	(114)
18		G379 - City Gate Station	-
19		G380 - Services	(4,439)
20		G381 - Meters	(233)
21		G382 - Meter Installations	(1,024)
22		G387 - Other Equipment	(42)
23		G388 - ARO Costs Distribution Plant	
24		Subtotal Distribution Plant	($14,648)
25			
26	**General Plant**	G390 - Structures & Improvements	($1)
27		G391 - Office Furniture & Equipment	(463)
28		G394 - Tools, Shop & Garage Equipment	(207)
29		G397 - Communication Equipment	(204)
30		G398 - Miscellaneous Equipment	-
31		G399.1 - ARO Costs General Plant	-
32		Subtotal General Plant	($875)
33			
34		Total	**($22,767)**

($ in Thousands)

Line No.	Description	Account	(1) FPFTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
1	**Intangible Plant**	G302 - Franchises & Consents	$50	100.00%	$50	100.00%	$50	
2			$50		$50		$50	
3								
4		G303 - Intangible Property	$40,885	100.00%	$40,885	100.00%	$40,885	
5			$40,885		$40,885		$40,885	
6								
7		Subtotal	**$40,935**		**$40,935**		**$40,935**	
8								
9	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$1,225	100.00%	$1,225	100.00%	$1,225	
10			$1,225		$1,225		$1,225	
11								
12		G311 - Liquefied Petroleum Gas Equip	$14,452	100.00%	$14,452	100.00%	$14,452	
13			$14,452		$14,452		$14,452	
14								
15		Subtotal	**$15,677**		**$15,677**		**$15,677**	
16								
17	**Other Storage Plant**	G360 - Land and Land Rights	$16	100.00%	$16	100.00%	$16	
18			$16		$16		$16	
19								
20		G361 - Structures & Improvements	$15,086	100.00%	$15,086	100.00%	$15,086	
21			$15,086		$15,086		$15,086	
22								
23		G362 - Gas Holders	$7,084	100.00%	$7,084	100.00%	$7,084	
24			$7,084		$7,084		$7,084	
25								
26		G363 - Gas Storage Equipment	$142,968	100.00%	$142,968	100.00%	$142,968	
27			$142,968		$142,968		$142,968	
28								
29		Subtotal	**$165,154**		**$165,154**		**$165,154**	
30								
31	**Distribution Plant**	G374 - Land and Land Rights	$5,809	100.00%	$5,809	100.00%	$5,809	
32			$5,809		$5,809		$5,809	
33								
34		G375 - Structures and Improvements	$34,929	100.00%	$34,929	100.00%	$34,929	
35			$34,929		$34,929		$34,929	
36								
37		G376 - Gas Mains	$2,809,457	100.00%	$2,809,457	100.00%	$2,809,457	
38			$2,809,457		$2,809,457		$2,809,457	
39								
40		G378 - Measure & Regulate Sta Equip	$36,887	100.00%	$36,887	100.00%	$36,887	
41			$36,887		$36,887		$36,887	
42								
43		G379 - City Gate Station	$116,849	100.00%	$116,849	100.00%	$116,849	
44			$116,849		$116,849		$116,849	
45								
46		G380 - Services	$1,485,337	100.00%	$1,485,337	100.00%	$1,485,337	
47			$1,485,337		$1,485,337		$1,485,337	
48								
49		G381 - Meters	$188,683	100.00%	$188,683	100.00%	$188,683	
50			$188,683		$188,683		$188,683	
51								
52		G382 - Meter Installations	$313,280	100.00%	$313,280	100.00%	$313,280	
53			$313,280		$313,280		$313,280	
54								
55		G387 - Other Equipment	$2,598	100.00%	$2,598	100.00%	$2,598	
56			$2,598		$2,598		$2,598	
57								
58		G388 - ARO Costs Distribution Plant	($244)	100.00%	($244)	100.00%	($244)	

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FPFTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
59			($244)		($244)		($244)	
60								
61		Subtotal	**$4,993,584**		**$4,993,584**		**$4,993,584**	
62								
63	**General Plant**	G390 - Structures & Improvements	$11,386	100.00%	$11,386	100.00%	$11,386	
64			$11,386		$11,386		$11,386	
65								
66		G391 - Office Furniture & Equipment	$4,574	100.00%	$4,574	100.00%	$4,574	
67			$4,574		$4,574		$4,574	
68								
69		G394 - Tools, Shop & Garage Equip	$25,126	100.00%	$25,126	100.00%	$25,126	
70			$25,126		$25,126		$25,126	
71								
72		G395 - Laboratory Equipment	$38	100.00%	38	100.00%	38	
73			38		38		38	
74								
75		G397 - Communication Equipment	$6,828	100.00%	$6,828	100.00%	$6,828	
76			$6,828		$6,828		$6,828	
77								
78		G398 - Miscellaneous Equipment	$127	100.00%	$127	100.00%	$127	
79			$127		$127		$127	
80								
81		G399.1 - ARO Costs General Plant	$45	100.00%	$45	100.00%	$45	
82			$45		$45		$45	
83								
84		Subtotal	**$48,124**		**$48,124**		**$48,124**	
85								
86								
87		**Total**	**$5,263,474**		**$5,263,474**		**$5,263,474**	

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	FPFTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents				
2		G303 - Intangible Property		$16,803		$16,803
3		Subtotal Intangible Plant	SUM L1 to L2	$16,803		$16,803
4						
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements		$1,005		$1,005
6		G311 - Liquefied Petroleum Gas Equipment		13,354		13,354
7		Subtotal Manufactured Gas Production Plant	SUM L5 to L6	$14,358		$14,358
8						
9	**Other Storage Plant**	G360 - Land and Land Rights				
10		G361 - Structures & Improvements		$8,751		$8,751
11		G362 - Gas Holders		6,933		6,933
12		G363 - Gas Storage Equipment		23,402		23,402
13		Subtotal Other Storage Plant	SUM L9 to L12	$39,086		$39,086
14						
15	**Distribution Plant**	G374 - Land and Land Rights				
16		G375 - Structures and Improvements		$7,896		7,896
17		G376 - Gas Mains		480,463		480,463
18		G378 - Measure & Regulate Station Equipment		6,870		6,870
19		G379 - City Gate Station		31,586		31,586
20		G380 - Services		359,767		359,767
21		G381 - Meters		100,335		100,335
22		G382 - Meter Installations		78,092		78,092
23		G387 - Other Equipment		1,758		1,758
24		G388 - ARO Costs Distribution Plant		629		629
25		Subtotal Distribution Plant	SUM L15 to L24	$1,067,397		$1,067,397
26						
27	**General Plant**	G390 - Structures & Improvements		$4,254		$4,254
28		G391 - Office Furniture & Equipment		1,294		1,294
29		G394 - Tools, Shop & Garage Equipment		9,224		9,224
30		G395 - Laboratory Equipment		22		22
31		G397 - Communication Equipment		5,242		5,242
32		G398 - Miscellaneous Equipment		92		92
33		G399.1 - ARO Costs General Plant		47		47
34		Subtotal General Plant	SUM L27 to L33	$20,176		$20,176
35						
36		**Total**	Lines 3+7+13+25+34	**$1,157,820**		**$1,157,820**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Category	Account	FPFTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	G302 - Franchises & Consents						
2								
3		G303 - Intangible Property	$16,803	100.00%	$16,803	100.00%	$16,803	
4								
5		Subtotal	$16,803		$16,803		$16,803	
6								
7	**Distribution Plant**	G374 - Land and Land Rights		100.00%		100.00%		
8								
9		G375 - Structures and Improvements	7,896	100.00%	7,896	100.00%	7,896	
10								
11		G376 - Gas Mains	480,463	100.00%	480,463	100.00%	480,463	
12								
13		G378 - Measure & Regulate Sta Equip	6,870	100.00%	6,870	100.00%	6,870	
14								
15		G379 - City Gate Station	31,586	100.00%	31,586	100.00%	31,586	
16								
17		G380 - Services	359,767	100.00%	359,767	100.00%	359,767	
18								
19		G381 - Meters	100,335	100.00%	100,335	100.00%	100,335	
20								
21		G382 - Meter Installations	78,092	100.00%	78,092	100.00%	78,092	
22								
23		G387 - Other Equipment	1,758	100.00%	1,758	100.00%	1,758	
24								
25		G388 - ARO Costs Distribution Plant	629	100.00%	629	100.00%	629	
26								
27		Subtotal	**$1,067,397**		**$1,067,397**		**$1,067,397**	
28								
29	**General Plant**	G390 - Structures & Improvements	$4,254	100.00%	$4,254	100.00%	$4,254	
30								
31		G391 - Office Furniture & Equipment	1,294	100.00%	1,294	100.00%	1,294	
32								
33		G394 - Tools, Shop & Garage Equip	9,224	100.00%	9,224	100.00%	9,224	
34								
35		G395 - Laboratory Equipment	22	100.00%	22	100.00%	22	
36								
37		G397 - Communication Equipment	5,242	100.00%	5,242	100.00%	5,242	
38								
39		G398 - Miscellaneous Equipment	92	100.00%	92	100.00%	92	
40								
41		G399.1 - ARO Costs General Plant	47	100.00%	47	100.00%	47	
42								
43		Subtotal	**$20,176**		**$20,176**		**$20,176**	
44								
45	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$1,005	100.00%	$1,005	100.00%	$1,005	
46								
47		G311 - Liquefied Petroleum Gas Eqp	13,354	100.00%	13,354	100.00%	13,354	
48								
49		Subtotal	**$14,358**		**$14,358**		**$14,358**	
50								
51	**Other Storage Plant**	G360 - Land and Land Rights						
52								
53		G361 - Structures & Improvements	$8,751	100.00%	$8,751	100.00%	$8,751	
54								
55		G362 - Gas Holders	6,933	100.00%	6,933	100.00%	6,933	
56								
57		G363 - Gas Storage Equipment	23,402	100.00%	23,402	100.00%	23,402	
58								
59		Subtotal	**$39,086**		**$39,086**		**$39,086**	
60								
61		**Total**	**$1,157,820**		**$1,157,820**		**$1,157,820**	

($ in Thousands)

Line No.	Category	Account	(1) Reference	(2) FPFTY Amount
1	**Gas - Production Plant**	G305 - Structures and Improvements		
2		G311 - Liquefied Petroleum Gas Equipment		
3		Subtotal Gas - Production Plant	SUM L1 to L2	
4				
5	**Gas - Storage**	G361 - Structures & Improvements		($61)
6		G363 - Gas Storage Equipment		(1,120)
7		Subtotal Gas - Storage	SUM L5 to L6	($1,182)
8				
9	**Gas - Distribution**	G374 - Land and Land Rights		
10		G375 - Structures and Improvements		($46)
11		G376 - Gas Mains		(6,282)
12		G378 - Measure & Regulate Station Equipment		(470)
13		G379 - City Gate Station		(1)
14		G380 - Services		(2,866)
15		G381 - Meters		(1)
16		G382 - Meter Installations		(3,341)
17		G387 - Other Equipment		(10)
18		Subtotal Gas - Distribution	SUM L9 to L17	($13,018)
19				
20	**Gas - General Plant**	G390 - Structures & Improvements		($9)
21		G391 - Office Furniture & Equipment		(15)
22		G394 - Tools, Shop & Garage Equipment		-
23		G397 - Communication Equipment		(21)
24		Subtotal Gas - General Plant	SUM L20 to L23	($45)
25				
26		**Total**	Lines 3+7+18+24	**($14,245)**

($ in Thousands)

Line No.	Description	Reference (1)	FPFTY Expenses (2)	(Lead)/Lag Days (3)	Dollar-Days (4)
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			53.53	
4					
5	Expense Lag				
6	Payroll (Dist Only)		$51,803	13.56	$702,580
7	Pension Expense		812	(167.00)	(135,666)
8	Commodity Purchased - Gas		291,363	30.55	8,899,771
9	Payment to Suppliers		94,341	56.21	5,302,733
10	Other Expenses		111,128	43.21	4,801,439
11	Total O&M and POR Payments	SUM L6 to L10	$549,447		$19,570,856
12					
13	O&M Expense / POR Payment Lag Days			35.62	
14					
15	Net (Lead)/Lag Days	L3 - L13		17.91	
16					
17	Days in Current Year			365	
18					
19	Operating Expenses Per Day		$1,505		
20					
21	Working Capital for O&M Expense		$26,963		
22					
23	Average Prepayments		$2,593		
24	Accrued Taxes		1,320		
25	Interest Payments		(9,213)		
26					
27	Total Working Capital Requirement	SUM L21 to L25	**$21,663**		
28					
29	Pro Forma O&M Expense		$458,095		
30	Uncollectible Expense		2,988		
31	Pro Forma Cash O&M Expense	L29 - L30	$455,107		

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	Accounts Receivable Balance End of Month	Total Monthly Billing Revenue	A/R Turnover	Days Lag
1	Annual Number of Days					365
2						
3	December		$84,688			
4	January		133,726	$147,748		
5	February		145,270	147,778		
6	March		140,858	129,848		
7	April		118,807	81,256		
8	May		90,609	47,245		
9	June		83,001	38,897		
10	July		66,268	29,357		
11	August		56,882	28,650		
12	September		51,634	31,790		
13	October		49,213	37,052		
14	November		76,323	62,417		
15	December		115,675	130,449		
16						
17	Total	SUM L3 to L15	$1,212,954	$912,486		
18						
19	Average A/R Balance		13			
20						
21	Factor		$93,304	$912,486	9.78	37.32
22						
23	Collection Days Lag					37.32
24						
25	Billing and Revenue Recording Days Lag					1.00
26						
27	Billing Lag (Average Period)	365 / 12. * 0.5				15.21
28						
29	Total Revenue Lag Days	L23 + L25 + L27				**53.53**

($ in Thousands)

Line No.	Category	Description	(1) Reference	(2) Payment Date	(3) Mid-point of Service Period	(4) Expense Amount	(5) (Lead)/Lag Days	(6) Dollar Days
1	PAYROLL	Union & Non-Union Payroll				$50,017		
2		Paid Twice Per Month					13.56	
3		Weighted Payroll Dollar Value						$678,360
4								
5		Payroll Lag	SUM L1 to L3			50,017	13.56	$678,360
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2027	7/1/2027	$10,508	$ (167.00)	($1,754,836)
12								
13		Sub-Total	SUM L7 to L11			$10,508		($1,754,836)
14								
15		Lag Days for Pension Payment					$ (167.00)	
16								
17	PURCHASE COMMODITY COSTS	Payment Lag - Payment to Suppliers					56.21	
18								
19	OTHER O & M EXPENSES	March				$15,875		$656,144
20		June				18,479		697,875
21		September				36,511		1,651,476
22		December				35,501		1,590,220
23								
24		TOTAL	SUM L19 to L22			$106,366	43.21	$4,595,716

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Months	Description	Number of CDs	Cash Disbursements	Dollar-Days	Expense Lag Days
1	March	Total Disbursements for Month	33,074	$278,546		
2		Total Disbursements for Expenses	1,922	$15,875	$656,144	41.33
3						
4	June	Total Disbursements for Month	31,793	$240,494		
5		Total Disbursements for Expenses	1,904	$18,479	$697,875	37.77
6						
7	September	Total Disbursements for Month	38,855	$305,643		
8		Total Disbursements for Expenses	1,853	$36,511	$1,651,476	45.23
9						
10	December	Total Disbursements for Month	32,848	$369,705		
11		Total Disbursements for Expenses	2,215	$35,501	$1,590,220	44.79
12	**TOTAL FOUR TEST MONTHS**					
13						
14	Total Test Month Expense Disbursement		7,894	$106,366	$4,595,716	**43.21**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Tax	Description	Payment Date	Mid Point Date	Lead/(Lag) Payment Days	Total Payment Amount	Payment Percentage	Payment Amount	Weighted Dollar Days
1	**FEDERAL INCOME TAX**	First Payment	4/15/2027	7/1/2027	77	$1,450	25.00%	$362	$27,906
2		Second Payment	6/15/2027	7/1/2027	16	1,450	25.00%	362	5,799
3		Third Payment	9/15/2027	7/1/2027	(76)	1,450	25.00%	362	(27,543)
4		Fourth Payment	12/15/2027	7/1/2027	(167)	1,450	25.00%	362	(60,523)
5		Subtotal FEDERAL INCOME TAX					100.00%	$1,450	($54,362)
6									
7	**STATE INCOME TAX**	First Payment	3/15/2027	7/1/2027	108	$244	25.00%	$61	$6,590
8		Second Payment	6/16/2027	7/1/2027	15	244	25.00%	61	915
9		Third Payment	9/15/2027	7/1/2027	(76)	244	25.00%	61	(4,637)
10		Fourth Payment	12/15/2027	7/1/2027	(167)	244	25.00%	61	(10,189)
11		Subtotal STATE INCOME TAX					100.00%	$244	($7,322)
12									
13	**PURTA**	First Payment	5/1/2027	7/1/2027	61	$2,383	100.00%	$2,383	$145,334
14		Subtotal PURTA					100.00%	$2,383	$145,334
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Subtotal PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/2/2027	7/1/2027	29	$2,182	100.00%	2,182	63,275
23		Second Payment							
24		Subtotal PA PROPERTY TAX					100.00%	2,182	63,275
25									
26	**GROSS RECEIPTS TAX**	First Payment							
27		Subtotal GROSS RECEIPTS TAX							

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Total Payment Amount	Weighted Dollar Days	Payment Lead/(Lag) Days	Revenue Lag Days	Net Payment Lead/(Lag) Days	Net Payment Lead/(Lag) Dollars Days	Average Daily Amount for Working Capital
1	FEDERAL INCOME TAX	$1,450	($54,362)	(37.50)	53.53	16.03	$23,239	$64
2	STATE INCOME TAX	$244	($7,322)	(30.00)	53.53	23.53	$5,743	$16
3	PURTA	$2,383	$145,334	61.00	53.53	114.53	$272,872	$748
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$2,182	$63,275	29.00	53.53	82.53	$180,074	$493
6	GROSS RECEIPTS TAX							

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Measures of Value at End of Test Year		$4,002,182
2	Long-Term Debt Ratio		46.60%
3	Embedded Cost of Long-Term Debt		4.78%
4	Pro Forma Interest Expense	L1 * L2 * L3	$89,148
5	Days in Current Year		365
6	Daily Amount	L4 / L5	$244
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days		53.53
9	Interest Payment Lag Days	L8 - L7	(37.72)
10	Total Interest for Working Capital	L6 * L9	**($9,213)**

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Description	Reference	AGA Membership Dues	EAP Membership Dues	Northeast Gas Assoc.	OTD Tech Development	Maintenance	IT License & Maintenance	PUC Assessment Gas	Prepaid Rent	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
1	December			$156			$23	$308	$1,335	$56	$3,449	$0	$27	$478	$172	$112	$566	
2	January			143		$130	15	219	973	39	3,449	(16)	14	498	166	232	580	
3	February			130		118	15	129	779	58	3,449	(32)	0	500	110	198	554	
4	March			117		106	15	40	584	42	2,376	150	0	503	82	439	538	
5	April			104		95	15	40	389	25	2,376	134	0	528	136	378	540	
6	May		$397	91		83	15	(50)	195	44	2,376	117	0	527	237	340	489	
7	June		397	78		71	15	(50)	0	28	1,888	100	0	530	484	302	499	
8	July		397	65		59	15	(50)	1,198	14	1,888	84	0	562	405	264	445	
9	August		91	52	$58	47	15	624	1,013	(3)	1,888	67	0	445	356	226	520	
10	September		67	39	43	35	15	624	2,128	71	2,231	50	0	471	306	188	655	
11	October		41	26	29	24	15	624	1,892	54	2,231	33	0	470	256	150	748	
12	November		15	13	14	12	15	624	1,655	39	2,231	17	0	500	318	112	748	
13	December		(24)				15	404	1,419	58	2,048	0	0	505	271	74	942	
14																		
15	Total	SUM L1 to L13	$1,382	$1,015	$144	$781	$205	$3,484	$13,558	$526	$31,883	$704	$41	$6,517	$3,299	$3,016	$7,825	
16																		
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23.02%	23.02%	23.02%	23.02%	25.48%	25.48%	25.48%	
18																		
19	Distribution Amount	L15 * L17	$1,382	$1,015	$144	$781	$205	$3,484	$13,558	$526	$7,339	$162	$9	$1,500	$841	$769	$1,994	
20																		
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																		
23	Monthly Average	L19 / L21	$106	$78	$11	$60	$16	$268	$1,043	$40	$565	$12	$1	$115	$65	$59	$153	
24																		
25	**Rate Case Amount**																	**$2,593**

Line No.	Description	Shopping Percentage (1)	Weighted Lag Days (2)	Lag Days (3)
1	Residential	56%		40.00
2	Nonresidential	44%		40.00
3	Weighted Payment Lag Days		40.00	
4				
5	Billing and Revenue Days Lag			1.00
6	Billing Lag (Average Period)			15.21
7	Total Payment Lag Days			56.21

		(1)	(2)
Line No.	Description	Reference	Pension Asset
1	Balance at End of HTY - Total		$441,490
2	Activities in FTY - Total		(1,509)
3	Activities in FPFTY - Total		(5,054)
4	Balance at End of FPFTY - Total		$434,927
5	Allocation % to Utility		18.56%
6	Utility Amount	L4 * L5	$80,722
7	Allocation % to Distribution Capital		42.01%
8	Balance at End of FPFTY - Distribution Capital	L6 * L7	$33,911

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - CIAC		($4,716)	100.00%	($4,716)	100.00%	($4,716)
2		ADIT - Common Plant		106,546	100.00%	106,546	23.02%	24,527
3		ADIT - Gas Distribution		250,622	100.00%	250,622	100.00%	250,622
4		ADIT - Corporate Alternative Minimum Tax		(65,387)	100.00%	(65,387)	100.00%	(65,387)
5		Sub-Total	SUM L1 to L4	$287,064		$287,064		$205,045
6								
7	**FTY**	DIT - CIAC		$558	100.00%	$558	100.00%	$558
8		DIT - Common Plant		(7,346)	100.00%	(7,346)	23.02%	(1,691)
9		DIT - Gas Distribution		7,891	100.00%	7,891	100.00%	7,891
10		DIT - Corporate Alternative Minimum Tax		50,027	100.00%	50,027	100.00%	50,027
11		Sub-Total	SUM L7 to L10	$51,129		$51,129		$56,784
12								
13	**FPFTY**	DIT - CIAC		$587	100.00%	$587	100.00%	$587
14		DIT - Common Plant		(3,973)	100.00%	(3,973)	23.02%	(915)
15		DIT - Gas Distribution		11,778	100.00%	11,778	100.00%	11,778
16		DIT - Corporate Alternative Minimum Tax		9,451	100.00%	9,451	100.00%	9,451
17		Sub-Total	SUM L13 to L16	$17,843		$17,843		$20,902
18								
19		**Total**	L5 + L11 + L17	$356,036		$356,036		$282,731

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Residential	Non-Residential	Total
1	December		$4,220	$8,545	$12,765
2	January		4,235	8,434	12,669
3	February		4,342	8,568	12,910
4	March		4,548	8,856	13,404
5	April		4,832	9,143	13,975
6	May		5,032	9,347	14,379
7	June		5,094	9,381	14,475
8	July		5,198	9,471	14,669
9	August		5,305	9,539	14,845
10	September		5,457	9,677	15,134
11	October		5,614	9,861	15,475
12	November		5,723	9,900	15,623
13	December		5,791	10,091	15,882
14					
15	Total	SUM L1 to L13	$65,392	$120,814	$186,205
16					
17	Average Monthly Balance	L15 / 13	$5,030	$9,293	$14,323
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$5,030
21	Small C&I				8,785
22	Large C&I				508
23	Transportation				
24					
25	Total	SUM L20 to L23			**$14,323**

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	FPFTY Amount	Allocated to Non Jurisdiction	Allocated to Jurisdiction
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$521	$156
4						
5		E303 - Misc Intangible Plant		$424,321	$329,068	$95,253
6						
7		E389 - Land and Land Rights		$6,770	$5,211	$1,559
8						
9		E390 - Structures and Improvements		$526,840	$405,561	$121,278
10		E391 - Office Furniture, Equipment		114,869	88,426	26,443
11		E392 - Transportation Equipment		253,538	195,174	58,364
12		E393 - Stores Equipment		2,519	1,939	580
13		E394 - Tools, Shop, Garage Equipmnt		2,692	2,072	620
14		E396 - Power Operated Equipment		870	670	200
15		E397 - Communication Equipment		151,896	116,930	34,967
16		E398 - Miscellaneous Equipment		479	369	110
17		E399 - Other Tangible Property				
18		E399.1 - ARO Costs General Plant		240	185	55
19		Sub Total - General Plant	SUM L9 to L18	$1,053,944	$811,326	$242,618
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,485,712	$1,146,126	$339,586
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$237,746	$183,017	$54,729
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$77,546	$59,695	$17,851
31		E391 - Office Furniture, Equipment		55,218	42,507	12,711
32		E392 - Transportation Equipment		128,597	98,994	29,603
33		E393 - Stores Equipment		619	477	143
34		E394 - Tools, Shop, Garage Equipmnt		1,401	1,078	322
35		E396 - Power Operated Equipment		381	293	88
36		E397 - Communication Equipment		62,681	48,252	14,429
37		E398 - Miscellaneous Equipment		493	380	114
38		E399 - Other Tangible Property				
39		E399.1 - ARO Costs General Plant		(408)	(314)	(94)
40		Sub Total - General Plant	SUM L30 to L39	$326,529	$251,362	$75,167
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$564,274	$434,378	$129,896
42						
43		Net Common Plant	L20 - L41	**$921,437**	**$711,747**	**$209,690**
44						
45						
46		Common Plant in Service to Utility	L20	$1,485,712	$1,146,126	$339,586
47		Common Plant Accum Depreciation to Utility	L41	564,274	434,378	129,896
48		Net Common Plant to Utility	L46 - L47	$921,437	$711,747	$209,690

($ in Thousands)

		(1)
Line No.	Description	Total FPFTY Amount
1	HTY 13-Month Average	
2	December	$964
3	January	1,037
4	February	1,033
5	March	1,043
6	April	1,198
7	May	1,270
8	June	1,295
9	July	1,436
10	August	1,480
11	September	1,480
12	October	1,981
13	November	1,974
14	December	2,014
15		
16	13-Month Total	$18,204
17		
18		
19	Average Monthly Balance	**$1,400**

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Materials & Supplies	Undistributed Stores Expense	Total
1	HTY 13-Month Average				
2	December		$552	$0	$552
3	January		577	(535)	42
4	February		559	(319)	240
5	March		588	(560)	28
6	April		602	(2,433)	(1,831)
7	May		595	(911)	(316)
8	June		952	(1,049)	(97)
9	July		965	(1,747)	(782)
10	August		856	(2,066)	(1,209)
11	September		1,438	(2,581)	(1,143)
12	October		1,396	(2,857)	(1,462)
13	November		1,423	(2,421)	(998)
14	December		1,432	0	1,432
15					
16	Total	SUM L2 to L14	$11,934	($17,478)	($5,544)
17					
18	Distribution Expense Allocation Factor		100.00%	23.02%	
19					
20	Allocation to Distribution	L16 * L18	$11,934	($4,023)	
21					
22	Average Monthly Balance	L20 / 13	**$918**	**($309)**	**$608**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - Distribution		$109,004	100.00%	$109,004	100.00%	$109,004
2		ADIT - CIAC			100.00%		100.00%	
3		Subtotal HTY	L1 + L2	109,004		109,004		109,004
4								
5	**FTY**	DIT - Distribution		($1,612)	100.00%	($1,612)	100.00%	($1,612)
6		DIT - CIAC			100.00%		100.00%	
7		Subtotal FTY	L5 + L6	($1,612)		($1,612)		($1,612)
8								
9	**FPFTY**	DIT - Distribution		($3,739)	100.00%	($3,739)	100.00%	($3,739)
10		DIT - CIAC			100.00%		100.00%	
11		Subtotal FPFTY	L9 + L10	($3,739)		($3,739)		($3,739)
12								
13		**Total**	L3 + L7 + L11	$103,653		$103,653		$103,653

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	Stored Underground	LNG	Propane Gas	Total
1	December		$31,540	$3,928	$1,527	$36,995
2	January		21,596	3,071	1,527	26,195
3	February		13,954	2,966	1,481	18,401
4	March		10,871	2,907	1,481	15,259
5	April		11,311	2,857	1,481	15,649
6	May		16,991	2,804	1,481	21,276
7	June		22,340	3,219	1,481	27,041
8	July		28,648	3,738	1,570	33,956
9	August		35,448	4,008	1,710	41,166
10	September		40,349	3,962	1,710	46,021
11	October		44,863	3,912	1,710	50,485
12	November		44,665	3,873	1,710	50,247
13	December		37,749	3,774	1,693	43,216
14						
15	Total	SUM L1 to L13	$360,324	$45,018	$20,564	$425,907
16						
17	Average Monthly Balance	L15 / 13	$27,717	$3,463	$1,582	**$32,762**

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Category	Description	Reference	Pro Forma Adjusted at Present Rates	Proposed Rate Increase	Adjusted Amounts with Proposed Rate Increase
1	**Operating Revenues**	Residential		$605,036		$605,036
2		C & I		212,703		212,703
3		Interdepartmental				
4		Sales for Resale				
5		Forfeited Discounts		1,314	111	1,425
6		Miscellaneous Service Revenues				
7		Rent For Gas Property		2,991		2,991
8		Other Gas Revenues		821		821
9		Transportation of Gas of Others		34,167		34,167
10		Revenue Increase			81,269	81,269
11		Subtotal Operating Revenues	SUM L1 to L10	$857,032	$81,380	$938,412
12						
13	**Operating Expenses**	Manufactured Gas Production		$560		$560
14		Storage Operations Expense		1,568		1,568
15		Storage Maintenance Expense		5,749		5,749
16		Underground Storage Expenses				
17		Other Gas Supply		291,363		291,363
18		Distribution Expense		75,653		75,653
19		Total Customer Accounts		24,729	425	25,154
20		Total Customer Service & Information		8,467		8,467
21		Total Sales		842		842
22		Administrative & General		49,164	366	49,530
23		O&M Expense	SUM L13 to L22	$458,095	$791	$458,886
24						
25		Depreciation & Amortization Expense		$131,715		$131,715
26		Amortization of Regulatory Expense		2,866		2,866
27		Taxes Other Than Income Taxes - Other		10,270		10,270
28		Subtotal Operating Expenses	SUM L23 to L27	$602,946	$791	$603,737
29						
30	**Net Operating Income - BIT**		L11 - L28	$254,086	$80,588	$334,674

($ in Thousands)

Line No.	Category	Description	(1) FPFTY Amount Pre Adjustments	(2) Adjustments Sub-Total	(3) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	$619,290	($14,254)	$605,036
2		C & I	216,152	(3,449)	212,703
3		Interdepartmental			
4		Sales for Resale	20,000	(20,000)	
5		Forfeited Discounts	1,314		1,314
6		Miscellaneous Service Revenues			
7		Rent For Gas Property	2,991		2,991
8		Other Gas Revenues	835	(14)	821
9		Transportation of Gas of Others	34,445	(278)	34,167
10		Revenue Increase			
11		Subtotal Operating Revenues	$895,026	($37,994)	$857,032
12					
13	**Operating Expenses**	Manufactured Gas Production	$552	$8	$560
14		Storage Operations Expense	1,540	28	1,568
15		Storage Maintenance Expense	5,662	87	5,749
16		Underground Storage Expenses			
17		Other Gas Supply	306,363	(15,000)	291,363
18		Distribution Expense	76,749	(1,096)	75,653
19		Total Customer Accounts	23,449	1,279	24,729
20		Total Customer Service & Information	8,461	6	8,467
21		Total Sales	830	12	842
22		Administrative & General	49,716	(552)	49,164
23		O&M Expense	$473,323	($15,228)	$458,095
24					
25		Depreciation & Amortization Expense	$124,658	$7,057	$131,715
26		Amortization of Regulatory Expense	2,396	470	2,866
27		Taxes Other Than Income Taxes - Other	10,102	169	10,270
28		Subtotal Operating Expenses	$610,479	($7,533)	$602,946
29					
30	**Net Operating Income - BIT**		**$284,547**	**($30,461)**	**$254,086**

($ in Thousands)

Line No.	Category	Description	Description	(1) FPFTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-5F Weather Normal Adjustment	(8) D-6 Salary & Wages	(9) D-7 Rate Case Expense	(10) D-8 Adjustments for Employee Benefits
1	**Operating Revenues**	Residential	Gas Cost	$222,710									
2			Cust & Dist	396,580	543	(200)	437			(15,034)			
3			Subtotal Residential	$619,290	$543	($200)	$437			($15,034)			
4													
5		C & I	Gas Cost	$68,654									
6			Cust & Dist	147,498	519		171			(4,138)			
7			Subtotal C & I	$216,152	$519		$171			($4,138)			
8													
9		Interdepartmental	Gas Cost										
10			Subtotal Interdepartmental										
11													
12		Sales for Resale	Sales For Resale	$20,000					(20,000)				
13			Subtotal Sales for Resale	$20,000					($20,000)				
14													
15		Forfeited Discounts	Forfeited Discounts	$1,314									
16			Subtotal Forfeited Discounts	$1,314									
17													
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues										
19			Subtotal Miscellaneous Service Revenues										
20													
21		Rent For Gas Property	Rent for Gas Property	$2,991									
22			Subtotal Rent For Gas Property	$2,991									
23													
24		Other Gas Revenues	Other Gas Revenues	$835						(14)			
25			Subtotal Other Gas Revenues	$835						($14)			
26													
27		Transportation of Gas of Others	Transportation of Gas of Others	$34,445						(278)			
28			Subtotal Transportation of Gas of Others	$34,445						($278)			
29													
30		Revenue Increase	Revenue Increase										
31			Subtotal Revenue Increase										
32													
33			**Total Operating Revenues**	**$895,026**	**$1,062**	**($200)**	**$607**		**($20,000)**	**($19,464)**			
34													
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production										
36			Liquefied Petroleum Gas Expenses	166							2		
37			Liquefied Petroleum Gas Expenses	0									
38			Maintenance of Structures and Improvements	110							2		
39			Maintenance of Production Equipment	276							4		
40			Subtotal Manufactured Gas Production	$552							$8		
41													
42		Other Gas Supply	Natural Gas City Gate Purchases	$306,363					(15,000)				
43			Other Gas Purchases										
44			Purchases Gas Cost Adjustments										
45			Purchased Gas Expenses										

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending Dec. 2027
($ in Thousands)
D-3 Adj.'s to Net Operating Income

Exhibit MJT-1
Schedule D-3
Witness: Michael J. Trzaska

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Category	Description	Description	FPFTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Leap Year Adjustment	D-5E Weather Normalization	D-5E Asset Optimization - Margin Adjustment	D-5F Weather Normal Adjustment	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits
46			Gas Withdrawn from Storage-Debit										
47			Gas Delivered to Storage-Credit										
48			Other Gas Supply Purchases										
49			Subtotal Other Gas Supply	$306,363					($15,000)				
50													
51		Storage Maintenance Expense	Maintenance Supervision and Engineering	$1,161							$20		
52			Maintenance of Structures and Improvements	4,501							67		
53			Subtotal Storage Maintenance Expense	$5,662							$87		
54													
55		Storage Operations Expense	Operating Supervision and Engineering	$449							$8		
56			Operation Labor and Expenses	1,091							20		
57			Subtotal Storage Operations Expense	$1,540							$28		
58													
59		Underground Storage Expenses	Other Expenses										
60			Subtotal Underground Storage Expenses										
61													
62		Distribution Expense	Operation Supervision and Engineering	$766							$0		
63			Mains and Services Expenses	20,557							$305		
64			Measuring and Regulating Station Expenses-General	1,296							$31		
65			Measuring and Regulating Station Expenses-City Gate	0									
66			Meter and House Regulator Expenses	6,090							$76		
67			Customer Installations Expenses	6,972							$176		
68			Other Expenses	19,485							$160		
69			Rents	23									
70			Maintenance of Mains	17,668							$280		
71			Maintenance of Measuring & Reg. Station Equip.-Genl.	739							$14		
72			Maintenance of Services	2,368							$42		
73			Maintenance of Meters & House Regulators	169							$4		
74			Maintenance of Other Equipment	615							$2		
75			Subtotal Distribution Expense	$76,749							$1,092		
76													
77		Total Customer Accounts	Customer Records and Collection	$19,974							$234		
78			Meter Reading	41									
79			Miscellaneous Customer Accounts	805							$11		
80			Uncollectible Accounts	2,629									
81			Subtotal Total Customer Accounts	$23,449							$245		
82													
83		Total Customer Service & Information	Customer Assistance	$7,794							$6		
84			Informational & Instructional	667									
85			Miscellaneous Customer & Informational										
86			Subtotal Total Customer Service & Information	$8,461							$6		
87													
88		Total Sales	Demonstrating & Selling	$830							$12		
89			Miscellaneous Sales										
90			Subtotal Total Sales	$830							$12		

($ in Thousands)

Line No.	Category	Description	Description	(1) FPFTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-5F Weather Normal Adjustment	(8) D-6 Salary & Wages	(9) D-7 Rate Case Expense	(10) D-8 Adjustments for Employee Benefits
91													
92		Administrative & General	Administrative and General Salaries	$7,694							$297		
93			Administrative Expenses Transferred-Credit										
94			Duplicate Charges-Credit	(8)									
95			Employee Pensions and Benefits	10,037									18
96			Franchise Requirements	4,343									
97			Injuries and Damages								$5		
98			Maintenance of General Plant	951							$6		
99			Miscellaneous General Expenses	853							$0		
100			Office Supplies and Expenses	710									
101			Outside Service Employed	22,293									
102			Property Insurance	209									
103			Regulatory Commission Expenses	2,636									
104			Subtotal Administrative & General	$49,716							$308		$18
105													
106			**O&M Expense**	**$473,323**					**($15,000)**		**$1,786**		**$18**
107													
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$124,658									
109			Subtotal Depreciation & Amortization Expense	$124,658									
110													
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense	$2,396									
112			Subtotal Amortization of Regulatory Expense	$2,396									
113													
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$10,102									
115			Subtotal Taxes Other Than Income Taxes - Other	$10,102									
116													
117			**Total Operating Expenses**	**$610,479**					**($15,000)**		**$1,786**		**$18**
118													
119	**Net Operating Income Before Income Tax**			**$284,547**	**$1,062**	**($200)**	**$607**		**($5,000)**	**($19,464)**	**($1,786)**		**($18)**

($ in Thousands)

Line No.	Category	Description	Description	(11) D-9 Adjustments for Pension	(12) D-10 Uncollectible Accounts	(13) D-11 Energy Efficiency	(14) D-12 Customer Deposit Interest	(15) D-13 MGP Recovery	(16) D-14 MGP Interest	(17) D-15 GPC / MFC	(18) D-16 Taxes Other Than Income	(19) D-17 Depreciation Annualization	(20) Adjustments Sub-total	(21) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Gas Cost											$222,710
2			Cust & Dist										($14,254)	382,326
3			Subtotal Residential										($14,254)	$605,036
4														
5		C & I	Gas Cost											$68,654
6			Cust & Dist										($3,449)	144,049
7			Subtotal C & I										($3,449)	$212,703
8														
9		Interdepartmental	Gas Cost											
10			Subtotal Interdepartmental											
11														
12		Sales for Resale	Sales For Resale										($20,000)	
13			Subtotal Sales for Resale										($20,000)	
14														
15		Forfeited Discounts	Forfeited Discounts											$1,314
16			Subtotal Forfeited Discounts											$1,314
17														
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues											
19			Subtotal Miscellaneous Service Revenues											
20														
21		Rent For Gas Property	Rent for Gas Property											2,991
22			Subtotal Rent For Gas Property											2,991
23														
24		Other Gas Revenues	Other Gas Revenues										($14)	$821
25			Subtotal Other Gas Revenues										($14)	$821
26														
27		Transportation of Gas of Others	Transportation of Gas of Others										($278)	$34,167
28			Subtotal Transportation of Gas of Others										($278)	$34,167
29														
30		Revenue Increase	Revenue Increase											
31			Subtotal Revenue Increase											
32														
33			**Total Operating Revenues**										**($37,994)**	**$857,032**
34														
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production											
36			Liquefied Petroleum Gas Expenses										$2	168
37			Liquefied Petroleum Gas Expenses											0
38			Maintenance of Structures and Improvements										$2	112
39			Maintenance of Production Equipment										$4	280
40			Subtotal Manufactured Gas Production										$8	$560
41														
42		Other Gas Supply	Natural Gas City Gate Purchases										($15,000)	$291,363
43			Other Gas Purchases											
44			Purchases Gas Cost Adjustments											
45			Purchased Gas Expenses											

($ in Thousands)

Line No.	Category	Description	Description	(11) D-9 Adjustments for Pension	(12) D-10 Uncollectible Accounts	(13) D-11 Energy Efficiency	(14) D-12 Customer Deposit Interest	(15) D-13 MGP Recovery	(16) D-14 MGP Interest	(17) D-15 GPC / MFC	(18) D-16 Taxes Other Than Income	(19) D-17 Depreciation Annualization	(20) Adjustments Sub-total	(21) Pro Forma Adjusted at Present Rates
46			Gas Withdrawn from Storage-Debit											
47			Gas Delivered to Storage-Credit											
48			Other Gas Supply Purchases											
49			Subtotal Other Gas Supply										($15,000)	$291,363
50														
51		Storage Maintenance Expense	Maintenance Supervision and Engineering										$20	$1,181
52			Maintenance of Structures and Improvements										$67	4,568
53			Subtotal Storage Maintenance Expense										$87	$5,749
54														
55		Storage Operations Expense	Operating Supervision and Engineering										$8	$457
56			Operation Labor and Expenses										$20	1,111
57			Subtotal Storage Operations Expense										$28	$1,568
58														
59		Underground Storage Expenses	Other Expenses											
60			Subtotal Underground Storage Expenses											
61														
62		Distribution Expense	Operation Supervision and Engineering										$0	$767
63			Mains and Services Expenses										$305	20,862
64			Measuring and Regulating Station Expenses-General										$31	1,327
65			Measuring and Regulating Station Expenses-City Gate											0
66			Meter and House Regulator Expenses										$76	6,166
67			Customer Installations Expenses										$176	7,149
68			Other Expenses							(2,188)			($2,028)	17,457
69			Rents											23
70			Maintenance of Mains										$280	17,948
71			Maintenance of Measuring & Reg. Station Equip.-Genl.										$14	753
72			Maintenance of Services										$42	2,410
73			Maintenance of Meters & House Regulators										$4	173
74			Maintenance of Other Equipment										$2	618
75			Subtotal Distribution Expense							($2,188)			($1,096)	$75,653
76														
77		Total Customer Accounts	Customer Records and Collection										$234	$20,209
78			Meter Reading											41
79			Miscellaneous Customer Accounts				684		($10)				$685	1,491
80			Uncollectible Accounts		2,321					(1,961)			$360	2,988
81			Subtotal Total Customer Accounts		$2,321		$684		($10)	($1,961)			$1,279	$24,729
82														
83		Total Customer Service & Information	Customer Assistance										$6	$7,800
84			Informational & Instructional											667
85			Miscellaneous Customer & Informational											
86			Subtotal Total Customer Service & Information										$6	$8,467
87														
88		Total Sales	Demonstrating & Selling										$12	$842
89			Miscellaneous Sales											
90			Subtotal Total Sales										$12	$842

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending Dec. 2027
($ in Thousands)
D-3 Adj.'s to Net Operating Income

				(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Line No.	Category	Description	Description	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 Energy Efficiency	D-12 Customer Deposit Interest	D-13 MGP Recovery	D-14 MGP Interest	D-15 GPC / MFC	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
91														
92		Administrative & General	Administrative and General Salaries										$297	$7,991
93			Administrative Expenses Transferred-Credit											
94			Duplicate Charges-Credit											(8)
95			Employee Pensions and Benefits	(878)									($860)	9,177
96			Franchise Requirements											4,343
97			Injuries and Damages										$5	5
98			Maintenance of General Plant										$6	957
99			Miscellaneous General Expenses										$0	853
100			Office Supplies and Expenses											710
101			Outside Service Employed											22,293
102			Property Insurance											209
103			Regulatory Commission Expenses											2,636
104			Subtotal Administrative & General	($878)									($552)	$49,164
105														
106			**O&M Expense**	**($878)**	**$2,321**		**$684**		**($10)**	**($4,149)**			**($15,228)**	**$458,095**
107														
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense									$7,057	$7,057	$131,715
109			Subtotal Depreciation & Amortization Expense									$7,057	$7,057	$131,715
110														
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense			$438		$32					$470	$2,866
112			Subtotal Amortization of Regulatory Expense			$438		$32					$470	$2,866
113														
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other								$169		$169	$10,270
115			Subtotal Taxes Other Than Income Taxes - Other								$169		$169	$10,270
116														
117			**Total Operating Expenses**	**($878)**	**$2,321**	**$438**	**$684**	**$32**	**($10)**	**($4,149)**	**$169**	**$7,057**	**($7,533)**	**$602,946**
118														
119	**Net Operating Income Before Income Tax**			**$878**	**($2,321)**	**($438)**	**($684)**	**($32)**	**$10**	**$4,149**	**($169)**	**($7,057)**	**($30,461)**	**$254,086**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2027
($ in Thousands)
D-4 Expense Adjustment Summary

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Category	Description	Account	FPFTY Amount Pre Adjustments	D-5E Asset Optimization - Margin Adjustment	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 Energy Efficiency
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.								
2			717.0 Liquefied Petroleum Gas Expenses.	166		2					
3			741.0 Maintenance Of Structures And Improvements.	110		2					
4			742.0 Maintenance Of Production Equipment.	276		4					
5			Subtotal	$552		$8					
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.	0							
8			Subtotal	$0							
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.	$306,363	($15,000)						
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								
13			807.0 Purchased Gas Expenses.								
14			808.1 Gas Withdrawn From Storage-Debit.								
15			808.2 Gas Delivered To Storage-Credit.								
16			813.0 Other Gas Supply Expenses.								
17			Subtotal	$306,363	($15,000)						
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.	$449		$8					
23			841.0 Operation Labor And Expenses.	1,091		20					
24			Subtotal	$1,540		$28					
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.	$1,161		$20					
27			843.2 Maintenance Of Structures And Improvements.	4,501		67					
28			Subtotal	$5,662		$87					
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.	$766		$0					
31			874.0 Mains And Services Expenses.	20,557		305					
32			875.0 Measuring And Regulating Station Expenses--General.	1,296		31					
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.	0							
34			878.0 Meter And House Regulator Expenses.	6,090		76					
35			879.0 Customer Installations Expenses.	6,972		176					
36			880.0 Other Expenses.	19,485		160					
37			881.0 Rents.	23							
38			Subtotal	$55,190		$749					
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.	$17,668		$280					
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	739		14					
42			892.0 Maintenance Of Services.	2,368		42					
43			893.0 Maintenance Of Meters And House Regulators.	169		4					
44			894.0 Maintenance Of Other Equipment.	615		2					
45			Subtotal	$21,559		$343					
46											
47			Distribution Expense Subtotal	$76,749		$1,092					
48											

($ in Thousands)

Line No.	Category	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5E Asset Optimization - Margin Adjustment	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 Energy Efficiency
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.	$41		$0					
50			903.0 Customer Records And Collection Expenses.	19,974		234					
51			904.0 Uncollectible Accounts.	2,629						2,321	
52			905.0 Miscellaneous Customer Accounts Expenses.	805		11					
53											
54			Subtotal	$23,449		$245				$2,321	
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses	$7,794		$6					
57			909.0 Informational And Instructional Advertising Expenses.	667							
58			910.0 Miscellaneous Customer Service And Informational Expenses.								
59			Subtotal	$8,461		$6					
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.	$830		$12					
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal	$830		$12					
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.	$7,694		$297					
66			921.0 Office Supplies And Expenses.	710							
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.	22,293							
69			924.0 Property Insurance.	209							
70			925.0 Injuries And Damages.	4,343		5					
71			926.0 Employee Pensions And Benefits.	10,037				18	(878)		
72			928.0 Regulatory Commission Expenses.	2,636							
73			929.0 Duplicate Charges--Credit.	(8)							
74			930.2 Miscellaneous General Expenses.	853		0					
75											
76			Subtotal	$48,766		$302		$18	($878)		
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.	$951		$6					
79			Subtotal	$951		$6					
80											
81			A&G Expense Sub-total	$49,716		$308		$18	($878)		
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$109,074							
84			403.1 Depreciation Expense - ARO/FIN-47								
85			404.0 Amort. Of Limited-Term Plant	15,584							
86			Subtotal	$124,658							
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.	$2,396							$438
89			Subtotal	$2,396							$438
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$10,102							
92			Subtotal	$10,102							
93											
94			**Total**	**$610,479**	**($15,000)**	**$1,786**		**$18**	**($878)**	**$2,321**	**$438**

($ in Thousands)

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.								
2			717.0 Liquefied Petroleum Gas Expenses.							2	168
3			741.0 Maintenance Of Structures And Improvements.							2	112
4			742.0 Maintenance Of Production Equipment.							4	280
5			Subtotal							$8	$559
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.								0
8			Subtotal								$0
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.							($15,000)	$291,363
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								
13			807.0 Purchased Gas Expenses.								
14			808.1 Gas Withdrawn From Storage-Debit.								
15			808.2 Gas Delivered To Storage-Credit.								
16			813.0 Other Gas Supply Expenses.								
17			Subtotal							($15,000)	$291,363
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.							$8	$457
23			841.0 Operation Labor And Expenses.							20	1,111
24			Subtotal							$28	$1,568
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.							$20	$1,181
27			843.2 Maintenance Of Structures And Improvements.							67	4,568
28			Subtotal							$87	$5,749
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.							$0	$767
31			874.0 Mains And Services Expenses.							305	20,862
32			875.0 Measuring And Regulating Station Expenses--General.							31	1,327
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.								0
34			878.0 Meter And House Regulator Expenses.							76	6,166
35			879.0 Customer Installations Expenses.							176	7,149
36			880.0 Other Expenses.				(2,188)			(2,028)	17,457
37			881.0 Rents.								23
38			Subtotal				($2,188)			($1,439)	$53,751
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.							$280	$17,948
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.							14	753
42			892.0 Maintenance Of Services.							42	2,410
43			893.0 Maintenance Of Meters And House Regulators.							4	173
44			894.0 Maintenance Of Other Equipment.							2	618
45			Subtotal							$343	$21,902
46											
47			Distribution Expense Subtotal				($2,188)			($1,096)	$75,653
48											

($ in Thousands)

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.							$0	$41
50			903.0 Customer Records And Collection Expenses.							234	20,209
51			904.0 Uncollectible Accounts.				(1,961)			360	2,988
52			905.0 Miscellaneous Customer Accounts Expenses.	684		($10)				685	1,491
53											
54			Subtotal	$684		($10)	($1,961)			$1,279	$24,729
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses							$6	$7,800
57			909.0 Informational And Instructional Advertising Expenses.								667
58			910.0 Miscellaneous Customer Service And Informational Expenses.								
59			Subtotal							$6	$8,467
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.							$12	$842
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal							$12	$842
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.							$297	$7,991
66			921.0 Office Supplies And Expenses.								710
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.								22,293
69			924.0 Property Insurance.								209
70			925.0 Injuries And Damages.							5	4,348
71			926.0 Employee Pensions And Benefits.							(860)	9,177
72			928.0 Regulatory Commission Expenses.								2,636
73			929.0 Duplicate Charges--Credit.								(8)
74			930.2 Miscellaneous General Expenses.							0	853
75											
76			Subtotal							($558)	$48,207
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.							$6	$957
79			Subtotal							$6	$957
80											
81			A&G Expense Sub-total							($552)	$49,164
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$4,825	$4,825	$113,899
84			403.1 Depreciation Expense - ARO/FIN-47								-
85			404.0 Amort. Of Limited-Term Plant						2,232	2,232	17,816
86			Subtotal						$7,057	$7,057	$131,715
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.		$32					$470	$2,866
89			Subtotal		$32					$470	$2,866
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					$169		$169	$10,270
92			Subtotal					$169		$169	$10,270
93											
94			**Total**	**$684**	**$32**	**($10)**	**($4,149)**	**$169**	**$7,057**	**($7,533)**	**$602,946**

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) FPFTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5D Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-5F Weather Normal Adjustment	(8) Adjustments Sub-total	(9) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	480.0	$396,580	$543	($200)	$437			($15,034)	($14,254)	$382,326
2			C & I	481.0	147,498	519		171			(4,152)	(3,462)	144,036
3			Transportation of Gas of Others	489.3	34,445						(278)	(278)	34,167
4				Subtotal	$578,523	$1,062	($200)	$607			($19,464)	($17,994)	$560,529
5													
6		**Gas Cost Revenue**	Residential	480.0	$222,710								$222,710
7			C & I	481.0	68,654								68,654
8			Interdepartmental	484.0									
9				Subtotal	$291,363								$291,363
10													
11			**Subtotal OPERATING REVENUE**		$869,886	$1,062	($200)	$607			($19,464)	($17,994)	$851,892
12													
13	*OTHER REVENUE*	**Other Gas Revenue**	Rent for Gas Property	493.0	$2,991								$2,991
14			Interdepartmental Rents	494.0									
15			Other Gas Revenues	495.0	835								835
16				Subtotal	$3,825								$3,825
17													
18		**Other Operating Revenue**	Sales For Resale	483.0	$20,000					($20,000)		($20,000)	
19			Forfeited Discounts	487.0	1,314								1,314
20													
21			Miscellaneous Service Revenues	488.0									
22				Subtotal	$21,314					($20,000)		($20,000)	$1,314
23													
24			**Subtotal OTHER REVENUE**		$25,140					($20,000)		($20,000)	$5,140
25													
26				**Total**	**$895,026**	**$1,062**	**($200)**	**$607**		**($20,000)**	**($19,464)**	**($37,994)**	**$857,032**

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Reference	480000: Residential Sales	481001: TCS Sales	481002: GC Sales	481003: L Sales	481005: Other Sales	C & I Total
1	Total FPFTY Revenues		$619,290	$1,374	$213,351	$256	$997	$215,979
2	Commodity Billings in Revenues		(222,710)	(550)	(67,551)	(93)	(375)	(68,569)
3	Weather Adjustment							
4	Total Reconcilable Surcharge in Revenues		15,143	-	-	-	-	-
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$411,723	$825	$145,800	$163	$622	$147,410
6								
7	Average Monthly Customers in FPFTY		514,451	21	44,863	6	16	
8								
9	Average Annual Margin Per Customer	L5 / L7	$0.800	$39.270	$3.250	$27.169	$38.858	
10								
11	Number of Customers of Current Month		515,130	21	45,023	6	16	45,066
12								
13	Increase in Customers During FPFTY	L11 - L7	679		160			45,066
14								
15	Annualization of Revenue	L9 * L13	$543		$519			$519

($ in Thousands)

D-5B - CAP Revenue Credits and Adjustments

		(1)	(2)
Line No.	Description	Reference	Residential Sales
1	CAP Discount		($16,447)
2			
3			
4	**ANNUALIZATION TO YEAR END CUSTOMERS**		
5			
6	Annual CAP Customers		323,992
7	Average Monthly CAP Customers		26,999
8	Average Annual CAP Discount Per Customer	L1 / L7	($0.609)
9			
10	CAP Customers at End of FPFTY		27,372
11	Decrease of CAP Customers	L10 - L7	372
12			
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	($227)
14	Write-Offs & Working Capital Factor		11.9%
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	$27
16			
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**($200)**

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Reference	480000: Residential Sales	481001: TCS Sales	481002: GC Sales	481003: L Sales	481005: Other Sales	C & I Total
1	Revenue in February of FPFTY		$48,930	$111	$18,931	$12	$48	$19,101
2	Days in February of FPFTY		28	28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	1,748	4	676	0	2	
4	Average Days in February		28.25	28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	0.25	
6								
7	**Leap Year Adjustment**	L3 * L5	**$437**	**$1**	**$169**	**$0**	**$0**	**$171**

Line No.	Description	Total
		(1)
1	Residential Sales	
2	TCS Sales	
3	GC Sales	
4	C & I Total	
5	Revenues - Gas Transportation	
6	**Total**	

			(1)
Line No.	Description	Account	Total
1	Other Operating Revenue	483000: Sales for Resale - Gas	($20,000)
2			
3	Purchased Fuel	804000: Natural Gas City Gate Purchases	($15,000)

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2027
($ in Thousands)

D-5F - 30-Year vs. 10-Year Weather Normal Adjustment

Line No.	Description	(1) Total
1	Residential Sales	($15,034)
2	TCS Sales	(25)
3	GC Sales	(4,109)
4	Large C&I	(4)
5	Other	(14)
6	Transportation	(278)
7	**Total**	**($19,464)**

($ in Thousands)

		(1)	(2)	(3)
Line No.	Description	Reference	Union	Non-Union
1	Number of Employees @ HTY - Union/Non-Union		354	341
2	Number of Employees @ HTY - Total		695	695
3	Percentage of Employees @ HTY	L1 / L2	50.92%	49.08%
4	Distribution of Budget S&W Expense		$25,468	$24,549
5				
6	**Annualize March 1 Wage Increase for FPFTY**			
7	Number of Months TY			2
8	Rate for Increase TY		3.00%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$123
10		L4 + L9	$25,468	$24,672
11				
12	**Annualize January 1 and March 1, 2028 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		3.00%	3.00%
15	Total Adjustment	(L10 * L13 * L14) / 12	$764	$740
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$26,232**	**$25,412**

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	PECO - Gas
1	Distribution of S&W Expense		$50,017
2			
3	Annualized S&W Including Wage Increases		$51,644
4			
5	**Normalize Contract Payment to Union**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		18.56%
8	Union Contract Payment for Utility	L6 * L7	$242
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$40
11			
12	Annualized S&W for Employees in FPFTY	L3 + L10	$51,685
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ FPFTY		677
16	Average Number of Employees in FPFTY - Total		676
17	Annualization for Number of Employees	L15 - L16	2
18	Annual S&W per Employee	L12 / L16	$76.5
19	Annualization of S&W for New Employees	L17 * L18	$119
20			
21	Pro Forma FPFTY S&W	L12 + L19	$51,803
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$1,786**
24			
25	S&W Pro Forma Factor	L23 / L1	3.57%

($ in Thousands)

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
1	**Operations**	Power Supply Expenses	710.0 Operation Supervision And Engineering.			
2			717.0 Liquefied Petroleum Gas Expenses.	$64	2	$66
3			728.0 Liquefied Petroleum Gas.			
4			804.0 Natural Gas City Gate Purchases.			
5			805.0 Other Gas Purchases.			
6			805.1 Purchased Gas Cost Adjustments.			
7			807.0 Purchased Gas Expenses.			
8			808.1 Gas Withdrawn From Storage-Debit.			
9			808.2 Gas Delivered To Storage-Credit.			
10			813.0 Other Gas Supply Expenses.			
11			840.0 Operation Supervision And Engineering.	234	8	242
12			841.0 Operation Labor And Expenses.	548	20	568
13			843.1 Maintenance Supervision And Engineering.	562	20	582
14			843.2 Maintenance Of Structures And Improvements.	1,874	67	1,941
15			**Subtotal Power Supply Expenses**	$3,282	$117	$3,399
16						
17		Distribution Expense	870.0 Operation Supervision And Engineering.	$9	$0	$10
18			874.0 Mains And Services Expenses.	8,556	305	8,862
19			875.0 Measuring And Regulating Station Expenses--General.	881	31	913
20			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.			
21			878.0 Meter And House Regulator Expenses.	2,115	76	2,190
22			879.0 Customer Installations Expenses.	4,942	176	5,118
23			880.0 Other Expenses.	4,485	160	4,645
24			881.0 Rents.			
25			885.0 Maintenance Supervision And Engineering.			
26			887.0 Maintenance Of Mains.	7,842	280	8,122
27			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	404	14	418
28			892.0 Maintenance Of Services.	1,166	42	1,208
29			893.0 Maintenance Of Meters And House Regulators.	115	4	119
30			894.0 Maintenance Of Other Equipment.	66	2	69
31			**Subtotal Distribution Expense**	$30,581	$1,092	$31,673
32						
33		Customer Accounts	902.0 Meter Reading Expenses.	$0	$0	$0
34			903.0 Customer Records And Collection Expenses.	6,566	234	6,801
35			904.0 Uncollectible Accounts.			
36			905.0 Miscellaneous Customer Accounts Expenses.	302	11	313
37						
38			**Subtotal Customer Accounts**	$6,868	$245	$7,114
39						
40		Customer Service & Information	908.0 Customer Assistance Expenses	$169	$6	$175

($ in Thousands)

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
41			909.0 Informational And Instructional Advertising Expenses.			
42			910.0 Miscellaneous Customer Service And Informational Expenses.			
43			**Subtotal Customer Service & Information**	$169	$6	$175
44						
45		Sales	912.0 Demonstrating And Selling Expenses.	$330	$12	$342
46			916.0 Miscellaneous Sales Expenses.			
47			**Subtotal Sales**	$330	$12	$342
48						
49		Administration & General - General	920.0 Administrative And General Salaries.	$8,318	$297	$8,615
50			921.0 Office Supplies And Expenses.			
51			922.0 Administrative Expenses Transferred--Credit.			
52			923.0 Outside Services Employed.			
53			924.0 Property Insurance.			
54			925.0 Injuries And Damages.	144	5	150
55			926.0 Employee Pensions And Benefits.			
56			928.0 Regulatory Commission Expenses.			
57			929.0 Duplicate Charges--Credit.			
58			930.2 Miscellaneous General Expenses.	0	0	0
59						
60			**Subtotal Administration & General - General**	$8,462	$302	$8,764
61						
62			**Subtotal Operations**	$49,694	$1,774	$51,468
63						
64	**Maintenance**	Administration & General - General	932.0 Maintenance Of Gas General Plant.	$174	$6	$180
65			**Subtotal Administration & General - General**	$174	$6	$180
66						
67		Gas Expense	741.0 Maintenance Of Structures And Improvements.	$43	$2	$44
68			742.0 Maintenance Of Production Equipment.	107	4	111
69			**Subtotal Gas Expense**	$150	$5	$155
70						
71			**Subtotal Maintenance**	$324	$12	$335
72						
73	**Total Operations & Maintenance**		**Total Operations & Maintenance**	$50,017	$1,786	$51,803
74						
75	**Percent Increase**		**Percent Increase**			3.57%

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$47
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		31
4	**Total Recorded Up To Period End of HTY**	SUM L2 to L3	$78
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$2,782
8	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		365
9	**Total Expenditure Expected in FTY**	SUM L7 to L8	$3,148
10			
11	**Total Rate Case Expense**	L4 + L9	$3,226
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,613
15			
16	Annual Amortization Amount Included in Budget		$1,613
17	Pro Forma Adjustment for Annual Amortization	L14 - L16	**$0**

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	**Number of Employees**		
2	Employees at Eleven Months Prior		674
3	Employees at Ten Months Prior		674
4	Employees at Nine Months Prior		674
5	Employees at Eight Months Prior		674
6	Employees at Seven Months Prior		675
7	Employees at Six Months Prior		676
8	Employees at Five Months Prior		676
9	Employees at Four Months Prior		677
10	Employees at Three Months Prior		677
11	Employees at Two Months Prior		677
12	Employees at One Month Prior		677
13	Employees at End of FPFTY		677
14			
15	Average Monthly Employees in FPFTY	AVERAGE L2 to L13	676
16	Additional Employees in FPFTY		2
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$7,739
20	Number of Employees for Budget		676
21	Budget Expense Per Employee	L19 / L20	$11
22	Additional Employees for Annualization	L16	2
23	Total Benefits Pro Forma Adjustment	L21 * L22	$18

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	Pension Contribution for Four Years Prior to FPFTY		$1,408
2	Pension Contribution for Three Years Prior to FPFTY		3,690
3	Pension Contribution for Two Years Prior to FPFTY		11,760
4	Pension Contribution for One Year Prior to FPFTY		10,374
5	Pension Contribution for FPFTY		10,508
6			
7	Average Pension Contribution	AVERAGE L1 to L5	$7,548
8			
9	Allocation Percent to Utility		18.56%
10	Total Amount to Utility	L7 * L9	$1,401
11	Allocation Percent to Capital		42.01%
12	Pension Contribution To Be Capitalized	L10 * L11	$589
13	Pension Contribution To Be Expensed	L10 - L12	$812
14	Budgeted Test Year Distribution Pension Expense		$1,690
15	Additional Pension Expense	L13 - L14	**($878)**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	Reference	Charge Off Amounts	Billed Revenue	Percent	Totals
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$3,091	$778,733	0.3970%	
2		One Year Prior to HTY		2,884	687,070	0.4197%	
3		HTY		6,465	912,486	0.7085%	
4		Three Year Average	SUM L1 to L3 / 3	$4,147	$792,763	0.5231%	
5							
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	FPFTY			$851,892		
7							
8	Tariff Revenue - Non Shopping Revenue	FPFTY	L6		$851,892		
9							
10	Tariff Revenue - Shopping Revenue	FPFTY			$94,341		
11							
12	Tariff Revenue - Including Shopping Revenue	FPFTY	L8 + L10		$946,233		
13							
14	**Total General Pro Forma Uncollectible Accounts**		Col 4 L4 * L12				$4,949
15							
16	Uncollectible Accounts (904)	FPFTY					$2,629
17							
18	**Total Pro Forma Adjustment for Uncollectible Accounts**		L14 - L16				**$2,321**

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Residential Natural Gas Energy Efficiency Program		$423
2	Commercial Natural Gas Energy Efficiency Program		42
3	Sub-total Pro Forma Increase in Gas Energy Efficiency Program Costs	L1 + L2	$464
4	Gas Commercial EE Program Refund - Rate GC		($52)
5	Amortization Years		2
6	Annual Amortization Amount of Gas Commercial EE Program Refund	L4 / L5	($26)
7	Total Gas Energy Efficiency Program Pro Forma Adjustment Amount	L3 + L6	**$438**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Description	Reference	Interest Rate	Deposit Amount	Interest on Deposit Amount	Interest Sub Total	Interest Total
1	**Residential**	Monthly Interest Rate		0.583%				
2								
3	January				4,235	25		
4	February				4,342	25		
5	March				4,548	27		
6	April				4,832	28		
7	May				5,032	29		
8	June				5,094	30		
9	July				5,198	30		
10	August				5,305	31		
11	September				5,457	32		
12	October				5,614	33		
13	November				5,723	33		
14	December				5,791	34		
15	**Total Residential**		SUM Col 4 L3 to L14				$357	
16								
17	**Non-Residential**	Monthly Interest Rate		0.292%				
18								
19	January				8,434	25		
20	February				8,568	25		
21	March				8,856	26		
22	April				9,143	27		
23	May				9,347	27		
24	June				9,381	27		
25	July				9,471	28		
26	August				9,539	28		
27	September				9,677	28		
28	October				9,861	29		
29	November				9,900	29		
30	December				10,091	29		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$327	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					$684

		(1)	(2)
Line No.	Description	Reference	Total
1	Regulatory Asset for Unrecovered MGP Remediation Liability		$11,705
2	Amortization Years		8
3			
4	**Total Annual Amortization Amount**	L1/L2	$1,463
5			
6	Amount Included in Budget		$1,431
7			
8	**Pro Forma Adjustment Amount**	L4 - L6	**$32**

		(1)	(2)
Line No.	Description	Reference	Total
1	Customer Interest on Unspent MGP Collections		($1,316)
2	Amortization Years		2
3	Pro Forma Adjustment Amount	L1 / L2	($658)
4	Annual Amortization Amount Included in Budget		($648)
5	**Pro Forma Adjustment for Annual Amortization**	L3 - L4	**($10)**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2027
($ in Thousands)
D-15 - Gas Procurement and Merchant Function Charges

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Gas Procurement Charge		
2	Rate GR		($1,408)
3	Rate GC		($766)
4	Rate L		($1)
5	Rate OL		
6	Rate MV-F		($13)
7	Total Gas Procurement Charge	SUM L2 to L6	($2,188)
8			
9	Merchant Function Charge / POR		
10	Rate GR		($1,665)
11	Rate GC		($296)
12	Rate L		
13	Rate OL		
14	Rate MV-F		
15	Total Merchant Function Charge / POR	SUM L10 to L14	($1,961)
16			
17	**Total Gas Procurement and Merchant Function Charges**	L7 + L15	**($4,149)**

($ in Thousands)

Line No.	Description	(1) Total	(2) Pro Forma Adjustments	(3) Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,383		$2,383
2	Capital Stock & Franchise Tax			
3	Use Tax Accrued	817		817
4	Real Estate Tax Accrual	2,182		2,182
5	Miscellaneous TOTI			
6	Payroll Tax Accrued	4,720	$169	4,889
7	**Total**	$10,102	$169	**$10,270**

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Total Payroll Charged to Expense		$50,017
2	Payroll Tax Expense		$4,720
3	Payroll Tax Expense - Percent	L2 / L1	9.44%
4	Pro Forma Increase in S&W		$1,786
5	**Payroll Tax Pro Forma**	L3 * L4	**$169**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2027
($ in Thousands)
D-17 Depreciation Adjustment

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	$4,946	$102	$4,844	$102	$5,049
2			PECO Common 3902 IL	16		16		16
3			PECO Common 3902 PA	6,497	667	5,830	667	7,164
4			PECO Common 3903 PA	296	39	256	39	335
5			PECO Common 3911 PA	13		13		13
6			PECO Common 3912 PA	2,298	31	2,267	31	2,329
7			PECO Common 3913 IL	4,227	364	3,863	364	4,591
8			PECO Common 3913 PA	16,417	2,617	13,800	2,617	19,034
9			PECO Common 3930 PA	146	6	140	6	152
10			PECO Common 3941 PA	0		0		0
11			PECO Common 3942 PA	69	0	68	0	69
12			PECO Common 3970 PA	6,647	166	6,481	166	6,813
13			PECO Common 3980 PA					
14			Subtotal Common - General Plant	$41,571	$3,993	$37,577	$3,993	$45,564
15								
16		Gas - Distribution	PECO Gas 3751 PA	$331	$25	$307	$25	$356
17			PECO Gas 3752 PA	204	19	185	19	223
18			PECO Gas 3753 PA	122	2	120	2	123
19			PECO Gas 3761 PA	15,420	737	14,684	737	16,157
20			PECO Gas 3762 PA	1,401		1,401		1,401
21			PECO Gas 3763 PA	31,583	1,629	29,954	1,629	33,212
22			PECO Gas 3780 PA	710	33	676	33	743
23			PECO Gas 3790 PA	1,540	76	1,463	76	1,616
24			PECO Gas 3801 PA	3,920	5	3,915	5	3,924
25			PECO Gas 3802 PA	24,920	845	24,075	845	25,765
26			PECO Gas 3810 PA	2,319	44	2,275	44	2,363
27			PECO Gas 3811 PA	3,532	16	3,516	16	3,548
28			PECO Gas 3820 PA	5,695	196	5,499	196	5,892
29			PECO Gas 3870 PA	108		108		108
30			Subtotal Gas - Distribution	$91,805	$3,627	$88,178	$3,627	$95,431
31								

($ in Thousands)

				(1)	(2)	(3)	(4)	(5)
Line No.	Account	Plant Account	Depreciation Category	Depr on Existing Assets + Adds	Depr on Adds	Depr on Existing Assets	Annualize Current Yr Depr	Pro Forma Test Yr Depr
32		Gas - General Plant	PECO Gas 3901 PA	$106	$1	$105	$1	$107
33			PECO Gas 3902 PA	54	0	54	0	54
34			PECO Gas 3903 PA	79	3	76	3	83
35			PECO Gas 3911 PA					
36			PECO Gas 3912 PA	44		44		44
37			PECO Gas 3913 IL					
38			PECO Gas 3913 PA	566	10	556	10	576
39			PECO Gas 3940 PA	1,096	27	1,070	27	1,123
40			PECO Gas 3950 PA	2		2		2
41			PECO Gas 3970 PA	352	5	347	5	358
42			PECO Gas 3980 PA	8		8		8
43			Subtotal Gas - General Plant	$2,307	$47	$2,260	$47	$2,354
44								
45		Gas - Production Plant	PECO Gas 3050 PA	$34		$34		$34
46			PECO Gas 3053 PA					
47			PECO Gas 3110 PA	169		169		169
48			Subtotal Gas - Production Plant	$203		$203		$203
49								
50		Gas - Storage	PECO Gas 3611 PA	$40		$40		$40
51			PECO Gas 3612 PA	263	1	262	1	263
52			PECO Gas 3613 PA	18		18		18
53			PECO Gas 3620 PA	8		8		8
54			PECO Gas 3630 PA	19		19		19
55			PECO Gas 3631 PA	129	1	128	1	129
56			PECO Gas 3632 PA	3,085	188	2,897	188	3,273
57			PECO Gas 3633 PA	679	1	678	1	680
58			PECO Gas 3634 PA	540	27	513	27	566
59			PECO Gas 3635 PA	410	16	395	16	426
60			Subtotal Gas - Storage	$5,190	$232	$4,957	$232	$5,422
61								
62			Subtotal 403.0 Depreciation Expense.	$141,075	$7,899	$133,176	$7,899	$148,974
63								

($ in Thousands)

				(1)	(2)	(3)	(4)	(5)
Line No.	Account	Plant Account	Depreciation Category	Depr on Existing Assets + Adds	Depr on Adds	Depr on Existing Assets	Annualize Current Yr Depr	Pro Forma Test Yr Depr
64	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 303-CFP B&P SW	$152		$152		$152
65			PECO Com 303-CFP MEU SW	135		135		135
66			PECO Com 303-CFP MMA SW	137		137		137
67			PECO Com 303-DSS Platform Enhanc SW	147		147		147
68			PECO Com 303-EU Custom Hardening SW	277		277		277
69			PECO Com 303-EU EAM SW	1,544	$1,276	268	1,276	2,820
70			PECO Com 303-EU GIS Core SW	6,981		6,981		6,981
71			PECO Com 303-EU Reliab-Auto SW	139		139		139
72			PECO Com 303-Grid FR Workstream SW	99		99		99
73			PECO Com 303-IGA Enhance Prog SW-C	278		278		278
74			PECO Com 303-LMR SW C	367		367		367
75			PECO Com 303-MO New Bus. Portal SW	170		170		170
76			PECO Com 3030-Apollo SW	5,365	$4,440	925	4,440	9,805
77			PECO Com 3030-BIDA-AMI Ph2 SW	2		2		2
78			PECO Com 3030-Cloud Serv 3 yr	766		766		766
79			PECO Com 3030-Cloud Serv 5 yr	4,851	$153	4,698	153	5,003
80			PECO Com 3030-Common MDM SW	228		228		228
81			PECO Com 3030-EU Digital Program We	1,679		1,679		1,679
82			PECO Com 3030-EU oneMDS SW	4,314		4,314		4,314
83			PECO Com 3030-I Sign Up and Move	385		385		385
84			PECO Com 3030-IT Cust Mobile App SW	50		50		50
85			PECO Com 3030-IVR System PA	177		177		177
86			PECO Com 3030-Misc 5 yr FR PA	19,631	$3,826	15,805	3,826	23,457
87			Subtotal Common - Intangible Plant	$47,875	$9,695	$38,180	$9,695	$57,570
88								
89			PECO Gas 3913 PA					
90			Subtotal					
91								
92		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	$1,138		$1,138		$1,138
93			PECO Gas 303-CC&B SW	3,353		3,353		3,353
94			PECO Gas 303-PECO RNI Upgrade SW G	41		41		41
95			PECO Gas 303-SES IV G SW	32		32		32
96			Subtotal Gas - Intangible Plant	$4,563		$4,563		$4,563
97								
98			Subtotal 404.0 Amort. Of Limited-Term Plant	$52,438	$9,695	$42,743	$9,695	$62,133
99								
100			Grand Total	**$193,513**	**$17,594**	**$175,919**	**$17,594**	**$211,107**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2027
($ in Thousands)
D-17 Depreciation Adjustment

				(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account	Plant Account	Depreciation Category	Utility Allocation Factor	Depr on Existing Assets + Adds (Utility)	Depr on Adds (Utility)	Depr on Existing Assets (Utility)	Annualize Current Yr Depr (Utility)	Pro Forma Test Yr Depr (Utility)
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	0.2302	$1,139	$24	$1,115	$24	$1,162
2			PECO Common 3902 IL	0.2302	4		4		4
3			PECO Common 3902 PA	0.2302	1,496	154	1,342	154	1,649
4			PECO Common 3903 PA	0.2302	68	9	59	9	77
5			PECO Common 3911 PA	0.2302	3		3		3
6			PECO Common 3912 PA	0.2302	529	7	522	7	536
7			PECO Common 3913 IL	0.2302	973	84	889	84	1,057
8			PECO Common 3913 PA	0.2302	3,779	602	3,177	602	4,382
9			PECO Common 3930 PA	0.2302	34	1	32	1	35
10			PECO Common 3941 PA	0.2302	0		0		0
11			PECO Common 3942 PA	0.2302	16	0	16	0	16
12			PECO Common 3970 PA	0.2302	1,530	38	1,492	38	1,568
13			PECO Common 3980 PA	0.2302					
14			Subtotal Common - General Plant		$9,570	$919	$8,650	$919	$10,489
15									
16		Gas - Distribution	PECO Gas 3751 PA	1.0000	$331	$25	$307	$25	$356
17			PECO Gas 3752 PA	1.0000	204	19	185	19	223
18			PECO Gas 3753 PA	1.0000	122	2	120	2	123
19			PECO Gas 3761 PA	1.0000	15,420	737	14,684	737	16,157
20			PECO Gas 3762 PA	1.0000	1,401		1,401		1,401
21			PECO Gas 3763 PA	1.0000	31,583	1,629	29,954	1,629	33,212
22			PECO Gas 3780 PA	1.0000	710	33	676	33	743
23			PECO Gas 3790 PA	1.0000	1,540	76	1,463	76	1,616
24			PECO Gas 3801 PA	1.0000	3,920	5	3,915	5	3,924
25			PECO Gas 3802 PA	1.0000	24,920	845	24,075	845	25,765
26			PECO Gas 3810 PA	1.0000	2,319	44	2,275	44	2,363
27			PECO Gas 3811 PA	1.0000	3,532	16	3,516	16	3,548
28			PECO Gas 3820 PA	1.0000	5,695	196	5,499	196	5,892
29			PECO Gas 3870 PA	1.0000	108		108		108
30			Subtotal Gas - Distribution		$91,805	$3,627	$88,178	$3,627	$95,431
31									

($ in Thousands)

				(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account	Plant Account	Depreciation Category	Utility Allocation Factor	Depr on Existing Assets + Adds (Utility)	Depr on Adds (Utility)	Depr on Existing Assets (Utility)	Annualize Current Yr Depr (Utility)	Pro Forma Test Yr Depr (Utility)
32		Gas - General Plant	PECO Gas 3901 PA	1.0000	$106	$1	$105	$1	$107
33			PECO Gas 3902 PA	1.0000	54	0	54	0	54
34			PECO Gas 3903 PA	1.0000	79	3	76	3	83
35			PECO Gas 3911 PA	1.0000					
36			PECO Gas 3912 PA	1.0000	44		44		44
37			PECO Gas 3913 IL	1.0000					
38			PECO Gas 3913 PA	1.0000	566	10	556	10	576
39			PECO Gas 3940 PA	1.0000	1,096	27	1,070	27	1,123
40			PECO Gas 3950 PA	1.0000	2		2		2
41			PECO Gas 3970 PA	1.0000	352	5	347	5	358
42			PECO Gas 3980 PA	1.0000	8		8		8
43			Subtotal Gas - General Plant		$2,307	$47	$2,260	$47	$2,354
44									
45		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$34		$34		$34
46			PECO Gas 3053 PA	1.0000					
47			PECO Gas 3110 PA	1.0000	169		169		169
48			Subtotal Gas - Production Plant		$203		$203		$203
49									
50		Gas - Storage	PECO Gas 3611 PA	1.0000	$40		$40		$40
51			PECO Gas 3612 PA	1.0000	263	1	262	1	263
52			PECO Gas 3613 PA	1.0000	18		18		18
53			PECO Gas 3620 PA	1.0000	8		8		8
54			PECO Gas 3630 PA	1.0000	19		19		19
55			PECO Gas 3631 PA	1.0000	129	1	128	1	129
56			PECO Gas 3632 PA	1.0000	3,085	188	2,897	188	3,273
57			PECO Gas 3633 PA	1.0000	679	1	678	1	680
58			PECO Gas 3634 PA	1.0000	540	27	513	27	566
59			PECO Gas 3635 PA	1.0000	410	16	395	16	426
60			Subtotal Gas - Storage		$5,190	$232	$4,957	$232	$5,422
61									
62			Subtotal 403.0 Depreciation Expense.		$109,074	$4,825	$104,249	$4,825	$113,899
63									

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FPFTY Ending December 2027
($ in Thousands)
D-17 Depreciation Adjustment

				(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account	Plant Account	Depreciation Category	Utility Allocation Factor	Depr on Existing Assets + Adds (Utility)	Depr on Adds (Utility)	Depr on Existing Assets (Utility)	Annualize Current Yr Depr (Utility)	Pro Forma Test Yr Depr (Utility)
64	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 303-CFP B&P SW	0.2302	$35		$35		$35
65			PECO Com 303-CFP MEU SW	0.2302	31		31		31
66			PECO Com 303-CFP MMA SW	0.2302	32		32		32
67			PECO Com 303-DSS Platform Enhanc SW	0.2302	34		34		34
68			PECO Com 303-EU Custom Hardening SW	0.2302	64		64		64
69			PECO Com 303-EU EAM SW	0.2302	355	294	62	294	649
70			PECO Com 303-EU GIS Core SW	0.2302	1,607		1,607		1,607
71			PECO Com 303-EU Reliab-Auto SW	0.2302	32		32		32
72			PECO Com 303-Grid FR Workstream SW	0.2302	23		23		23
73			PECO Com 303-IGA Enhance Prog SW-C	0.2302	64		64		64
74			PECO Com 303-LMR SW C	0.2302	85		85		85
75			PECO Com 303-MO New Bus. Portal SW	0.2302	39		39		39
76			PECO Com 3030-Apollo SW	0.2302	1,235	1,022	213	1,022	2,257
77			PECO Com 3030-BIDA-AMI Ph2 SW	0.2302	0		0		0
78			PECO Com 3030-Cloud Serv 3 yr	0.2302	176		176		176
79			PECO Com 3030-Cloud Serv 5 yr	0.2302	1,117	35	1,081	35	1,152
80			PECO Com 3030-Common MDM SW	0.2302	53		53		53
81			PECO Com 3030-EU Digital Program We	0.2302	387		387		387
82			PECO Com 3030-EU oneMDS SW	0.2302	993		993		993
83			PECO Com 3030-I Sign Up and Move	0.2302	89		89		89
84			PECO Com 3030-IT Cust Mobile App SW	0.2302	12		12		12
85			PECO Com 3030-IVR System PA	0.2302	41		41		41
86			PECO Com 3030-Misc 5 yr FR PA	0.2302	4,519	881	3,638	881	5,400
87			Subtotal Common - Intangible Plant		$11,021	$2,232	$8,789	$2,232	$13,253
88									
89			PECO Gas 3913 PA	1.0000					
90			Subtotal						
91									
92		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$1,138		$1,138		$1,138
93			PECO Gas 303-CC&B SW	1.0000	3,353		3,353		3,353
94			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	41		41		41
95			PECO Gas 303-SES IV G SW	1.0000	32		32		32
96			Subtotal Gas - Intangible Plant		$4,563		$4,563		$4,563
97					1.0000				
98			Subtotal 404.0 Amort. Of Limited-Term Plant		$15,584	$2,232	$13,352	$2,232	$17,816
99									
100			Grand Total		**$124,658**	**$7,057**	**$117,602**	**$7,057**	**$131,715**

($ in Thousands)

				(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Account	Plant Account	Depreciation Category	Functional Allocation Factor	Depr on Existing Assets + Adds (Function)	Depr on Adds (Function)	Depr on Existing Assets (Function)	Annualize Current Yr Depr (Function)	Pro Forma FPFTY Depr (Function)
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	1.0000	$1,139	$24	$1,115	$24	$1,162
2			PECO Common 3902 IL	1.0000	4		4		4
3			PECO Common 3902 PA	1.0000	1,496	154	1,342	154	1,649
4			PECO Common 3903 PA	1.0000	68	9	59	9	77
5			PECO Common 3911 PA	1.0000	3		3		3
6			PECO Common 3912 PA	1.0000	529	7	522	7	536
7			PECO Common 3913 IL	1.0000	973	84	889	84	1,057
8			PECO Common 3913 PA	1.0000	3,779	602	3,177	602	4,382
9			PECO Common 3930 PA	1.0000	34	1	32	1	35
10			PECO Common 3941 PA	1.0000	0		0		0
11			PECO Common 3942 PA	1.0000	16	0	16	0	16
12			PECO Common 3970 PA	1.0000	1,530	38	1,492	38	1,568
13			PECO Common 3980 PA	1.0000					
14			Subtotal Common - General Plant		$9,570	$919	$8,650	$919	$10,489
15									
16		Gas - Distribution	PECO Gas 3751 PA	1.0000	$331	$25	$307	$25	$356
17			PECO Gas 3752 PA	1.0000	204	19	185	19	223
18			PECO Gas 3753 PA	1.0000	122	2	120	2	123
19			PECO Gas 3761 PA	1.0000	15,420	737	14,684	737	16,157
20			PECO Gas 3762 PA	1.0000	1,401		1,401		1,401
21			PECO Gas 3763 PA	1.0000	31,583	1,629	29,954	1,629	33,212
22			PECO Gas 3780 PA	1.0000	710	33	676	33	743
23			PECO Gas 3790 PA	1.0000	1,540	76	1,463	76	1,616
24			PECO Gas 3801 PA	1.0000	3,920	5	3,915	5	3,924
25			PECO Gas 3802 PA	1.0000	24,920	845	24,075	845	25,765
26			PECO Gas 3810 PA	1.0000	2,319	44	2,275	44	2,363
27			PECO Gas 3811 PA	1.0000	3,532	16	3,516	16	3,548
28			PECO Gas 3820 PA	1.0000	5,695	196	5,499	196	5,892
29			PECO Gas 3870 PA	1.0000	108		108		108
30			Subtotal Gas - Distribution		$91,805	$3,627	$88,178	$3,627	$95,431
31									

($ in Thousands)

				(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Account	Plant Account	Depreciation Category	Functional Allocation Factor	Depr on Existing Assets + Adds (Function)	Depr on Adds (Function)	Depr on Existing Assets (Function)	Annualize Current Yr Depr (Function)	Pro Forma FPFTY Depr (Function)
32		Gas - General Plant	PECO Gas 3901 PA	1.0000	$106	$1	$105	$1	$107
33			PECO Gas 3902 PA	1.0000	54	0	54	0	54
34			PECO Gas 3903 PA	1.0000	79	3	76	3	83
35			PECO Gas 3911 PA	1.0000					
36			PECO Gas 3912 PA	1.0000	44		44		44
37			PECO Gas 3913 IL	1.0000					
38			PECO Gas 3913 PA	1.0000	566	10	556	10	576
39			PECO Gas 3940 PA	1.0000	1,096	27	1,070	27	1,123
40			PECO Gas 3950 PA	1.0000	2		2		2
41			PECO Gas 3970 PA	1.0000	352	5	347	5	358
42			PECO Gas 3980 PA	1.0000	8		8		8
43			Subtotal Gas - General Plant		$2,307	$47	$2,260	$47	$2,354
44									
45		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$34		$34		$34
46			PECO Gas 3053 PA	1.0000					
47			PECO Gas 3110 PA	1.0000	169		169		169
48			Subtotal Gas - Production Plant		$203		$203		$203
49									
50		Gas - Storage	PECO Gas 3611 PA	1.0000	$40		$40		$40
51			PECO Gas 3612 PA	1.0000	263	1	262	1	263
52			PECO Gas 3613 PA	1.0000	18		18		18
53			PECO Gas 3620 PA	1.0000	8		8		8
54			PECO Gas 3630 PA	1.0000	19		19		19
55			PECO Gas 3631 PA	1.0000	129	1	128	1	129
56			PECO Gas 3632 PA	1.0000	3,085	188	2,897	188	3,273
57			PECO Gas 3633 PA	1.0000	679	1	678	1	680
58			PECO Gas 3634 PA	1.0000	540	27	513	27	566
59			PECO Gas 3635 PA	1.0000	410	16	395	16	426
60			Subtotal Gas - Storage		$5,190	$232	$4,957	$232	$5,422
61									
62			Subtotal 403.0 Depreciation Expense.		$109,074	$4,825	$104,249	$4,825	$113,899
63									

($ in Thousands)

				(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Account	Plant Account	Depreciation Category	Functional Allocation Factor	Depr on Existing Assets + Adds (Function)	Depr on Adds (Function)	Depr on Existing Assets (Function)	Annualize Current Yr Depr (Function)	Pro Forma FPFTY Depr (Function)
64	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 303-CFP B&P SW	1.0000	$35		$35		$35
65			PECO Com 303-CFP MEU SW	1.0000	31		31		31
66			PECO Com 303-CFP MMA SW	1.0000	32		32		32
67			PECO Com 303-DSS Platform Enhanc SW	1.0000	34		34		34
68			PECO Com 303-EU Custom Hardening SW	1.0000	64		64		64
69			PECO Com 303-EU EAM SW	1.0000	355	294	62	294	649
70			PECO Com 303-EU GIS Core SW	1.0000	1,607		1,607		1,607
71			PECO Com 303-EU Reliab-Auto SW	1.0000	32		32		32
72			PECO Com 303-Grid FR Workstream SW	1.0000	23		23		23
73			PECO Com 303-IGA Enhance Prog SW-C	1.0000	64		64		64
74			PECO Com 303-LMR SW C	1.0000	85		85		85
75			PECO Com 303-MO New Bus. Portal SW	1.0000	39		39		39
76			PECO Com 3030-Apollo SW	1.0000	1,235	1,022	213	1,022	2,257
77			PECO Com 3030-BIDA-AMI Ph2 SW	1.0000	0		0		0
78			PECO Com 3030-Cloud Serv 3 yr	1.0000	176		176		176
79			PECO Com 3030-Cloud Serv 5 yr	1.0000	1,117	35	1,081	35	1,152
80			PECO Com 3030-Common MDM SW	1.0000	53		53		53
81			PECO Com 3030-EU Digital Program We	1.0000	387		387		387
82			PECO Com 3030-EU oneMDS SW	1.0000	993		993		993
83			PECO Com 3030-I Sign Up and Move	1.0000	89		89		89
84			PECO Com 3030-IT Cust Mobile App SW	1.0000	12		12		12
85			PECO Com 3030-IVR System PA	1.0000	41		41		41
86			PECO Com 3030-Misc 5 yr FR PA	1.0000	4,519	881	3,638	881	5,400
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88									
89			PECO Gas 3913 PA	1.0000					
90			Subtotal						
91									
92		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$1,138		$1,138		$1,138
93			PECO Gas 303-CC&B SW	1.0000	3,353		3,353		3,353
94			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	41		41		41
95			PECO Gas 303-SES IV G SW	1.0000	32		32		32
96			Subtotal Gas - Intangible Plant		$4,563		$4,563		$4,563
97									
98			Subtotal 404.0 Amort. Of Limited-Term Plant		$15,584	$2,232	$13,352	$2,232	$17,816
99									
100			Grand Total		**$124,658**	**$7,057**	**$117,602**	**$7,057**	**$131,715**

($ in Thousands)

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$857,032	$81,380	$938,412
2	Operating Expenses		602,946	791	603,737
3	OIBIT	L1 - L2	$254,086	$80,588	$334,674
4					
5	Rate Base		$4,002,182		$4,002,182
6	Weighted Cost of Debt		2.230%		2.230%
7	Synchronized Interest Expense	L5 * L6	$89,249		$89,249
8	Base Taxable Income	L3 - L7	$164,837	$80,588	$245,426
9					
10	State Accelerated Tax Depreciation		$98,977		$98,977
11	Pro Forma Book Depreciation		131,715		131,715
12	State Tax Depreciation (Over) Under Book	L11 - L10	$32,738		$32,738
13	Regulatory Asset Programs M-1, Pension & Post-Retirement & Other		(2,898)		(2,898)
14	Other Property Basis Adjustments (CIAC/ICM)		(35,210)		(35,210)
15	Removal Costs/Software		(4,042)		(4,042)
16	AFUDC Equity		-		-
17	Permanent Adjustments		715		715
18	Repair Deduction		(228,000)		(228,000)
19					
20	State Taxable Income	L8 + Sum L12 toL18	($71,860)	$80,588	$8,729
21					
22	State Income Tax Rate		6.99%	6.99%	6.99%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L20 * L22)	$5,023	($5,633)	($610)
24	Net Operating Loss Utilization %		60.00%	60.00%	60.00%
25	Net Operating Loss Utilization	- (L24 * L23)	(3,014)	3,380	366
26	State Income Tax Benefit / (Expense)	L23 + L25	$2,009	($2,253)	($244)
27					
28	Federal Accelerated Tax Depreciation		$96,777		$96,777
29	Pro Forma Book Depreciation		131,715		131,715
30	Federal Tax Deducts (Over) Under Book	L29 - L28	$34,938		$34,938
31	Regulatory Asset Programs M-1, Pension & Post-Retirement		(2,898)		(2,898)
32	Other Property Basis Adjustments (CIAC/ICM)		(40,154)		(40,154)
33	Removal Costs/Software		(4,042)		(4,042)
34	AFUDC Equity		-		-
35	Permanent Adjustments		715		715
36	Repair Deduction		(228,000)		(228,000)
37	Federal NOL				
38	Federal Taxable Income	L8 - L26 + Sum L30 to L37	($72,594)	$78,335	$5,741
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	- (L38 * L40)	$15,245	($16,450)	($1,206)
42	Corporate Alternative Minimum Tax				
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	$17,254	($18,704)	($1,450)
44					

($ in Thousands)

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($2,626)	$710	($1,916)
47	Deferred Taxes on Timing Differences- State		(2,664)		(2,664)
48	Deferred Taxes on State NOL		3,014	(3,380)	(366)
49	Excess Deferred Amortization		3,188		3,188
50	Excess Deferred Amortization - State (Net of Federal)		271		271
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax on Flow Through Adjustments		(8,359)		(8,359)
53	Corporate Alternative Minimum Tax				
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	($7,176)	($2,670)	($9,846)
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	$10,078	($21,374)	($11,296)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		($3)		($3)
60					
61	Combined Income Tax Benefit / (Expense)	L56 + L59	$10,076	($21,374)	($11,298)
62					
63	Federal Income Tax Benefit / (Expense)	L41 + L46 + L49 + L51 + L52 + L59	$7,445	($15,741)	($8,295)
64	State Income Tax Benefit / (Expense)	L26 + L47+ L48 + L50	$2,630	($5,633)	($3,003)
65	Total Income Tax Benefit / (Expense)	L63 + L64	**$10,076**	**($21,374)**	**($11,298)**

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		1,314
4	Total Customer Revenue		869,886
5	Shopping Revenue		94,341
6	LPC REVENUE	L3 / (L4 + L5)	0.001363
7	GROSS RECEIPTS TAX		
8	UNCOLLECTIBLE EXPENSES		(0.005231)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.004505)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.991627
13			
14	STATE INCOME TAX RATE		6.990%
15			
16	STATE INCOME TAX FACTOR	- L12 * L14	(0.069315)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.922313
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	- L18 * L20	(0.193686)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.728627
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.372444
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	26.300%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		6.990%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.069900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.930100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.195321)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.734779
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.360953
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	26.522%

PECO Exhibit MJT-2:
Principal Accounting Exhibit – FTY 2026

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2026
($ in Thousands)
A-1 Overall Summary

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Present Rates	Revenue Increase	Total
1	**MEASURE OF VALUE**				
2	Utility Plant	C-2	$4,967,773		$4,967,773
3	Accumulated Depreciation	C-3	1,090,763		1,090,763
4	Common Plant - Net of Accum Depr	C-8	199,048		199,048
5	Net Plant in service	L2 - L3 + L4	$4,076,057		$4,076,057
6					
7	Working Capital	C-1	$21,494		$21,494
8	Pension Assets / (Liability)	C-1	34,305		34,305
9	Accum Deferred Income Taxes	C-1	(261,829)		(261,829)
10	Customer Deposits	C-1	(14,323)		(14,323)
11	Customer Advances for Construction	C-1	(1,400)		(1,400)
12	Materials and Supplies	C-1	608		608
13	Accum Deferred Income Taxes - Reg Liability	C-1	(107,392)		(107,392)
14	Gas Storage	C-1	32,762		32,762
15					
16	TOTAL RATE BASE	SUM L5 to L14	$3,780,282		$3,780,282
17					
18	**OPERATING REVENUES AND EXPENSES**				
19	Base Customer Charges	D-5	$534,909	$64,832	$599,742
20	Supply Cost Revenue	D-5	283,907		283,907
21	Other Operating Revenues	D-5	5,078	93	5,171
22	Total Revenues	SUM L19 to L21	$823,895	$64,925	$888,820
23					
24	Operating Expenses	D-1	$579,978	$631	$580,609
25					
26	OIBIT	L22 - L24	$243,917	$64,294	$308,211
27					
28	Income Taxes @ Eff Inc Tax Rate	D-18	$12,652		$12,652
29	Income Taxes @ Statutory Rates	D-18		(17,306)	(17,306)
30					
31	NET OPERATING INCOME	SUM L26 to L29	$256,569	$46,988	$303,557
32					
33	RATE OF RETURN	L31 / L16	6.79%		8.03%
34					
35	**REVENUE INCREASE REQUIRED**				
36	Rate of Return at Present Rates	L33	6.79%		
37					
38	Rate of Return Required	B-7	8.03%		
39					
40	Change in ROR	L38 - L36	1.24%		
41					
42	Change in Operating Income	L16 * L40	$46,988		
43					
44	Gross Revenue Conversion Factor	D-19	1.380		
45					
46	Change in Revenues	L42 * L44	$64,832		
47					
48	**RETURN ON COMMON EQUITY**				
49	Common Equity Ratio	B-7	53.40%		
50	Common Equity Rate Base	L16 * L49	$2,018,671		
51	NET OPERATING INCOME	L31	$256,569		
52	Synchronized Interest Expense	D-18	$82,410		
53	NET OPERATING INCOME - COMMON EQUITY	L51 - L52	$174,159		
54	RATE OF RETURN ON COMMON EQUITY	L53 / L50	8.63%		

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$21,059,422
3	Construction Work In Progress (107)		1,220,330
4	Total Utility Plant	SUM L2 to L3	$22,279,752
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		4,653,056
6	Net Utility Plant	L4 - L5	$17,626,696
7			
8	**Other Property and Investments**		
9	Non-utility Property (121)		$14,745
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,599
11	Invest in Assoc Company (123)		7,258
12	Other Investments (124-129, 175-176)		38,062
13	Total Other Property and Investments	SUM L9 to L12	$58,466
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments(131-136)		$25,000
17	Customer Accounts Receivable (142)		670,914
18	Other Accounts Receivable (143)		32,249
19	Accum. Prov. for Uncollectible (144)		(158,892)
20	Receivables from Assoc. Comp. (146)		
21	Fuel Stock (151)		1,710
22	Plant Materials & Supplies (154)		90,271
23	Gas Stored - Current (164.1		44,585
24	Liquefied Natural Gas stored (164.2)		3,369
25	Prepayments (165)		73,503
26	Accrued Utility Revenues (173)		303,923
27	Miscellaneous Current & Accrued Assets (174)		2,920
28	Total Current and Accrued Assets	SUM L16 to L27	$1,089,553
29			
30	**Deferred Debits**		
31	Unamortized Debt Expense (181)		$59,895
32	Other Regualtory Assets (182.3)		1,576,512
33	Miscellaneous Deferred Debits (186)		898,338
34	Unamortized Loss on Reacquired Debt (189)		561
35	Accumulated Deferred Income Taxes (190)		0
36	Total Deferred Debits	SUM L31 to L35	$2,535,305
37			
38	**Total Assets**	L6 + L13 + L28 + L36	$21,310,020

($ in Thousands)

Line No.	Description	Reference (1)	Total - PECO (2)
39	**Proprietary Capital**		
40	Common Stock Issued (201)		$1,423,004
41	Preferred Stock Issued (204)		
42	Other Paid-In Capital (208-211)		4,396,960
43	Capital Stock Expense (214)		(87)
44	Retained Earnings (215, 215.2, 216)		2,671,097
45	Unappropriated Undistributed Subsidiary Earnings (216.1)		
46	Accum Other Comprehensive Income (219)		
47	Total Propriety Capital & Margins	SUM L40 to L46	$8,490,974
48			
49	**Long Term Debt**		
50	Bonds (221)		$7,225,000
51	Advances from Associated Companies (223)		184,419
52	Other Long-Term Debt (224)		
53	Unamortized Premium on LTD (225)		
54	Unamortized Discount on LTD (226)		(23,777)
55	Total Long-Term Debt	SUM L50 to L54	$7,385,642
56			
57	**Other Non-Current Liabilities**		
58	Obligations under Capital Leases (227)		
59	Accum. Prov for Injuries & Damages (228.2)		$62,513
60	Accum. Prov for Pensions & Benefits (228.3)		300,354
61	Accum. Miscellaneous Operating Prov (228.4)		11,729
62	Asset Retirement Obligation (230)		25,844
63	Total Other Non-Current Liabilities	SUM L58 to L62	$400,440
64			
65	**Current and Accrued Liabilities**		
66	Notes Payable (231)		$166,667
67	Accounts Payable (232)		776,814
68	Notes Payable to Assoc. Companies (233)		
69	Accounts Payable to Assoc. Companies (234)		22,766
70	Customer Deposits (235)		93,432
71	Taxes Accrued (236)		24,426
72	Interest Accrued (237)		92,818
73	Dividends Declared (238)		
74	Tax Collections Payable (241)		86
75	Misc Current & Accrued Liabilities (242)		158,156
76	Total Current & Accrued Liabilities	SUM L66 to L75	$1,335,166
77			
78	**Other Deferred Credits**		
79	Customer Advances for Construction (252)		$15,732
80	Other Deferred Credits (253)		8,645
81	Other Regulatory Liabilities (254)		565,616
82	Deferred Investment Tax Credit (255)		264
83	Unamortized Gain on Reacquired Debt (257)		
84	Accumulated Deferred Income Taxes (281-283)		3,107,542
85	Total Other Deferred Credits	SUM L79 to L84	$3,697,798
86			
87	**Total Liabilities and Other Credits**	L47 + L55 + L63 + L76 + L85	$21,310,020

($ in Thousands)

Line No.	Category	Description	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$552,516		$552,516
2		Gas Cost Revenue	283,907		283,907
3		Other Operating Revenues	25,078		25,078
4		Total Operating Revenues	$861,502		$861,502
5					
6	**Total Operating Expenses**	Operation & Maintenance Expenses	$462,115		$462,115
7		Depreciation & Amortization Expense	114,203		114,203
8		Amortization of Regulatory Expense	1,602		1,602
9		Taxes Other Than Income Taxes - Other	9,817		9,817
10		Total Operating Expenses	$587,737		$587,737
11					
12	**Net Utility Operating Income Before Income Tax**		$273,765		$273,765

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) FTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	480.0	$380,371		$380,371
2			C & I	481.0	139,691		139,691
3			Transportation of Gas of Others	489.3	32,454		32,454
4				Subtotal	$552,516		$552,516
5							
6		Gas Cost Revenue	Residential	480.0	$216,885		$216,885
7			C & I	481.0	67,023		67,023
8			Interdepartmental	484.0			
9				Subtotal	$283,907		$283,907
10							
11		Other Operating Revenues	Sales For Resale	483.0	$20,000		$20,000
12			Forfeited Discounts	487.0	1,328		1,328
13			Miscellaneous Service Revenues	488.0			
14			Rent for Gas Property	493.0	2,932		2,932
15			Interdepartmental Rents	494.0			
16			Other Gas Revenues	495.0	818		818
17				Subtotal	$25,078		$25,078
18							
19				**Total Operating Revenues**	$861,502		$861,502
20							
21	**Operating Expenses**	Operation & Maintenance Expenses	Manufactured Gas Production	710.0			
22			Liquefied Petroleum Gas Expenses	717.0	163		163
23			Liquefied Petroleum Gas Expenses	728.0	0		0
24			Maintenance of Structures and Improvements	741.0	109		109
25			Maintenance of Production Equipment	742.0	272		272
26			Natural Gas City Gate Purchases	804.0	298,907		298,907
27			Other Gas Purchases	805.0			
28			Purchases Gas Cost Adjustments	805.1			
29			Purchased Gas Expenses	807.0			
30			Gas Withdrawn from Storage-Debit	808.1			
31			Gas Delivered to Storage-Credit	808.2			
32			Other Gas Supply Purchases	813.0			
33			Other Expenses	824.0			
34			Operating Supervision and Engineering	840.0	444		444
35			Operation Labor and Expenses	841.0	1,076		1,076

($ in Thousands)

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FTY Amount	Non-Jurisdictional	Jurisdictional
36			Maintenance Supervision and Engineering	843.1	1,143		1,143
37			Maintenance of Structures and Improvements	843.2	4,441		4,441
38			Operation Supervision and Engineering	870.0	765		765
39			Mains and Services Expenses	874.0	20,130		20,130
40			Measuring and Regulating Station Expenses-General	875.0	1,273		1,273
41			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
42			Meter and House Regulator Expenses	878.0	6,003		6,003
43			Customer Installations Expenses	879.0	6,815		6,815
44			Other Expenses	880.0	19,089		19,089
45			Rents	881.0	22		22
46			Maintenance of Mains	887.0	17,331		17,331
47			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	724		724
48			Maintenance of Services	892.0	2,318		2,318
49			Maintenance of Meters & House Regulators	893.0	166		166
50			Maintenance of Other Equipment	894.0	606		606
51			Meter Reading	902.0	40		40
52			Customer Records and Collection	903.0	19,503		19,503
53			Uncollectible Accounts	904.0	2,419		2,419
54			Miscellaneous Customer Accounts	905.0	797		797
55			Customer Assistance	908.0	8,095		8,095
56			Informational & Instructional	909.0	652		652
57			Miscellaneous Customer & Informational	910.0			
58			Demonstrating & Selling	912.0	816		816
59			Miscellaneous Sales	916.0			
60			Administrative and General Salaries	920.0	7,433		7,433
61			Office Supplies and Expenses	921.0	705		705
62			Administrative Expenses Transferred-Credit	922.0			
63			Outside Service Employed	923.0	21,820		21,820
64			Property Insurance	924.0	204		204
65			Franchise Requirements	925.0	4,541		4,541
66			Employee Pensions and Benefits	926.0	8,956		8,956
67			Regulatory Commission Expenses	928.0	2,584		2,584
68			Duplicate Charges-Credit	929.0	(8)		(8)
69			Miscellaneous General Expenses	930.2	836		836
70			Maintenance of General Plant	932.0	929		929

($ in Thousands)

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FTY Amount	Non-Jurisdictional	Jurisdictional
71				Subtotal	$462,115		$462,115
72							
73			Depreciation & Amortization Expense	403.0	$98,050		$98,050
74				403.1			
75				404.0	16,153		16,153
76				Subtotal	$114,203		$114,203
77							
78			Amortization of Regulatory Expense	407.3	$1,602		$1,602
79				Subtotal	$1,602		$1,602
80							
81			Taxes Other Than Income Taxes - Other	408.1	$9,817		$9,817
82				Subtotal	$9,817		$9,817
83							
84				**Total Operating Expenses**	$587,737		$587,737
85							
86				**Net Utility Operating Income Before Income Tax**	$273,765		273,765

($ in Thousands)

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	480.0	$380,371		$380,371
2			C & I	481.0	139,691		139,691
3			Transportation of Gas of Others	489.3	32,454		32,454
4				Subtotal	$552,516		$552,516
5							
6		**Gas Cost Revenue**	Residential	480.0	$216,885		$216,885
7			C & I	481.0	67,023		67,023
8			Interdepartmental	484.0			
9				Subtotal	$283,907		$283,907
10							
11				OPERATING REVENUE	$836,424		$836,424
12							
13	**OTHER REVENUE**	**Other Operating Revenue**	Sales For Resale	483.0	$20,000		$20,000
14			Forfeited Discounts	487.0	$1,328		1,328
15			Miscellaneous Service Revenues	488.0			
16				Subtotal	$21,328		$21,328
17							
18		**Other Gas Revenue**	Rent for Gas Property	493.0	$2,932		$2,932
19			Interdepartmental Rents	494.0			
20			Other Gas Revenues	495.0	818		818
21				Subtotal	$3,750		$3,750
22							
23				OTHER REVENUE	$25,078		$25,078
24							
25				OTHER OPERATING REVENUES			
26							
27				**TOTAL**	**$861,502**		**$861,502**

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) Budget FTY	(2) Non-Jurisdictional	(3) Jurisdictional
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	Manufactured Gas Production	Manufactured Gas Production	710.0			
2			Liquefied Petroleum Gas Expenses	717.0	$163		$163
3			Maintenance of Structures and Improvements	741.0	109		109
4			Maintenance of Production Equipment	742.0	272		272
5				SUM L1 to L4	$544		$544
6							
7	**GAS RAW MATERIALS**	Gas Raw Materials	Liquefied Petroleum Gas Expenses	728.0	0		0
8							
9	**OTHER GAS SUPPLY EXPENSES**	Other Gas Supply	Natural Gas City Gate Purchases	804.0	$298,907		$298,907
10			Other Gas Purchases	805.0			
11			Purchases Gas Cost Adjustments	805.1			
12			Purchased Gas Expenses	807.0			
13			Gas Withdrawn from Storage-Debit	808.1			
14			Gas Delivered to Storage-Credit	808.2			
15			Other Gas Supply Purchases	813.0			
16				SUM L9 to L15	$298,907		$298,907
17							
18	**UNDERGROUND STORAGE EXPENSES**	Underground Storage Expenses	Other Expenses	824.0			
19							
20	**STORAGE EXPENSE**	Storage Operations Expense	Operating Supervision and Engineering	840.0	$444		$444
21			Operation Labor and Expenses	841.0	1,076		1,076
22				SUM L20 to L21	$1,520		$1,520
23							
24		Storage Maintenance Expense	Maintenance Supervision and Engineering	843.1	$1,143		$1,143
25			Maintenance of Structures and Improvements	843.2	4,441		4,441
26				SUM L24 to L25	$5,584		$5,584
27							
28			Subtotal STORAGE EXPENSE	L22 + L26	$7,104		$7,104
29							
30	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation Supervision and Engineering	870.0	$765		$765
31			Mains and Services Expenses	874.0	20,130		20,130
32			Measuring and Regulating Station Expenses-General	875.0	1,273		1,273
33			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
34			Meter and House Regulator Expenses	878.0	6,003		6,003
35			Customer Installations Expenses	879.0	6,815		6,815
36			Other Expenses	880.0	19,089		19,089
37			Rents	881.0	22		22
38				SUM L30 to L37	$54,095		$54,095
39							
40		Distribution Maintenance	Maintenance of Mains	887.0	$17,331		$17,331
41			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	724		724
42			Maintenance of Services	892.0	2,318		2,318
43			Maintenance of Meters & House Regulators	893.0	166		166
44			Maintenance of Other Equipment	894.0	606		606
45				SUM L40 to L44	$21,144		$21,144

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) Budget FTY	(2) Non-Jurisdictional	(3) Jurisdictional
46							
47			Subtotal DISTRIBUTION EXPENSE	L38 + L45	$75,240		$75,240
48							
49	**CUSTOMER ACCOUNTS**	Customer Accounts	Meter Reading	902.0	$40		$40
50			Customer Records and Collection	903.0	19,503		19,503
51			Uncollectible Accounts	904.0	2,419		2,419
52			Miscellaneous Customer Accounts	905.0	797		797
53			Subtotal CUSTOMER ACCOUNTS	SUM L49 to L52	$22,758		$22,758
54							
55	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$8,095		$8,095
56			Informational & Instructional	909.0	652		652
57			Miscellaneous Customer & Informational	910.0			
58			Subtotal CUSTOMER SERVICE & INFORMATION	SUM L55 to L57	$8,747		$8,747
59							
60	**SALES**	Sales	Demonstrating & Selling	912.0	$816		$816
61			Miscellaneous Sales	916.0			
62			Subtotal SALES	SUM L60 to L61	$816		$816
63							
64	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$7,433		$7,433
65			Office Supplies and Expenses	921.0	705		705
66			Administrative Expenses Transferred-Credit	922.0			
67			Outside Service Employed	923.0	21,820		21,820
68			Property Insurance	924.0	204		204
69			Injuries & Damages	925.0	4,541		4,541
70			Employee Pensions and Benefits	926.0	8,956		8,956
71			Regulatory Commission Expenses	928.0	2,584		2,584
72			Duplicate Charges-Credit	929.0	(8)		(8)
73			Miscellaneous General Expenses	930.2	836		836
74				SUM L64 to L73	$47,070		$47,070
75							
76		A&G Maintenance	Maintenance of General Plant	932.0	$929		$929
77							
78			Subtotal ADMINISTRATION & GENERAL	L74 + L76	$47,999		$47,999
79							
80			**Total**	.ines 5+10+16+28+47+53+58+62+78	$462,115		$462,115
81							
82			Total Operations Expense		$434,077		$434,077
83			Total Maintenance Expense		28,038		28,038
84			**Total O&M Expense**	L82 + L83	$462,115		$462,115

($ in Thousands)

		(1)	(2)
Line No.	Description	Total	Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,383	$2,383
2	Capital Stock & Franchise Tax		
3	Use Tax Accrued	817	817
4	Real Estate Tax Accrual	2,129	2,129
5	Miscellaneous TOTI		
6	Payroll Tax Accrued	4,489	4,603
7	**Total**	$9,817	$9,931

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effective Interest Rate	Average Weighted Cost Rate	Annualized Cost
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $575 - 4.90% - Due 6-15-2033		$575,000		5.03%		
2					7.76%		0.39%	
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		75,000		6.00%		
4					1.01%		0.06%	
5		PECO - FMB - $525 -4.875% - Due 9-15-2035		525,000		5.00%		
6					7.09%		0.35%	
7		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
8					4.05%		0.24%	
9		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
10					2.36%		0.14%	
11		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
12					3.37%		0.16%	
13		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.23%		
14					4.05%		0.17%	
15		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
16					4.39%		0.17%	
17		PECO - FMB - $325 - 3.90% - Due 3-1-2048		325,000		3.99%		
18					4.39%		0.18%	
19		PECO - FMB - $325 - 3.90% - Due 9-15-2048		325,000		4.17%		
20					4.39%		0.18%	
21		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
22					4.39%		0.14%	
23		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
24					4.72%		0.14%	
25		PECO - FMB - $375 - 3.05% - Due 3-1-2051		375,000		3.11%		
26					5.06%		0.16%	
27		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.91%		
28					5.06%		0.15%	
29		PECO - FMB - $350 - 4.60% - Due 6-1-2052		350,000		4.71%		
30					4.72%		0.22%	
31		PECO - FMB - $425 - 4.375% - Due 9-1-2052		425,000		4.46%		
32					5.74%		0.26%	
33		PECO - FMB - $575 - 5.25% - Due 9-15-54		575,000		5.34%		
34					7.76%		0.41%	
35		PECO - FMB - $525 - 5.65% - Due 9-15-55		525,000		5.72%		
36					7.09%		0.41%	
37		PECO - FMB - $750 - 5.80% - Due 8-1-56		750,000		5.87%		
38					10.12%		0.59%	
39								
40		Sub-Total Mortgage Bonds	SUM L1 to L38	$7,225,000	97.51%		4.52%	
41								
42	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.50%		
43					1.09%		0.08%	
44		PECO - TOPRS - $0.8 - Var (8.75%) - Due 4-6-2028		805		8.75%		
45					0.01%			
46		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
47					1.39%		0.08%	
48								
49		Sub-Total Capital Securities	SUM L42 to L47	$184,419	2.49%		0.16%	
50								
51		Total Long-Term Debt	L40 + L49	$7,409,419	100.00%		4.68%	
52								
53		Adjustments for Tenders & Calls		(453)				
54								
55		Net Long-Term Debt	L51 + L53	$7,408,966				
56								
57		Annualized Cost		346,761				
58								
59		Adjustment for Tenders & Calls Reacquired		68				
60								
61		**Total**	L57 + L59	$346,829				**4.68%**

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Capitalization	Capitalization Ratio	Embedded Cost	Return %
1					
2	Long-Term Debt	$7,408,966	46.60%	4.68%	2.18%
3					
4	Common Equity	$8,490,974	53.40%	10.95%	5.85%
5					
6	Total	**$15,899,940**	**100.00%**		**8.03%**

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	FTY Amount	Non-Jurisdictional	Jurisdictional
1	Utility Plant	C-2	$4,967,773		$4,967,773
2	Accumulated Depreciation	C-3	1,090,763		1,090,763
3	Common Plant	C-8	199,048		199,048
4	**Net Plant in Service**	L1 - L2 + L3	$4,076,057		$4,076,057
5					
6	Working Capital	C-4	$21,494		$21,494
7	Pension Assets / (Liability)	C-5	34,305		34,305
8	Accumulated Deferred Income Taxes	C-6	(261,829)		(261,829)
9	Customer Deposits	C-7	(14,323)		(14,323)
10	Customer Advances for Construction	C-9	(1,400)		(1,400)
11	Material & Supplies	C-11	608		608
12	ADIT - Reg Liability	C-12	(107,392)		(107,392)
13	Gas Storage	C-13	32,762		32,762
14	**Total Measures of Value**	SUM L4 to L13	$3,780,282		$3,780,282

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents		$50		$50
2		G303 - Intangible Property		45,517		45,517
3		Subtotal	SUM L1 to L2	$45,567		$45,567
4						
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements		$1,225		$1,225
6		G311 - Liquefied Petroleum Gas Equip.		14,452		14,452
7		Subtotal	SUM L5 to L6	$15,677		$15,677
8						
9	**Other Storage Plant**	G360 - Land and Land Rights		$16		$16
10		G361 - Structures & Improvements		15,140		15,140
11		G362 - Gas Holders		7,084		7,084
12		G363 - Gas Storage Equipment		126,103		126,103
13		Subtotal	SUM L9 to L12	$148,342		$148,342
14						
15	**Distribution Plant**	G374 - Land and Land Rights		$5,809		$5,809
16		G375 - Structures and Improvements		31,208		31,208
17		G376 - Gas Mains		2,623,476		2,623,476
18		G378 - Measure & Regulate Sta Equip		34,626		34,626
19		G379 - City Gate Station		110,362		110,362
20		G380 - Services		1,420,447		1,420,447
21		G381 - Meters		183,825		183,825
22		G382 - Meter Installations		300,956		300,956
23		G387 - Other Equipment		2,639		2,639
24		G388 - ARO Costs Distribution Plt		(244)	-	(244)
25		Subtotal	SUM L15 to L24	$4,713,103		$4,713,103
26						
27	**General Plant**	G390 - Structures & Improvements		$11,035		$11,035
28		G391 - Office Furniture & Equipment		4,181		4,181
29		G394 - Tools, Shop & Garage Equip		23,066		23,066
30		G395 - Laboratory Equipment		38		38
31		G397 - Communication Equipment		6,591		6,591
32		G398 - Miscellaneous Equipment		127		127
33		G399.1 - ARO Costs General Plt		45		45
34		Subtotal	SUM L27 to L33	$45,083		$45,083
35						
36		**Total**	Lines 3+7+13+25+34	**$4,967,773**		**$4,967,773**

($ in Thousands)

Line No.	Category	Account	(1) Additions to Plant
1	**Intangible Plant**	G303 - Intangible Property	$417
2		Subtotal Intangible Plant	$417
3			
4	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	18,643
12		Subtotal Other Storage Plant	$18,643
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	3,789
16		G376 - Gas Mains	195,451
17		G378 - Measure & Regulate Station Equipment	2,386
18		G379 - City Gate Station	28,123
19		G380 - Services	69,595
20		G381 - Meters	5,109
21		G382 - Meter Installations	13,410
22		G387 - Other Equipment	-
23		Subtotal Distribution Plant	$317,862
24			
25	**General Plant**	G390 - Structures & Improvements	$353
26		G391 - Office Furniture & Equipment	859
27		G394 - Tools, Shop & Garage Equipment	2,275
28		G395 - Laboratory Equipment	-
29		G397 - Communication Equipment	443
30		G398 - Miscellaneous Equipment	
31		Subtotal General Plant	$3,930
32			
33		**Total**	**$340,852**

($ in Thousands)

Line No.	Category	Account	(1) Plant Retirements
1	**Intangible Plant**	G303 - Intangible Property	($5,470)
2		Subtotal Intangible Plant	($5,470)
3			
4	**Manufactured Gas Pro**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	($53)
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	(1,720)
12		Subtotal Other Storage Plant	($1,774)
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	($54)
16		G376 - Gas Mains	(8,743)
17		G378 - Measure & Regulate Station Equipment	(114)
18		G379 - City Gate Station	-
19		G380 - Services	(4,439)
20		G381 - Meters	(233)
21		G382 - Meter Installations	(1,024)
22		G387 - Other Equipment	(42)
23		G388 - ARO Costs Distribution Plant	
24		Subtotal Distribution Plant	($14,648)
25			
26	**General Plant**	G390 - Structures & Improvements	($1)
27		G391 - Office Furniture & Equipment	(463)
28		G394 - Tools, Shop & Garage Equipment	(207)
29		G397 - Communication Equipment	(204)
30		G398 - Miscellaneous Equipment	-
31		G399.1 - ARO Costs General Plant	-
32		Subtotal General Plant	($875)
33			
34		**Total**	**($22,767)**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	FTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	G302 - Franchises & Consents	$50	100.00%	$50	100.00%	$50	
2			$50		$50		$50	
3								
4		G303 - Intangible Property	$45,517	100.00%	$45,517	100.00%	$45,517	
5			$45,517		$45,517		$45,517	
6								
7		Subtotal	**$45,567**		**$45,567**		**$45,567**	
8								
9	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$1,225	100.00%	$1,225	100.00%	$1,225	
10			$1,225		$1,225		$1,225	
11								
12		G311 - Liquefied Petroleum Gas Equip	$14,452	100.00%	$14,452	100.00%	$14,452	
13			$14,452		$14,452		$14,452	
14								
15		Subtotal	**$15,677**		**$15,677**		**$15,677**	
16								
17	**Other Storage Plant**	G360 - Land and Land Rights	$16	100.00%	$16	100.00%	$16	
18			$16		$16		$16	
19								
20		G361 - Structures & Improvements	$15,140	100.00%	$15,140	100.00%	$15,140	
21			$15,140		$15,140		$15,140	
22								
23		G362 - Gas Holders	$7,084	100.00%	$7,084	100.00%	$7,084	
24			$7,084		$7,084		$7,084	
25								
26		G363 - Gas Storage Equipment	$126,103	100.00%	$126,103	100.00%	$126,103	
27			$126,103		$126,103		$126,103	
28								
29		Subtotal	**$148,342**		**$148,342**		**$148,342**	
30								
31	**Distribution Plant**	G374 - Land and Land Rights	$5,809	100.00%	$5,809	100.00%	$5,809	
32			$5,809		$5,809		$5,809	
33								
34		G375 - Structures and Improvements	$31,208	100.00%	$31,208	100.00%	$31,208	
35			$31,208		$31,208		$31,208	
36								
37		G376 - Gas Mains	$2,623,476	100.00%	$2,623,476	100.00%	$2,623,476	
38			$2,623,476		$2,623,476		$2,623,476	
39								
40		G378 - Measure & Regulate Sta Equip	$34,626	100.00%	$34,626	100.00%	$34,626	
41			$34,626		$34,626		$34,626	
42								
43		G379 - City Gate Station	$110,362	100.00%	$110,362	100.00%	$110,362	
44			$110,362		$110,362		$110,362	
45								
46		G380 - Services	$1,420,447	100.00%	$1,420,447	100.00%	$1,420,447	
47			$1,420,447		$1,420,447		$1,420,447	
48								
49		G381 - Meters	$183,825	100.00%	$183,825	100.00%	$183,825	
50			$183,825		$183,825		$183,825	
51								
52		G382 - Meter Installations	$300,956	100.00%	$300,956	100.00%	$300,956	
53			$300,956		$300,956		$300,956	
54								
55		G387 - Other Equipment	$2,639	100.00%	$2,639	100.00%	$2,639	
56			$2,639		$2,639		$2,639	
57								
58		G388 - ARO Costs Distribution Plant	($244)	100.00%	($244)	100.00%	($244)	

($ in Thousands)

Line No.	Description	Account	(1) FTY Amount	(2) Utility Allocation Factor	(3) Allocated to Utility	(4) Jurisdictional Allocation Factor	(5) Allocated to Jurisdiction	(6) Allocated to Non Jurisdiction
59			($244)		($244)		($244)	
60								
61		Subtotal	**$4,713,103**		**$4,713,103**		**$4,713,103**	
62								
63	**General Plant**	G390 - Structures & Improvements	$11,035	100.00%	$11,035	100.00%	$11,035	
64			$11,035		$11,035		$11,035	
65								
66		G391 - Office Furniture & Equipment	$4,181	100.00%	$4,181	100.00%	$4,181	
67			$4,181		$4,181		$4,181	
68								
69		G394 - Tools, Shop & Garage Equip	$23,066	100.00%	$23,066	100.00%	$23,066	
70			$23,066		$23,066		$23,066	
71								
72		G395 - Laboratory Equipment	$38	100.00%	38	100.00%	38	
73			38		38		38	
74								
75		G397 - Communication Equipment	$6,591	100.00%	$6,591	100.00%	$6,591	
76			$6,591		$6,591		$6,591	
77								
78		G398 - Miscellaneous Equipment	$127	100.00%	$127	100.00%	$127	
79			$127		$127		$127	
80								
81		G399.1 - ARO Costs General Plant	$45	100.00%	$45	100.00%	$45	
82			$45		$45		$45	
83								
84		Subtotal	**$45,083**		**$45,083**		**$45,083**	
85								
86								
87		**Total**	**$4,967,773**		**$4,967,773**		**$4,967,773**	

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	FTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents				
2		G303 - Intangible Property		$17,709		$17,709
3		Subtotal Intangible Plant	SUM L1 to L2	$17,709		$17,709
4						
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements		$971		$971
6		G311 - Liquefied Petroleum Gas Equipment		13,185		13,185
7		Subtotal Manufactured Gas Production Plant	SUM L5 to L6	$14,155		$14,155
8						
9	**Other Storage Plant**	G360 - Land and Land Rights				
10		G361 - Structures & Improvements		$8,546		$8,546
11		G362 - Gas Holders		6,925		6,925
12		G363 - Gas Storage Equipment		21,380		21,380
13		Subtotal Other Storage Plant	SUM L9 to L12	$36,851		$36,851
14						
15	**Distribution Plant**	G374 - Land and Land Rights				
16		G375 - Structures and Improvements		$7,339		7,339
17		G376 - Gas Mains		447,606		447,606
18		G378 - Measure & Regulate Station Equipment		6,744		6,744
19		G379 - City Gate Station		29,525		29,525
20		G380 - Services		338,233		338,233
21		G381 - Meters		94,719		94,719
22		G382 - Meter Installations		76,762		76,762
23		G387 - Other Equipment		1,702		1,702
24		G388 - ARO Costs Distribution Plant		629		629
25		Subtotal Distribution Plant	SUM L15 to L24	$1,003,258		$1,003,258
26						
27	**General Plant**	G390 - Structures & Improvements		$4,025		$4,025
28		G391 - Office Furniture & Equipment		1,163		1,163
29		G394 - Tools, Shop & Garage Equipment		8,335		8,335
30		G395 - Laboratory Equipment		20		20
31		G397 - Communication Equipment		5,115		5,115
32		G398 - Miscellaneous Equipment		84		84
33		G399.1 - ARO Costs General Plant		47		47
34		Subtotal General Plant	SUM L27 to L33	$18,790		$18,790
35						
36		**Total**	Lines 3+7+13+25+34	**$1,090,763**		**$1,090,763**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Category	Account	FTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	G302 - Franchises & Consents						
2								
3		G303 - Intangible Property	$17,709	100.00%	$17,709	100.00%	$17,709	
4								
5		Subtotal	$17,709		$17,709		$17,709	
6								
7	**Distribution Plant**	G374 - Land and Land Rights		100.00%		100.00%		
8								
9		G375 - Structures and Improvements	7,339	100.00%	7,339	100.00%	7,339	
10								
11		G376 - Gas Mains	447,606	100.00%	447,606	100.00%	447,606	
12								
13		G378 - Measure & Regulate Sta Equip	6,744	100.00%	6,744	100.00%	6,744	
14								
15		G379 - City Gate Station	29,525	100.00%	29,525	100.00%	29,525	
16								
17		G380 - Services	338,233	100.00%	338,233	100.00%	338,233	
18								
19		G381 - Meters	94,719	100.00%	94,719	100.00%	94,719	
20								
21		G382 - Meter Installations	76,762	100.00%	76,762	100.00%	76,762	
22								
23		G387 - Other Equipment	1,702	100.00%	1,702	100.00%	1,702	
24								
25		G388 - ARO Costs Distribution Plant	629	100.00%	629	100.00%	629	
26								
27		Subtotal	**$1,003,258**		**$1,003,258**		**$1,003,258**	
28								
29	**General Plant**	G390 - Structures & Improvements	$4,025	100.00%	$4,025	100.00%	$4,025	
30								
31		G391 - Office Furniture & Equipment	1,163	100.00%	1,163	100.00%	1,163	
32								
33		G394 - Tools, Shop & Garage Equip	8,335	100.00%	8,335	100.00%	8,335	
34								
35		G395 - Laboratory Equipment	20	100.00%	20	100.00%	20	
36								
37		G397 - Communication Equipment	5,115	100.00%	5,115	100.00%	5,115	
38								
39		G398 - Miscellaneous Equipment	84	100.00%	84	100.00%	84	
40								
41		G399.1 - ARO Costs General Plant	47	100.00%	47	100.00%	47	
42								
43		Subtotal	**$18,790**		**$18,790**		**$18,790**	
44								
45	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$971	100.00%	$971	100.00%	$971	
46								
47		G311 - Liquefied Petroleum Gas Eqp	13,185	100.00%	13,185	100.00%	13,185	
48								
49		Subtotal	**$14,155**		**$14,155**		**$14,155**	
50								
51	**Other Storage Plant**	G360 - Land and Land Rights						
52								
53		G361 - Structures & Improvements	$8,546	100.00%	$8,546	100.00%	$8,546	
54								
55		G362 - Gas Holders	6,925	100.00%	6,925	100.00%	6,925	
56								
57		G363 - Gas Storage Equipment	21,380	100.00%	21,380	100.00%	21,380	
58								
59		Subtotal	**$36,851**		**$36,851**		**$36,851**	
60								
61		**Total**	**$1,090,763**		**$1,090,763**		**$1,090,763**	

($ in Thousands)

Line No.	Category	Account	(1) Reference	(2) FTY Amount
1	**Gas - Production Plant**	G305 - Structures and Improvements		
2		G311 - Liquefied Petroleum Gas Equipment		
3		Subtotal Gas - Production Plant	SUM L1 to L2	
4				
5	**Gas - Storage**	G361 - Structures & Improvements		($61)
6		G363 - Gas Storage Equipment		(1,120)
7		Subtotal Gas - Storage	SUM L5 to L6	($1,182)
8				
9	**Gas - Distribution**	G374 - Land and Land Rights		
10		G375 - Structures and Improvements		($46)
11		G376 - Gas Mains		(6,282)
12		G378 - Measure & Regulate Station Equipment		(470)
13		G379 - City Gate Station		(1)
14		G380 - Services		(2,866)
15		G381 - Meters		(1)
16		G382 - Meter Installations		(3,341)
17		G387 - Other Equipment		(10)
18		Subtotal Gas - Distribution	SUM L9 to L17	($13,018)
19				
20	**Gas - General Plant**	G390 - Structures & Improvements		($9)
21		G391 - Office Furniture & Equipment		(15)
22		G394 - Tools, Shop & Garage Equipment		-
23		G397 - Communication Equipment		(21)
24		Subtotal Gas - General Plant	SUM L20 to L23	($45)
25				
26		**Total**	Lines 3+7+18+24	**($14,245)**

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	FTY Expenses	(Lead)/Lag Days	Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			53.53	
4					
5	Expense Lag				
6	Payroll (Dist Only)		$50,069	13.56	$679,060
7	Pension Expense		914	(167.00)	(152,611)
8	Commodity Purchased - Gas		283,907	30.55	8,672,024
9	Payment to Suppliers		92,745	56.21	5,213,024
10	Other Expenses		109,139	43.21	4,715,523
11	Total O&M and POR Payments	SUM L6 to L10	$536,774		$19,127,020
12					
13	O&M Expense / POR Payment Lag Days			35.63	
14					
15	Net (Lead)/Lag Days	L3 - L13		17.90	
16					
17	Days in Current Year			365	
18					
19	Operating Expenses Per Day		$1,471		
20					
21	Working Capital for O&M Expense		$26,320		
22					
23	Average Prepayments		$2,593		
24	Accrued Taxes		1,101		
25	Interest Payments		(8,520)		
26					
27	Total Working Capital Requirement	SUM L21 to L25	$21,494		
28					
29	Pro Forma O&M Expense		$446,836		
30	Uncollectible Expense		2,807		
31	Pro Forma Cash O&M Expense	L29 - L30	$444,029		

($ in Thousands)

Line No.	Description	Reference (1)	Accounts Receivable Balance End of Month (2)	Total Monthly Billing Revenue (3)	A/R Turnover (4)	Days Lag (5)
1	Annual Number of Days					365
2						
3	December		$84,688			
4	January		133,726	$147,748		
5	February		145,270	147,778		
6	March		140,858	129,848		
7	April		118,807	81,256		
8	May		90,609	47,245		
9	June		83,001	38,897		
10	July		66,268	29,357		
11	August		56,882	28,650		
12	September		51,634	31,790		
13	October		49,213	37,052		
14	November		76,323	62,417		
15	December		115,675	130,449		
16						
17	Total	SUM L3 to L15	$1,212,954	$912,486		
18						
19	Average A/R Balance		13			
20						
21	Factor		$93,304	$912,486	9.78	37.32
22						
23	Collection Days Lag					37.32
24						
25	Billing and Revenue Recording Days Lag					1.00
26						
27	Billing Lag (Average Period)	365 / 12. * 0.5				15.21
28						
29	Total Revenue Lag Days	L23 + L25 + L27				**53.53**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Category	Description	Reference	Payment Date	Mid-point of Service Period	Expense Amount	(Lead)/Lag Days	Dollar Days
1	PAYROLL	Union & Non-Union Payroll				$48,828		
2		Paid Twice Per Month					13.56	
3		Weighted Payroll Dollar Value						$662,232
4								
5		Payroll Lag	SUM L1 to L3			48,828	13.56	$662,232
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2026	7/1/2026	$10,374	$ (167.00)	($1,732,458)
12								
13		Sub-Total	SUM L7 to L11			$10,374		($1,732,458)
14								
15		Lag Days for Pension Payment					$ (167.00)	
16								
17	PURCHASE COMMODITY COSTS	Payment Lag - Payment to Suppliers					56.21	
18								
19	OTHER O & M EXPENSES	March				$15,875		$656,144
20		June				18,479		697,875
21		September				36,511		1,651,476
22		December				35,501		1,590,220
23								
24		TOTAL	SUM L19 to L22			$106,366	43.21	$4,595,716

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Months	Description	Number of CDs	Cash Disbursements	Dollar-Days	Expense Lag Days
1	March	Total Disbursements for Month	33,074	$278,546		
2		Total Disbursements for Expenses	1,922	$15,875	$656,144	41.33
3						
4	June	Total Disbursements for Month	31,793	$240,494		
5		Total Disbursements for Expenses	1,904	$18,479	$697,875	37.77
6						
7	September	Total Disbursements for Month	38,855	$305,643		
8		Total Disbursements for Expenses	1,853	$36,511	$1,651,476	45.23
9						
10	December	Total Disbursements for Month	32,848	$369,705		
11		Total Disbursements for Expenses	2,215	$35,501	$1,590,220	44.79
12	**TOTAL FOUR TEST MONTHS**					
13						
14	Total Test Month Expense Disbursement		7,894	$106,366	$4,595,716	43.21

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Tax	Description	Payment Date	Mid Point Date	Lead/(Lag) Payment Days	Total Payment Amount	Payment Percentage	Payment Amount	Weighted Dollar Days
1	**FEDERAL INCOME TAX**	First Payment	4/15/2026	7/1/2026	77	($1,907)	25.00%	($477)	($36,718)
2		Second Payment	6/15/2026	7/1/2026	16	(1,907)	25.00%	(477)	(7,630)
3		Third Payment	9/15/2026	7/1/2026	(76)	(1,907)	25.00%	(477)	36,241
4		Fourth Payment	12/15/2026	7/1/2026	(167)	(1,907)	25.00%	(477)	79,636
5		Subtotal FEDERAL INCOME TAX					100.00%	($1,907)	$71,529
6									
7	**STATE INCOME TAX**	First Payment	3/16/2026	7/1/2026	107	($692)	25.00%	($173)	($18,507)
8		Second Payment	6/16/2026	7/1/2026	15	(692)	25.00%	(173)	(2,594)
9		Third Payment	9/15/2026	7/1/2026	(76)	(692)	25.00%	(173)	13,145
10		Fourth Payment	12/15/2026	7/1/2026	(167)	(692)	25.00%	(173)	28,884
11		Subtotal STATE INCOME TAX					100.00%	($692)	$20,928
12									
13	**PURTA**	First Payment	5/1/2026	7/1/2026	61	$2,383	100.00%	$2,383	$145,334
14		Subtotal PURTA					100.00%	$2,383	$145,334
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Subtotal PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/2/2026	7/1/2026	29	$2,129	100.00%	2,129	61,732
23		Second Payment							
24		Subtotal PA PROPERTY TAX					100.00%	2,129	61,732
25									
26	**GROSS RECEIPTS TAX**	First Payment							
27		Subtotal GROSS RECEIPTS TAX							

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Total Payment Amount	Weighted Dollar Days	Payment Lead/(Lag) Days	Revenue Lag Days	Net Payment Lead/(Lag) Days	Net Payment Lead/(Lag) Dollars Days	Average Daily Amount for Working Capital
1	FEDERAL INCOME TAX	($1,907)	$71,529	(37.50)	53.53	16.03	($30,577)	($84)
2	STATE INCOME TAX	($692)	$20,928	(30.25)	53.53	23.28	($16,106)	($44)
3	PURTA	$2,383	$145,334	61.00	53.53	114.53	$272,872	$748
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$2,129	$61,732	29.00	53.53	82.53	$175,682	$481
6	GROSS RECEIPTS TAX							

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Measures of Value at End of Test Year		$3,780,282
2	Long-Term Debt Ratio		46.60%
3	Embedded Cost of Long-Term Debt		4.68%
4	Pro Forma Interest Expense	L1 * L2 * L3	$82,443
5	Days in Current Year		365
6	Daily Amount	L4 / L5	$226
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days		53.53
9	Interest Payment Lag Days	L8 - L7	(37.72)
10	Total Interest for Working Capital	L6 * L9	**($8,520)**

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Description	Reference	AGA Membership Dues	EAP Membership Dues	Northeast Gas Assoc.	OTD Tech Development	Maintenance	IT License & Maintenance	PUC Assessment Gas	Prepaid Rent	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
1	December			$156			$23	$308	$1,335	$56	$3,449	$0	$27	$478	$172	$112	$566	
2	January			143		$130	15	219	973	39	3,449	(16)	14	498	166	232	580	
3	February			130		118	15	129	779	58	3,449	(32)	0	500	110	198	554	
4	March			117		106	15	40	584	42	2,376	150	0	503	82	439	538	
5	April			104		95	15	40	389	25	2,376	134	0	528	136	378	540	
6	May		$397	91		83	15	(50)	195	44	2,376	117	0	527	237	340	489	
7	June		397	78		71	15	(50)	0	28	1,888	100	0	530	484	302	499	
8	July		397	65		59	15	(50)	1,198	14	1,888	84	0	562	405	264	445	
9	August		91	52	$58	47	15	624	1,013	(3)	1,888	67	0	445	356	226	520	
10	September		67	39	43	35	15	624	2,128	71	2,231	50	0	471	306	188	655	
11	October		41	26	29	24	15	624	1,892	54	2,231	33	0	470	256	150	748	
12	November		15	13	14	12	15	624	1,655	39	2,231	17	0	500	318	112	748	
13	December		(24)				15	404	1,419	58	2,048	0	0	505	271	74	942	
14																		
15	Total	SUM L1 to L13	$1,382	$1,015	$144	$781	$205	$3,484	$13,558	$526	$31,883	$704	$41	$6,517	$3,299	$3,016	$7,825	
16																		
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23.02%	23.02%	23.02%	23.02%	25.48%	25.48%	25.48%	
18																		
19	Distribution Amount	L15 * L17	$1,382	$1,015	$144	$781	$205	$3,484	$13,558	$526	$7,339	$162	$9	$1,500	$841	$769	$1,994	
20																		
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																		
23	Monthly Average	L19 / L21	$106	$78	$11	$60	$16	$268	$1,043	$40	$565	$12	$1	$115	$65	$59	$153	
24																		
25	**Rate Case Amount**																	**$2,593**

		(1)	(2)	(3)
Line No.	Description	Shopping Percentage	Weighted Lag Days	Lag Days
1	Residential	57%		40.00
2	Nonresidential	43%		40.00
3	Weighted Payment Lag Days		40.00	
4				
5	Billing and Revenue Days Lag			1.00
6	Billing Lag (Average Period)			15.21
7	Total Payment Lag Days			56.21

		(1)	(2)
Line No.	Description	Reference	Pension Asset
1	Balance at End of HTY - Total		$441,490
2	Activities in FTY - Total		(1,509)
3	Balance at End of FTY - Total		$439,981
4	Allocation % to Utility		18.56%
5	Utility Amount	L4 * L5	$81,660
6	Allocation % to Distribution Capital		42.01%
7	Balance at End of FPFTY - Distribution Capital	L6 * L7	$34,305

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - CIAC		($4,716)	100.00%	($4,716)	100.00%	($4,716)
2		ADIT - Common Plant		106,546	100.00%	106,546	23.02%	24,527
3		ADIT - Gas Distribution		250,622	100.00%	250,622	100.00%	250,622
4		ADIT - Corporate Alternative Minimum Tax		(65,387)	100.00%	(65,387)	100.00%	(65,387)
5		Sub-Total	SUM L1 to L4	$287,064		$287,064		$205,045
6								
7	**FTY**	DIT - CIAC		$558	100.00%	$558	100.00%	$558
8		DIT - Common Plant		(7,346)	100.00%	(7,346)	23.02%	(1,691)
9		DIT - Gas Distribution		7,891	100.00%	7,891	100.00%	7,891
10		DIT - Corporate Alternative Minimum Tax		50,027	100.00%	50,027	100.00%	50,027
11		Sub-Total	SUM L7 to L10	$51,129		$51,129		$56,784
12								
13		**Total**	L5 + L11 + L17	$338,193		$338,193		$261,829

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Residential	Non-Residential	Total
1	December		$4,220	$8,545	$12,765
2	January		4,235	8,434	12,669
3	February		4,342	8,568	12,910
4	March		4,548	8,856	13,404
5	April		4,832	9,143	13,975
6	May		5,032	9,347	14,379
7	June		5,094	9,381	14,475
8	July		5,198	9,471	14,669
9	August		5,305	9,539	14,845
10	September		5,457	9,677	15,134
11	October		5,614	9,861	15,475
12	November		5,723	9,900	15,623
13	December		5,791	10,091	15,882
14					
15	Total	SUM L1 to L13	$65,392	$120,814	$186,205
16					
17	Average Monthly Balance	L15 / 13	$5,030	$9,293	$14,323
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$5,030
21	Small C&I				8,785
22	Large C&I				508
23	Transportation				
24					
25	Total	SUM L20 to L23			$14,323

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	FTY Amount	Allocated to Non Jurisdiction	Allocated to Jurisdiction
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$521	$156
4						
5		E303 - Misc Intangible Plant		$383,514	$297,595	$85,919
6						
7		E389 - Land and Land Rights		$6,770	$5,209	$1,560
8						
9		E390 - Structures and Improvements		$482,427	$371,372	$111,055
10		E391 - Office Furniture, Equipment		102,089	78,588	23,501
11		E392 - Transportation Equipment		244,211	187,994	56,217
12		E393 - Stores Equipment		2,187	1,684	504
13		E394 - Tools, Shop, Garage Equipmnt		2,788	2,146	642
14		E396 - Power Operated Equipment		870	670	200
15		E397 - Communication Equipment		141,134	108,645	32,489
16		E398 - Miscellaneous Equipment		665	512	153
17		E399 - Other Tangible Property				
18		E399.1 - ARO Costs General Plant		289	222	66
19		Sub Total - General Plant	SUM L9 to L18	$976,660	$751,833	$224,827
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,367,621	$1,055,159	$312,462
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$204,130	$157,139	$46,991
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$74,519	$57,364	$17,154
31		E391 - Office Furniture, Equipment		40,722	31,348	9,374
32		E392 - Transportation Equipment		114,663	88,268	26,395
33		E393 - Stores Equipment		540	416	124
34		E394 - Tools, Shop, Garage Equipmnt		1,312	1,010	302
35		E396 - Power Operated Equipment		325	250	75
36		E397 - Communication Equipment		56,170	43,239	12,930
37		E398 - Miscellaneous Equipment		683	525	157
38		E399 - Other Tangible Property				
39		E399.1 - ARO Costs General Plant		(384)	(295)	(88)
40		Sub Total - General Plant	SUM L30 to L39	$288,548	$222,124	$66,424
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$492,678	$379,264	$113,414
42						
43		Net Common Plant	L20 - L41	**$874,943**	**$675,896**	**$199,048**
44						
45						
46		Common Plant in Service to Utility	L20	$1,367,621	$1,055,159	$312,462
47		Common Plant Accum Depreciation to Utility	L41	492,678	379,264	113,414
48		Net Common Plant to Utility	L46 - L47	$874,943	$675,896	$199,048

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2026
($ in Thousands)
C-9 Customer Advances For Construction

Line No.	Description	(1) Total FTY Amount
1	HTY 13-Month Average	
2	December	$964
3	January	1,037
4	February	1,033
5	March	1,043
6	April	1,198
7	May	1,270
8	June	1,295
9	July	1,436
10	August	1,480
11	September	1,480
12	October	1,981
13	November	1,974
14	December	2,014
15		
16	13-Month Total	$18,204
17		
18		
19	Average Monthly Balance	**$1,400**

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Materials & Supplies	Undistributed Stores Expense	Total
1	HTY 13-Month Average				
2	December		$552	$0	$552
3	January		577	(535)	42
4	February		559	(319)	240
5	March		588	(560)	28
6	April		602	(2,433)	(1,831)
7	May		595	(911)	(316)
8	June		952	(1,049)	(97)
9	July		965	(1,747)	(782)
10	August		856	(2,066)	(1,209)
11	September		1,438	(2,581)	(1,143)
12	October		1,396	(2,857)	(1,462)
13	November		1,423	(2,421)	(998)
14	December		1,432	0	1,432
15					
16	Total	SUM L2 to L14	$11,934	($17,478)	($5,544)
17					
18	Distribution Expense Allocation Factor		100.00%	23.02%	
19					
20	Allocation to Distribution	L16 * L18	$11,934	($4,023)	
21					
22	Average Monthly Balance	L20 / 13	$918	($309)	**$608**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - Distribution		$109,004	100.00%	$109,004	100.00%	$109,004
2		ADIT - CIAC			100.00%		100.00%	
3		Subtotal HTY	L1 + L2	109,004		109,004		109,004
4								
5	**FTY**	DIT - Distribution		($1,612)	100.00%	($1,612)	100.00%	($1,612)
6		DIT - CIAC			100.00%		100.00%	
7		Subtotal FTY	L5 + L6	($1,612)		($1,612)		($1,612)
8								
9		**Total**	L3 + L7 + L11	$107,392		$107,392		**$107,392**

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	Stored Underground	LNG	Propane Gas	Total
1	December		$31,540	$3,928	$1,527	$36,995
2	January		21,596	3,071	1,527	26,195
3	February		13,954	2,966	1,481	18,401
4	March		10,871	2,907	1,481	15,259
5	April		11,311	2,857	1,481	15,649
6	May		16,991	2,804	1,481	21,276
7	June		22,340	3,219	1,481	27,041
8	July		28,648	3,738	1,570	33,956
9	August		35,448	4,008	1,710	41,166
10	September		40,349	3,962	1,710	46,021
11	October		44,863	3,912	1,710	50,485
12	November		44,665	3,873	1,710	50,247
13	December		37,749	3,774	1,693	43,216
14						
15	Total	SUM L1 to L13	$360,324	$45,018	$20,564	$425,907
16						
17	Average Monthly Balance	L15 / 13	$27,717	$3,463	$1,582	**$32,762**

($ in Thousands)

Line No.	Category	Description	(1) Reference	(2) Pro Forma Adjusted at Present Rates	(3) Proposed Rate Increase	(4) Adjusted Amounts with Proposed Rate Increase
1	**Operating Revenues**	Residential		$583,564		$583,564
2		C & I		203,088		203,088
3		Interdepartmental				
4		Sales for Resale				
5		Forfeited Discounts		1,328	93	1,420
6		Miscellaneous Service Revenues				
7		Rent For Gas Property		2,932		2,932
8		Other Gas Revenues		805		805
9		Transportation of Gas of Others		32,177		32,177
10		Revenue Increase			64,832	64,832
11		Subtotal Operating Revenues	SUM L1 to L10	$823,895	$64,925	$888,820
12						
13	**Operating Expenses**	Manufactured Gas Production		$549		$549
14		Storage Operations Expense		1,540		1,540
15		Storage Maintenance Expense		5,644		5,644
16		Underground Storage Expenses				
17		Other Gas Supply		283,907		283,907
18		Distribution Expense		73,810		73,810
19		Total Customer Accounts		24,006	339	24,345
20		Total Customer Service & Information		8,751		8,751
21		Total Sales		824		824
22		Administrative & General		47,806	292	48,098
23		O&M Expense	SUM L13 to L22	$446,836	$631	$447,468
24						
25		Depreciation & Amortization Expense		$121,138		$121,138
26		Amortization of Regulatory Expense		2,072		2,072
27		Taxes Other Than Income Taxes - Other		9,931		9,931
28		Subtotal Operating Expenses	SUM L23 to L27	$579,978	$631	$580,609
29						
30	**Net Operating Income - BIT**		L11 - L28	$243,917	$64,294	$308,211

($ in Thousands)

			(1)	(2)	(3)
Line No.	Category	Description	FTY Amount Pre Adjustments	Adjustments Sub-Total	Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	$597,256	($13,691)	$583,564
2		C & I	206,714	(3,626)	203,088
3		Interdepartmental			
4		Sales for Resale	20,000	(20,000)	
5		Forfeited Discounts	1,328		1,328
6		Miscellaneous Service Revenues			
7		Rent For Gas Property	2,932		2,932
8		Other Gas Revenues	818	(13)	805
9		Transportation of Gas of Others	32,454	(277)	32,177
10		Revenue Increase			
11		Subtotal Operating Revenues	$861,502	($37,607)	$823,895
12					
13	**Operating Expenses**	Manufactured Gas Production	$544	$5	$549
14		Storage Operations Expense	1,520	19	1,540
15		Storage Maintenance Expense	5,584	61	5,644
16		Underground Storage Expenses			
17		Other Gas Supply	298,907	(15,000)	283,907
18		Distribution Expense	75,240	(1,430)	73,810
19		Total Customer Accounts	22,758	1,248	24,006
20		Total Customer Service & Information	8,747	4	8,751
21		Total Sales	816	8	824
22		Administrative & General	47,999	(194)	47,806
23		O&M Expense	$462,115	($15,278)	$446,836
24					
25		Depreciation & Amortization Expense	$114,203	$6,935	$121,138
26		Amortization of Regulatory Expense	1,602	470	2,072
27		Taxes Other Than Income Taxes - Other	9,817	114	9,931
28		Subtotal Operating Expenses	$587,737	($7,759)	$579,978
29					
30	**Net Operating Income - BIT**		**$273,765**	**($29,848)**	**$243,917**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending Dec. 2026
($ in Thousands)
D-3 Adj.'s to Net Operating Income

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Category	Description	Description	FTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Leap Year Adjustment	D-5E Weather Normalization	D-5E Asset Optimization - Margin Adjustment	D-5F Weather Normal Adjustment	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits
1	**Operating Revenues**	Residential	Gas Cost	$216,885									
2			Cust & Dist	380,371	878	(184)	423			(14,809)			
3			Subtotal Residential	$597,256	$878	($184)	$423			($14,809)			
4													
5		C & I	Gas Cost	$67,023									
6			Cust & Dist	139,691	490		166			(4,282)			
7			Subtotal C & I	$206,714	$490		$166			($4,282)			
8													
9		Interdepartmental	Gas Cost										
10			Subtotal Interdepartmental										
11													
12		Sales for Resale	Sales For Resale	$20,000					(20,000)				
13			Subtotal Sales for Resale	$20,000					($20,000)				
14													
15		Forfeited Discounts	Forfeited Discounts	$1,328									
16			Subtotal Forfeited Discounts	$1,328									
17													
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues										
19			Subtotal Miscellaneous Service Revenues										
20													
21		Rent For Gas Property	Rent for Gas Property	$2,932									
22			Subtotal Rent For Gas Property	$2,932									
23													
24		Other Gas Revenues	Other Gas Revenues	$818						(13)			
25			Subtotal Other Gas Revenues	$818						($13)			
26													
27		Transportation of Gas of Others	Transportation of Gas of Others	$32,454						(277)			
28			Subtotal Transportation of Gas of Others	$32,454						($277)			
29													
30		Revenue Increase	Revenue Increase										
31			Subtotal Revenue Increase										
32													
33			**Total Operating Revenues**	**$861,502**	**$1,368**	**($184)**	**$589**		**($20,000)**	**($19,381)**			
34													
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production										
36			Liquefied Petroleum Gas Expenses	163							2		
37			Liquefied Petroleum Gas Expenses	0									
38			Maintenance of Structures and Improvements	109							1		
39			Maintenance of Production Equipment	272							3		
40			Subtotal Manufactured Gas Production	$544							$5		
41													
42		Other Gas Supply	Natural Gas City Gate Purchases	$298,907					(15,000)				
43			Other Gas Purchases										
44			Purchases Gas Cost Adjustments										
45			Purchased Gas Expenses										

($ in Thousands)

Line No.	Category	Description	Description	(1) FTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-5F Weather Normal Adjustment	(8) D-6 Salary & Wages	(9) D-7 Rate Case Expense	(10) D-8 Adjustments for Employee Benefits
46			Gas Withdrawn from Storage-Debit										
47			Gas Delivered to Storage-Credit										
48			Other Gas Supply Purchases										
49			Subtotal Other Gas Supply	$298,907					($15,000)				
50													
51		Storage Maintenance Expense	Maintenance Supervision and Engineering	$1,143							$14		
52			Maintenance of Structures and Improvements	4,441							47		
53			Subtotal Storage Maintenance Expense	$5,584							$61		
54													
55		Storage Operations Expense	Operating Supervision and Engineering	$444							$6		
56			Operation Labor and Expenses	1,076							14		
57			Subtotal Storage Operations Expense	$1,520							$19		
58													
59		Underground Storage Expenses	Other Expenses										
60			Subtotal Underground Storage Expenses										
61													
62		Distribution Expense	Operation Supervision and Engineering	$765							$0		
63			Mains and Services Expenses	20,130							$212		
64			Measuring and Regulating Station Expenses-General	1,273							$22		
65			Measuring and Regulating Station Expenses-City Gate	0									
66			Meter and House Regulator Expenses	6,003							$53		
67			Customer Installations Expenses	6,815							$122		
68			Other Expenses	19,089							$111		
69			Rents	22									
70			Maintenance of Mains	17,331							$194		
71			Maintenance of Measuring & Reg. Station Equip.-Genl.	724							$10		
72			Maintenance of Services	2,318							$29		
73			Maintenance of Meters & House Regulators	166							$3		
74			Maintenance of Other Equipment	606							$2		
75			Subtotal Distribution Expense	$75,240							$758		
76													
77		Total Customer Accounts	Customer Records and Collection	$19,503							$163		
78			Meter Reading	40									
79			Miscellaneous Customer Accounts	797							$8		
80			Uncollectible Accounts	2,419									
81			Subtotal Total Customer Accounts	$22,758							$171		
82													
83		Total Customer Service & Information	Customer Assistance	$8,095							$4		
84			Informational & Instructional	652									
85			Miscellaneous Customer & Informational										
86			Subtotal Total Customer Service & Information	$8,747							$4		
87													
88		Total Sales	Demonstrating & Selling	$816							$8		
89			Miscellaneous Sales										
90			Subtotal Total Sales	$816							$8		

($ in Thousands)

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Category	Description	Description	FTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Leap Year Adjustment	D-5E Weather Normalization	D-5E Asset Optimization - Margin Adjustment	D-5F Weather Normal Adjustment	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits
91													
92		Administrative & General	Administrative and General Salaries	$7,433							$207		
93			Administrative Expenses Transferred-Credit										
94			Duplicate Charges-Credit	(8)									
95			Employee Pensions and Benefits	8,956									(38)
96			Franchise Requirements										
97			Injuries and Damages	4,541							$4		
98			Maintenance of General Plant	929							$4		
99			Miscellaneous General Expenses	836							$0		
100			Office Supplies and Expenses	705									
101			Outside Service Employed	21,820									
102			Property Insurance	204									
103			Regulatory Commission Expenses	2,584									
104			Subtotal Administrative & General	$47,999							$215		($38)
105													
106			**O&M Expense**	**$462,115**					**($15,000)**		**$1,241**		**($38)**
107													
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$114,203									
109			Subtotal Depreciation & Amortization Expense	$114,203									
110													
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense	$1,602									
112			Subtotal Amortization of Regulatory Expense	$1,602									
113													
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$9,817									
115			Subtotal Taxes Other Than Income Taxes - Other	$9,817									
116													
117			**Total Operating Expenses**	**$587,737**					**($15,000)**		**$1,241**		**($38)**
118													
119	**Net Operating Income Before Income Tax**			**$273,765**	**$1,368**	**($184)**	**$589**		**($5,000)**	**($19,381)**	**($1,241)**		**$38**

($ in Thousands)

				(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Line No.	Category	Description	Description	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 Energy Efficiency	D-12 Customer Deposit Interest	D-13 MGP Recovery	D-14 MGP Interest	D-15 GPC / MFC	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Gas Cost											$216,885
2			Cust & Dist										($13,691)	366,679
3			Subtotal Residential										($13,691)	$583,564
4														
5		C & I	Gas Cost											$67,023
6			Cust & Dist										($3,626)	136,066
7			Subtotal C & I										($3,626)	$203,088
8														
9		Interdepartmental	Gas Cost											
10			Subtotal Interdepartmental											
11														
12		Sales for Resale	Sales For Resale										($20,000)	
13			Subtotal Sales for Resale										($20,000)	
14														
15		Forfeited Discounts	Forfeited Discounts											$1,328
16			Subtotal Forfeited Discounts											$1,328
17														
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues											
19			Subtotal Miscellaneous Service Revenues											
20														
21		Rent For Gas Property	Rent for Gas Property											2,932
22			Subtotal Rent For Gas Property											2,932
23														
24		Other Gas Revenues	Other Gas Revenues										($13)	$805
25			Subtotal Other Gas Revenues										($13)	$805
26														
27		Transportation of Gas of Others	Transportation of Gas of Others										($277)	$32,177
28			Subtotal Transportation of Gas of Others										($277)	$32,177
29														
30		Revenue Increase	Revenue Increase											
31			Subtotal Revenue Increase											
32														
33			**Total Operating Revenues**										**($37,607)**	**$823,895**
34														
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production											
36			Liquefied Petroleum Gas Expenses										$2	165
37			Liquefied Petroleum Gas Expenses											0
38			Maintenance of Structures and Improvements										$1	110
39			Maintenance of Production Equipment										$3	274
40			Subtotal Manufactured Gas Production										$5	$549
41														
42		Other Gas Supply	Natural Gas City Gate Purchases										($15,000)	$283,907
43			Other Gas Purchases											
44			Purchases Gas Cost Adjustments											
45			Purchased Gas Expenses											

($ in Thousands)

				(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Line No.	Category	Description	Description	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 Energy Efficiency	D-12 Customer Deposit Interest	D-13 MGP Recovery	D-14 MGP Interest	D-15 GPC / MFC	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
46			Gas Withdrawn from Storage-Debit											
47			Gas Delivered to Storage-Credit											
48			Other Gas Supply Purchases											
49			Subtotal Other Gas Supply										($15,000)	$283,907
50														
51		Storage Maintenance Expense	Maintenance Supervision and Engineering										$14	$1,157
52			Maintenance of Structures and Improvements										$47	4,487
53			Subtotal Storage Maintenance Expense										$61	$5,644
54														
55		Storage Operations Expense	Operating Supervision and Engineering										$6	$450
56			Operation Labor and Expenses										$14	1,090
57			Subtotal Storage Operations Expense										$19	$1,540
58														
59		Underground Storage Expenses	Other Expenses											
60			Subtotal Underground Storage Expenses											
61														
62		Distribution Expense	Operation Supervision and Engineering										$0	$765
63			Mains and Services Expenses										$212	20,342
64			Measuring and Regulating Station Expenses-General										$22	1,294
65			Measuring and Regulating Station Expenses-City Gate											0
66			Meter and House Regulator Expenses										$53	6,055
67			Customer Installations Expenses										$122	6,937
68			Other Expenses							(2,188)			($2,077)	17,012
69			Rents											22
70			Maintenance of Mains										$194	17,525
71			Maintenance of Measuring & Reg. Station Equip.-Genl.										$10	734
72			Maintenance of Services										$29	2,347
73			Maintenance of Meters & House Regulators										$3	168
74			Maintenance of Other Equipment										$2	607
75			Subtotal Distribution Expense							($2,188)			($1,430)	$73,810
76														
77		Total Customer Accounts	Customer Records and Collection										$163	$19,666
78			Meter Reading											40
79			Miscellaneous Customer Accounts				684		$4				$696	1,493
80			Uncollectible Accounts		2,349					(1,961)			$388	2,807
81			Subtotal Total Customer Accounts		$2,349		$684		$4	($1,961)			$1,248	$24,006
82														
83		Total Customer Service & Information	Customer Assistance										$4	$8,099
84			Informational & Instructional											652
85			Miscellaneous Customer & Informational											
86			Subtotal Total Customer Service & Information										$4	$8,751
87														
88		Total Sales	Demonstrating & Selling										$8	$824
89			Miscellaneous Sales											
90			Subtotal Total Sales										$8	$824

($ in Thousands)

				(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Line No.	Category	Description	Description	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 Energy Efficiency	D-12 Customer Deposit Interest	D-13 MGP Recovery	D-14 MGP Interest	D-15 GPC / MFC	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
91														
92		Administrative & General	Administrative and General Salaries										$207	$7,640
93			Administrative Expenses Transferred-Credit											
94			Duplicate Charges-Credit											(8)
95			Employee Pensions and Benefits	(370)									($408)	8,548
96			Franchise Requirements											
97			Injuries and Damages										$4	4,544
98			Maintenance of General Plant										$4	933
99			Miscellaneous General Expenses										$0	836
100			Office Supplies and Expenses											705
101			Outside Service Employed											21,820
102			Property Insurance											204
103			Regulatory Commission Expenses											2,584
104			Subtotal Administrative & General	($370)									($194)	$47,806
105														
106			**O&M Expense**	**($370)**	**$2,349**		**$684**		**$4**	**($4,149)**			**($15,278)**	**$446,836**
107														
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense									$6,935	$6,935	$121,138
109			Subtotal Depreciation & Amortization Expense									$6,935	$6,935	$121,138
110														
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense			$438		$32					$470	$2,072
112			Subtotal Amortization of Regulatory Expense			$438		$32					$470	$2,072
113														
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other								$114		$114	$9,931
115			Subtotal Taxes Other Than Income Taxes - Other								$114		$114	$9,931
116														
117			**Total Operating Expenses**	**($370)**	**$2,349**	**$438**	**$684**	**$32**	**$4**	**($4,149)**	**$114**	**$6,935**	**($7,759)**	**$579,978**
118														
119	**Net Operating Income Before Income Tax**			**$370**	**($2,349)**	**($438)**	**($684)**	**($32)**	**($4)**	**$4,149**	**($114)**	**($6,935)**	**($29,848)**	**$243,917**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2026
($ in Thousands)
D-4 Expense Adjustment Summary

Line No.	Category	Description	Account	(1) FTY Amount Pre Adjustments	(2) D-5E Asset Optimization - Margin Adjustment	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 Energy Efficiency
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.								
2			717.0 Liquefied Petroleum Gas Expenses.	163		2					
3			741.0 Maintenance Of Structures And Improvements.	109		1					
4			742.0 Maintenance Of Production Equipment.	272		3					
5			Subtotal	$544		$5					
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.	0							
8			Subtotal	$0							
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.	$298,907	($15,000)						
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								
13			807.0 Purchased Gas Expenses.								
14			808.1 Gas Withdrawn From Storage-Debit.								
15			808.2 Gas Delivered To Storage-Credit.								
16			813.0 Other Gas Supply Expenses.								
17			Subtotal	$298,907	($15,000)						
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.	$444		$6					
23			841.0 Operation Labor And Expenses.	1,076		14					
24			Subtotal	$1,520		$19					
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.	$1,143		$14					
27			843.2 Maintenance Of Structures And Improvements.	4,441		47					
28			Subtotal	$5,584		$61					
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.	$765		$0					
31			874.0 Mains And Services Expenses.	20,130		212					
32			875.0 Measuring And Regulating Station Expenses--General.	1,273		22					
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.	0							
34			878.0 Meter And House Regulator Expenses.	6,003		53					
35			879.0 Customer Installations Expenses.	6,815		122					
36			880.0 Other Expenses.	19,089		111					
37			881.0 Rents.	22							
38			Subtotal	$54,095		$520					
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.	$17,331		$194					
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	724		10					
42			892.0 Maintenance Of Services.	2,318		29					
43			893.0 Maintenance Of Meters And House Regulators.	166		3					
44			894.0 Maintenance Of Other Equipment.	606		2					
45			Subtotal	$21,144		$238					
46											
47			Distribution Expense Subtotal	$75,240		$758					
48											

($ in Thousands)

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Category	Description	Account	FTY Amount Pre Adjustments	D-5E Asset Optimization - Margin Adjustment	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 Energy Efficiency
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.	$40		$0					
50			903.0 Customer Records And Collection Expenses.	19,503		163					
51			904.0 Uncollectible Accounts.	2,419						2,349	
52			905.0 Miscellaneous Customer Accounts Expenses.	797		8					
53											
54			Subtotal	$22,758		$171				$2,349	
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses	$8,095		$4					
57			909.0 Informational And Instructional Advertising Expenses.	652							
58			910.0 Miscellaneous Customer Service And Informational Expenses.								
59			Subtotal	$8,747		$4					
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.	$816		$8					
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal	$816		$8					
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.	$7,433		$207					
66			921.0 Office Supplies And Expenses.	705							
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.	21,820							
69			924.0 Property Insurance.	204							
70			925.0 Injuries And Damages.	4,541		4					
71			926.0 Employee Pensions And Benefits.	8,956				(38)	(370)		
72			928.0 Regulatory Commission Expenses.	2,584							
73			929.0 Duplicate Charges--Credit.	(8)							
74			930.2 Miscellaneous General Expenses.	836		0					
75											
76			Subtotal	$47,070		$210		($38)	($370)		
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.	$929		$4					
79			Subtotal	$929		$4					
80											
81			A&G Expense Sub-total	$47,999		$215		($38)	($370)		
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$98,050							
84			403.1 Depreciation Expense - ARO/FIN-47								
85			404.0 Amort. Of Limited-Term Plant	16,153							
86			Subtotal	$114,203							
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.	$1,602							$438
89			Subtotal	$1,602							$438
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$9,817							
92			Subtotal	$9,817							
93											
94			**Total**	**$587,737**	**($15,000)**	**$1,241**		**($38)**	**($370)**	**$2,349**	**$438**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2026
($ in Thousands)
D-4 Expense Adjustment Summary

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.								
2			717.0 Liquefied Petroleum Gas Expenses.							2	165
3			741.0 Maintenance Of Structures And Improvements.							1	110
4			742.0 Maintenance Of Production Equipment.							3	274
5			Subtotal							$5	$549
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.								0
8			Subtotal								$0
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.							($15,000)	$283,907
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								
13			807.0 Purchased Gas Expenses.								
14			808.1 Gas Withdrawn From Storage-Debit.								
15			808.2 Gas Delivered To Storage-Credit.								
16			813.0 Other Gas Supply Expenses.								
17			Subtotal							($15,000)	$283,907
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.							$6	$450
23			841.0 Operation Labor And Expenses.							14	1,090
24			Subtotal							$19	$1,540
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.							$14	$1,157
27			843.2 Maintenance Of Structures And Improvements.							47	4,487
28			Subtotal							$61	$5,644
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.							$0	$765
31			874.0 Mains And Services Expenses.							212	20,342
32			875.0 Measuring And Regulating Station Expenses--General.							22	1,294
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.								0
34			878.0 Meter And House Regulator Expenses.							53	6,055
35			879.0 Customer Installations Expenses.							122	6,937
36			880.0 Other Expenses.				(2,188)			(2,077)	17,012
37			881.0 Rents.								22
38			Subtotal				($2,188)			($1,668)	$52,427
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.							$194	$17,525
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.							10	734
42			892.0 Maintenance Of Services.							29	2,347
43			893.0 Maintenance Of Meters And House Regulators.							3	168
44			894.0 Maintenance Of Other Equipment.							2	607
45			Subtotal							$238	$21,382
46											
47			Distribution Expense Subtotal				($2,188)			($1,430)	$73,810
48											

($ in Thousands)

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.							$0	$40
50			903.0 Customer Records And Collection Expenses.							163	19,666
51			904.0 Uncollectible Accounts.				(1,961)			388	2,807
52			905.0 Miscellaneous Customer Accounts Expenses.	684		$4				696	1,493
53											
54			Subtotal	$684		$4	($1,961)			$1,248	$24,006
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses							$4	$8,099
57			909.0 Informational And Instructional Advertising Expenses.								652
58			910.0 Miscellaneous Customer Service And Informational Expenses.								
59			Subtotal							$4	$8,751
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.							$8	$824
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal							$8	$824
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.							$207	$7,640
66			921.0 Office Supplies And Expenses.								705
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.								21,820
69			924.0 Property Insurance.								204
70			925.0 Injuries And Damages.							4	4,544
71			926.0 Employee Pensions And Benefits.							(408)	8,548
72			928.0 Regulatory Commission Expenses.								2,584
73			929.0 Duplicate Charges--Credit.								(8)
74			930.2 Miscellaneous General Expenses.							0	836
75											
76			Subtotal							($198)	$46,872
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.							$4	$933
79			Subtotal							$4	$933
80											
81			A&G Expense Sub-total							($194)	$47,806
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$4,826	$4,826	$102,876
84			403.1 Depreciation Expense - ARO/FIN-47								-
85			404.0 Amort. Of Limited-Term Plant						2,109	2,109	18,262
86			Subtotal						$6,935	$6,935	$121,138
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.		$32					$470	$2,072
89			Subtotal		$32					$470	$2,072
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					$114		$114	$9,931
92			Subtotal					$114		$114	$9,931
93											
94			**Total**	**$684**	**$32**	**$4**	**($4,149)**	**$114**	**$6,935**	**($7,759)**	**$579,978**

($ in Thousands)

Line No.	Category	Description	Description	Account	FTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Leap Year Adjustment	D-5D Weather Normalization	D-5E Asset Optimization - Margin Adjustment	D-5F Weather Normal Adjustment	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
					(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	480.0	$380,371	$878	($184)	$423			($14,809)	($13,691)	$366,679
2			C & I	481.0	139,691	490		166			(4,295)	(3,639)	136,053
3			Transportation of Gas of Others	489.3	32,454						(277)	(277)	32,177
4				Subtotal	$552,516	$1,368	($184)	$589			($19,381)	($17,607)	$534,909
5													
6		**Gas Cost Revenue**	Residential	480.0	$216,885								$216,885
7			C & I	481.0	67,023								67,023
8			Interdepartmental	484.0									
9				Subtotal	$283,907								$283,907
10													
11			**Subtotal OPERATING REVENUE**		$836,424	$1,368	($184)	$589			($19,381)	($17,607)	$818,817
12													
13	*OTHER REVENUE*	**Other Gas Revenue**	Rent for Gas Property	493.0	$2,932								$2,932
14			Interdepartmental Rents	494.0									
15			Other Gas Revenues	495.0	818								818
16				Subtotal	$3,750								$3,750
17													
18		**Other Operating Revenue**	Sales For Resale	483.0	$20,000					($20,000)		($20,000)	
19			Forfeited Discounts	487.0	1,328								1,328
20													
21			Miscellaneous Service Revenues	488.0									
22				Subtotal	$21,328					($20,000)		($20,000)	$1,328
23													
24			**Subtotal OTHER REVENUE**		$25,078					($20,000)		($20,000)	$5,078
25													
26				**Total**	**$861,502**	**$1,368**	**($184)**	**$589**		**($20,000)**	**($19,381)**	**($37,607)**	**$823,895**

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Reference	480000: Residential Sales	481001: TCS Sales	481002: GC Sales	481003: L Sales	481005: Other Sales	C & I Total
1	Total FTY Revenues		$597,256	$1,327	$204,009	$253	$961	$206,550
2	Commodity Billings in Revenues		(216,885)	(545)	(65,913)	(95)	(382)	(66,936)
3	Weather Adjustment							
4	Total Reconcilable Surcharge in Revenues		14,587	(0)	(44)	(0)	(1)	(44)
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$394,958	$781	$138,052	$157	$578	$139,570
6								
7	Average Monthly Customers in FTY		512,319	21	44,825	6	16	
8								
9	Average Annual Margin Per Customer	L5 / L7	$0.771	$37.194	$3.080	$26.220	$36.155	
10								
11	Number of Customers of Current Month		513,458	21	44,984	6	16	45,027
12								
13	Increase in Customers During FTY	L11 - L7	1,139		159			45,027
14								
15	Annualization of Revenue	L9 * L13	$878		$490			$490

($ in Thousands)

D-5B - CAP Revenue Credits and Adjustments

Line No.	Description	(1) Reference	(2) Residential Sales
1	CAP Discount		($15,134)
2			
3			
4	**ANNUALIZATION TO YEAR END CUSTOMERS**		
5			
6	Annual CAP Customers		314,428
7	Average Monthly CAP Customers		26,202
8	Average Annual CAP Discount Per Customer	L1 / L7	($0.578)
9			
10	CAP Customers at End ofFTY		26,564
11	Decrease of CAP Customers	L10 - L7	361
12			
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	($209)
14	Write-Offs & Working Capital Factor		11.9%
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	$25
16			
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**($184)**

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Reference	480000: Residential Sales	481001: TCS Sales	481002: GC Sales	481003: L Sales	481005: Other Sales	C & I Total
1	Revenue in February of FTY		$47,382	$108	$18,462	$12	$47	$18,628
2	Days in February of FPFTY		28	28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	1,692	4	659	0	2	
4	Average Days in February		28.25	28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	0.25	
6								
7	**Leap Year Adjustment**	L3 * L5	**$423**	**$1**	**$165**	**$0**	**$0**	**$166**

		(1)
Line No.	Description	Total
1	Residential Sales	
2	TCS Sales	
3	GC Sales	
4	C & I Total	
5	Revenues - Gas Transportation	
6	**Total**	

Line No.	Description	Account	Total
			(1)
1	Other Operating Revenue	483000: Sales for Resale - Gas	($20,000)
2			
3	Purchased Fuel	804000: Natural Gas City Gate Purchases	($15,000)

D-5F - 30-Year vs. 10-Year Weather Normal Adjustment

Line No.	Description	Total (1)
1	Residential Sales	($14,809)
2	TCS Sales	(24)
3	GC Sales	(4,254)
4	Large C&I	(4)
5	Other	(13)
6	Transportation	(277)
7	**Total**	($19,381)

($ in Thousands)

		(1)	(2)	(3)
Line No.	Description	Reference	Union	Non-Union
1	Number of Employees @ HTY - Union/Non-Union		354	341
2	Number of Employees @ HTY - Total		695	695
3	Percentage of Employees @ HTY	L1 / L2	50.92%	49.08%
4	Distribution of Budget S&W Expense		$24,862	$23,966
5				
6	**Annualize March 1 Wage Increase for FTY**			
7	Number of Months TY			2
8	Rate for Increase TY		3.00%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$120
10		L4 + L9	$24,862	$24,086
11				
12	**Annualize January 1 and March 1, 2027 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		2.50%	3.00%
15	Total Adjustment	(L10 * L13 * L14) / 12	$622	$723
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$25,484**	**$24,808**

($ in Thousands)

Line No.	Description	(1) Reference	(2) PECO - Gas
1	Distribution of S&W Expense		$48,828
2			
3	Annualized S&W Including Wage Increases		$50,292
4			
5	**Normalize Contract Payment to Union**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		18.56%
8	Union Contract Payment for Utility	L6 * L7	$242
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$40
11			
12	Annualized S&W for Employees in FPFTY	L3 + L10	$50,332
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ FTY		673
16	Average Number of Employees in FTY - Total		677
17	Annualization for Number of Employees	L15 - L16	(4)
18	Annual S&W per Employee	L12 / L16	$74.4
19	Annualization of S&W for New Employees	L17 * L18	($263)
20			
21	Pro FormaFTY S&W	L12 + L19	$50,069
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$1,241**
24			
25	S&W Pro Forma Factor	L23 / L1	2.54%

($ in Thousands)

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
1	**Operations**	Power Supply Expenses	710.0 Operation Supervision And Engineering.			
2			717.0 Liquefied Petroleum Gas Expenses.	$63	2	$64
3			728.0 Liquefied Petroleum Gas.			
4			804.0 Natural Gas City Gate Purchases.			
5			805.0 Other Gas Purchases.			
6			805.1 Purchased Gas Cost Adjustments.			
7			807.0 Purchased Gas Expenses.			
8			808.1 Gas Withdrawn From Storage-Debit.			
9			808.2 Gas Delivered To Storage-Credit.			
10			813.0 Other Gas Supply Expenses.			
11			840.0 Operation Supervision And Engineering.	229	6	235
12			841.0 Operation Labor And Expenses.	536	14	549
13			843.1 Maintenance Supervision And Engineering.	549	14	563
14			843.2 Maintenance Of Structures And Improvements.	1,832	47	1,878
15			**Subtotal Power Supply Expenses**	$3,208	$82	$3,290
16						
17		Distribution Expense	870.0 Operation Supervision And Engineering.	$9	$0	$9
18			874.0 Mains And Services Expenses.	8,331	212	8,543
19			875.0 Measuring And Regulating Station Expenses--General.	860	22	882
20			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.			
21			878.0 Meter And House Regulator Expenses.	2,068	53	2,120
22			879.0 Customer Installations Expenses.	4,814	122	4,936
23			880.0 Other Expenses.	4,386	111	4,497
24			881.0 Rents.			
25			885.0 Maintenance Supervision And Engineering.			
26			887.0 Maintenance Of Mains.	7,647	194	7,841
27			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	394	10	404
28			892.0 Maintenance Of Services.	1,135	29	1,164
29			893.0 Maintenance Of Meters And House Regulators.	112	3	115
30			894.0 Maintenance Of Other Equipment.	65	2	67
31			**Subtotal Distribution Expense**	$29,821	$758	$30,579
32						
33		Customer Accounts	902.0 Meter Reading Expenses.	$0	$0	$0
34			903.0 Customer Records And Collection Expenses.	6,421	163	6,584
35			904.0 Uncollectible Accounts.			
36			905.0 Miscellaneous Customer Accounts Expenses.	296	8	303
37						
38			**Subtotal Customer Accounts**	$6,717	$171	$6,887
39						
40		Customer Service & Information	908.0 Customer Assistance Expenses	$166	$4	$170

($ in Thousands)

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
41			909.0 Informational And Instructional Advertising Expenses.			
42			910.0 Miscellaneous Customer Service And Informational Expenses.			
43			**Subtotal Customer Service & Information**	$166	$4	$170
44						
45		Sales	912.0 Demonstrating And Selling Expenses.	$323	$8	$331
46			916.0 Miscellaneous Sales Expenses.			
47			**Subtotal Sales**	$323	$8	$331
48						
49		Administration & General - General	920.0 Administrative And General Salaries.	$8,136	$207	$8,343
50			921.0 Office Supplies And Expenses.			
51			922.0 Administrative Expenses Transferred--Credit.			
52			923.0 Outside Services Employed.			
53			924.0 Property Insurance.			
54			925.0 Injuries And Damages.	141	4	145
55			926.0 Employee Pensions And Benefits.			
56			928.0 Regulatory Commission Expenses.			
57			929.0 Duplicate Charges--Credit.			
58			930.2 Miscellaneous General Expenses.	0	0	0
59						
60			**Subtotal Administration & General - General**	$8,277	$210	$8,488
61						
62			**Subtotal Operations**	$48,512	$1,233	$49,745
63						
64	**Maintenance**	Administration & General - General	932.0 Maintenance Of Gas General Plant.	$170	$4	$174
65			**Subtotal Administration & General - General**	$170	$4	$174
66						
67		Gas Expense	741.0 Maintenance Of Structures And Improvements.	$42	$1	$43
68			742.0 Maintenance Of Production Equipment.	104	3	107
69			**Subtotal Gas Expense**	$146	$4	$150
70						
71			**Subtotal Maintenance**	$316	$8	$324
72						
73	**Total Operations & Maintenance**		**Total Operations & Maintenance**	$48,828	$1,241	$50,069
74						
75	**Percent Increase**		**Percent Increase**			2.54%

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$47
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		31
4	**Total Recorded Up To Period End of HTY**	SUM L2 to L3	$78
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$2,782
8	Materials, IT Costs, Travel, Copies, etc.		365
9	**Total Expenditure Expected in FTY**	SUM L7 to L8	$3,148
10			
11	**Total Rate Case Expense**	L4 + L9	$3,226
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,613
15			
16	Annual Amortization Amount Included in Budget		$1,613
17	Pro Forma Adjustment for Annual Amortization	L14 - L16	**$0**

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	**Number of Employees**		
2	Employees at Eleven Months Prior		680
3	Employees at Ten Months Prior		677
4	Employees at Nine Months Prior		674
5	Employees at Eight Months Prior		673
6	Employees at Seven Months Prior		676
7	Employees at Six Months Prior		675
8	Employees at Five Months Prior		674
9	Employees at Four Months Prior		674
10	Employees at Three Months Prior		685
11	Employees at Two Months Prior		681
12	Employees at One Month Prior		677
13	Employees at End of FTY		673
14			
15	Average Monthly Employees in FTY	AVERAGE L2 to L13	677
16	Additional Employees in FTY		(4)
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$7,328
20	Number of Employees for Budget		677
21	Budget Expense Per Employee	L19 / L20	$11
22	Additional Employees for Annualization	L16	(4)
23	Total Benefits Pro Forma Adjustment	L21 * L22	**($38)**

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	Pension Contribution for Four Years Prior to FTY		$15,222
2	Pension Contribution for Three Years Prior to FTY		1,408
3	Pension Contribution for Two Years Prior to FTY		3,690
4	Pension Contribution for One Year Prior to FTY		11,760
5	Pension Contribution for FTY		10,374
6			
7	Average Pension Contribution	AVERAGE L1 to L5	$8,491
8			
9	Allocation Percent to Utility		18.56%
10	Total Amount to Utility	L7 * L9	$1,576
11	Allocation Percent to Capital		42.01%
12	Pension Contribution To Be Capitalized	L10 * L11	$662
13	Pension Contribution To Be Expensed	L10 - L12	$914
14	Budgeted Test Year Distribution Pension Expense		$1,284
15	Additional Pension Expense	L13 - L14	**($370)**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	Reference	Charge Off Amounts	Billed Revenue	Percent	Totals
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$3,091	$778,733	0.3970%	
2		One Year Prior to HTY		2,884	687,070	0.4197%	
3		HTY		6,465	912,486	0.7085%	
4		Three Year Average	SUM L1 to L3 / 3	$4,147	$792,763	0.5231%	
5							
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	FTY			$818,817		
7							
8	Tariff Revenue - Non Shopping Revenue	FTY	L6		$818,817		
9							
10	Tariff Revenue - Shopping Revenue	FTY			$92,745		
11							
12	Tariff Revenue - Including Shopping Revenue	FTY	L8 + L10		$911,562		
13							
14	**Total General Pro Forma Uncollectible Accounts**		Col 4 L4 * L12				$4,768
15							
16	Uncollectible Accounts (904)	FTY					$2,419
17							
18	**Total Pro Forma Adjustment for Uncollectible Accounts**		L14 - L16				$2,349

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Residential Natural Gas Energy Efficiency Program		$423
2	Commercial Natural Gas Energy Efficiency Program		42
3	Sub-total Pro Forma Increase in Gas Energy Efficiency Program Costs	L1 + L2	$464
4	Gas Commercial EE Program Refund - Rate GC		($52)
5	Amortization Years		2
6	Annual Amortization Amount of Gas Commercial EE Program Refund	L4 / L5	($26)
7	Total Gas Energy Efficiency Program Pro Forma Adjustment Amount	L3 + L6	$438

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Description	Reference	Interest Rate	Deposit Amount	Interest on Deposit Amount	Interest Sub Total	Interest Total
1	**Residential**	Monthly Interest Rate		0.583%				
2								
3	January				4,235	25		
4	February				4,342	25		
5	March				4,548	27		
6	April				4,832	28		
7	May				5,032	29		
8	June				5,094	30		
9	July				5,198	30		
10	August				5,305	31		
11	September				5,457	32		
12	October				5,614	33		
13	November				5,723	33		
14	December				5,791	34		
15	**Total Residential**		SUM Col 4 L3 to L14				$357	
16								
17	**Non-Residential**	Monthly Interest Rate		0.292%				
18								
19	January				8,434	25		
20	February				8,568	25		
21	March				8,856	26		
22	April				9,143	27		
23	May				9,347	27		
24	June				9,381	27		
25	July				9,471	28		
26	August				9,539	28		
27	September				9,677	28		
28	October				9,861	29		
29	November				9,900	29		
30	December				10,091	29		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$327	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					$684

		(1)	(2)
Line No.	Description	Reference	Total
1	Regulatory Asset for Unrecovered MGP Remediation Liability		$11,705
2	Amortization Years		8
3			
4	**Total Annual Amortization Amount**	L1/L2	$1,463
5			
6	**Amount Included in Budget**		$1,431
7			
8	**Pro Forma Adjustment Amount**	L4 - L6	**$32**

D-14 Adjustment for MGP Interest

		(1)	(2)
Line No.	Description	Reference	Total
1	Customer Interest on Unspent MGP Collections		($1,316)
2	Amortization Years		2
3	Pro Forma Adjustment Amount	L1 / L2	($658)
4	Annual Amortization Amount Included in Budget		($662)
5	**Pro Forma Adjustment for Annual Amortization**	L3 - L4	**$4**

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Gas Procurement Charge		
2	Rate GR		($1,408)
3	Rate GC		($766)
4	Rate L		($1)
5	Rate OL		
6	Rate MV-F		($13)
7	Total Gas Procurement Charge	SUM L2 to L6	($2,188)
8			
9	Merchant Function Charge / POR		
10	Rate GR		($1,665)
11	Rate GC		($296)
12	Rate L		
13	Rate OL		
14	Rate MV-F		
15	Total Merchant Function Charge / POR	SUM L10 to L14	($1,961)
16			
17	**Total Gas Procurement and Merchant Function Charges**	L7 + L15	**($4,149)**

($ in Thousands)

		(1)	(2)	(3)
Line No.	Description	Total	Pro Forma Adjustments	Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,383		$2,383
2	Capital Stock & Franchise Tax			
3	Use Tax Accrued	817		817
4	Real Estate Tax Accrual	2,129		2,129
5	Miscellaneous TOTI			
6	Payroll Tax Accrued	4,489	$114	4,603
7	**Total**	**$9,817**	**$114**	**$9,931**

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Total Payroll Charged to Expense		$48,828
2	Payroll Tax Expense		$4,489
3	Payroll Tax Expense - Percent	L2 / L1	9.19%
4	Pro Forma Increase in S&W		$1,241
5	**Payroll Tax Pro Forma**	L3 * L4	**$114**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending December 2026
($ in Thousands)
D-17 Depreciation Adjustment

				(1)	(2)	(3)	(4)	(5)
Line No.	Account	Plant Account	Depreciation Category	Depr on Existing Assets + Adds	Depr on Adds	Depr on Existing Assets	Annualize Current Yr Depr	Pro Forma Test Yr Depr
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	$4,635	$112	$4,523	$112	$4,747
2			PECO Common 3902 IL	16		16		16
3			PECO Common 3902 PA	4,473	728	3,745	728	5,201
4			PECO Common 3903 PA	176	43	134	43	219
5			PECO Common 3911 PA	13		13		13
6			PECO Common 3912 PA	2,203	34	2,169	34	2,237
7			PECO Common 3913 IL	3,345	417	2,928	417	3,762
8			PECO Common 3913 PA	10,070	3,002	7,068	3,002	13,072
9			PECO Common 3930 PA	127	7	121	7	134
10			PECO Common 3941 PA	0		0		0
11			PECO Common 3942 PA	68	0	68	0	68
12			PECO Common 3970 PA	6,142	181	5,961	181	6,324
13			PECO Common 3980 PA					
14			Subtotal Common - General Plant	$31,268	$4,524	$26,744	$4,524	$35,792
15								
16		Gas - Distribution	PECO Gas 3751 PA	$278	$22	$256	$22	$300
17			PECO Gas 3752 PA	164	17	147	17	180
18			PECO Gas 3753 PA	118	2	116	2	119
19			PECO Gas 3761 PA	13,825	652	13,173	652	14,476
20			PECO Gas 3762 PA	1,401		1,401		1,401
21			PECO Gas 3763 PA	27,862	1,771	26,091	1,771	29,633
22			PECO Gas 3780 PA	637	30	608	30	667
23			PECO Gas 3790 PA	1,374	68	1,307	68	1,442
24			PECO Gas 3801 PA	3,910	4	3,905	4	3,914
25			PECO Gas 3802 PA	23,090	747	22,342	747	23,837
26			PECO Gas 3810 PA	2,223	39	2,185	39	2,262
27			PECO Gas 3811 PA	3,497	14	3,483	14	3,511
28			PECO Gas 3820 PA	5,270	174	5,096	174	5,444
29			PECO Gas 3870 PA	108		108		108
30			Subtotal Gas - Distribution	$83,757	$3,538	$80,219	$3,538	$87,295
31								

($ in Thousands)

				(1)	(2)	(3)	(4)	(5)
Line No.	Account	Plant Account	Depreciation Category	Depr on Existing Assets + Adds	Depr on Adds	Depr on Existing Assets	Annualize Current Yr Depr	Pro Forma Test Yr Depr
32		Gas - General Plant	PECO Gas 3901 PA	$104	$1	$103	$1	$105
33			PECO Gas 3902 PA	54	0	54	0	54
34			PECO Gas 3903 PA	72	3	69	3	75
35			PECO Gas 3911 PA	0		0		0
36			PECO Gas 3912 PA	44		44		44
37			PECO Gas 3913 IL					
38			PECO Gas 3913 PA	544	9	535	9	553
39			PECO Gas 3940 PA	1,038	24	1,015	24	1,062
40			PECO Gas 3950 PA	2		2		2
41			PECO Gas 3970 PA	340	5	336	5	345
42			PECO Gas 3980 PA	8		8		8
43			Subtotal Gas - General Plant	$2,206	$41	$2,165	$41	$2,247
44								
45		Gas - Production Plant	PECO Gas 3050 PA	$34		$34		$34
46			PECO Gas 3053 PA					
47			PECO Gas 3110 PA	169		169		169
48			Subtotal Gas - Production Plant	$203		$203		$203
49								
50		Gas - Storage	PECO Gas 3611 PA	$40		$40		$40
51			PECO Gas 3612 PA	262	0	261	0	262
52			PECO Gas 3613 PA	18		18		18
53			PECO Gas 3620 PA	8		8		8
54			PECO Gas 3630 PA	19		19		19
55			PECO Gas 3631 PA	128	0	127	0	128
56			PECO Gas 3632 PA	2,678	166	2,511	166	2,844
57			PECO Gas 3633 PA	677	1	677	1	678
58			PECO Gas 3634 PA	482	24	458	24	505
59			PECO Gas 3635 PA	376	14	362	14	390
60			Subtotal Gas - Storage	$4,686	$206	$4,481	$206	$4,892
61								
62			Subtotal 403.0 Depreciation Expense.	$122,120	$8,309	$113,812	$8,309	$130,429
63								

($ in Thousands)

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
64	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 303-CFP B&P SW	$152		$152		$152
65			PECO Com 303-CFP MEU SW	135		135		135
66			PECO Com 303-CFP MMA SW	137		137		137
67			PECO Com 303-DSS Platform Enhanc SW	147		147		147
68			PECO Com 303-EU Custom Hardening SW	277		277		277
69			PECO Com 303-EU EAM SW	599	$331	268	331	930
70			PECO Com 303-EU GIS Core SW	6,981		6,981		6,981
71			PECO Com 303-EU Reliab-Auto SW	139		139		139
72			PECO Com 303-Grid FR Workstream SW	99		99		99
73			PECO Com 303-IGA Enhance Prog SW-C	278		278		278
74			PECO Com 303-LMR SW C	367		367		367
75			PECO Com 303-MO New Bus. Portal SW	170		170		170
76			PECO Com 3030-Apollo SW	5,166	$4,241	925	4,241	9,406
77			PECO Com 3030-BIDA-AMI Ph2 SW	1,001		1,001		1,001
78			PECO Com 3030-Cloud Serv 3 yr	1,751	$31	1,720	31	1,782
79			PECO Com 3030-Cloud Serv 4 yr					
80			PECO Com 3030-Cloud Serv 5 yr	4,755	$323	4,432	323	5,079
81			PECO Com 3030-Common MDM SW	228		228		228
82			PECO Com 3030-EU Digital Program We	2,226		2,226		2,226
83			PECO Com 3030-EU oneMDS SW	5,240		5,240		5,240
84			PECO Com 3030-I Sign Up and Move	385		385		385
85			PECO Com 3030-IT Cust Mobile App SW	95		95		95
86			PECO Com 3030-IVR System PA	234		234		234
87			PECO Com 3030-Misc 5 yr FR PA	9,872	$4,235	5,638	4,235	14,107
88			PECO Com 3030-Mobile Dispatch Mappi	4,138		4,138		4,138
89			Subtotal Common - Intangible Plant	$44,571	$9,161	$35,410	$9,161	$53,732
90								
91			PECO Gas 3913 PA					
92			Subtotal					
93								
94		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	$1,655		$1,655		$1,655
95			PECO Gas 303-CC&B SW	3,353		3,353		3,353
96			PECO Gas 303-PECO RNI Upgrade SW G	108		108		108
97			PECO Gas 303-SES IV G SW	759		759		759
98			PECO Gas 3030-Cloud Serv 5 yr	17		17		17
99			Subtotal Gas - Intangible Plant	$5,893		$5,893		$5,893
100								
101			Subtotal 404.0 Amort. Of Limited-Term Plant	$50,464	$9,161	$41,303	$9,161	$59,624
102								
103			**Grand Total**	**$172,584**	**$17,470**	**$155,114**	**$17,470**	**$190,054**

($ in Thousands)

				(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account	Plant Account	Depreciation Category	Utility Allocation Factor	Depr on Existing Assets + Adds (Utility)	Depr on Adds (Utility)	Depr on Existing Assets (Utility)	Annualize Current Yr Depr (Utility)	Pro Forma Test Yr Depr (Utility)
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	0.2302	$1,067	$26	$1,041	$26	$1,093
2			PECO Common 3902 IL	0.2302	4		4		4
3			PECO Common 3902 PA	0.2302	1,030	168	862	168	1,197
4			PECO Common 3903 PA	0.2302	41	10	31	10	50
5			PECO Common 3911 PA	0.2302	3		3		3
6			PECO Common 3912 PA	0.2302	507	8	499	8	515
7			PECO Common 3913 IL	0.2302	770	96	674	96	866
8			PECO Common 3913 PA	0.2302	2,318	691	1,627	691	3,009
9			PECO Common 3930 PA	0.2302	29	2	28	2	31
10			PECO Common 3941 PA	0.2302	0		0		0
11			PECO Common 3942 PA	0.2302	16	0	16	0	16
12			PECO Common 3970 PA	0.2302	1,414	42	1,372	42	1,456
13			PECO Common 3980 PA	0.2302					
14			Subtotal Common - General Plant		$7,198	$1,041	$6,156	$1,041	$8,239
15									
16		Gas - Distribution	PECO Gas 3751 PA	1.0000	$278	$22	$256	$22	$300
17			PECO Gas 3752 PA	1.0000	164	17	147	17	180
18			PECO Gas 3753 PA	1.0000	118	2	116	2	119
19			PECO Gas 3761 PA	1.0000	13,825	652	13,173	652	14,476
20			PECO Gas 3762 PA	1.0000	1,401		1,401		1,401
21			PECO Gas 3763 PA	1.0000	27,862	1,771	26,091	1,771	29,633
22			PECO Gas 3780 PA	1.0000	637	30	608	30	667
23			PECO Gas 3790 PA	1.0000	1,374	68	1,307	68	1,442
24			PECO Gas 3801 PA	1.0000	3,910	4	3,905	4	3,914
25			PECO Gas 3802 PA	1.0000	23,090	747	22,342	747	23,837
26			PECO Gas 3810 PA	1.0000	2,223	39	2,185	39	2,262
27			PECO Gas 3811 PA	1.0000	3,497	14	3,483	14	3,511
28			PECO Gas 3820 PA	1.0000	5,270	174	5,096	174	5,444
29			PECO Gas 3870 PA	1.0000	108		108		108
30			Subtotal Gas - Distribution		$83,757	$3,538	$80,219	$3,538	$87,295
31									

($ in Thousands)

				(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account	Plant Account	Depreciation Category	Utility Allocation Factor	Depr on Existing Assets + Adds (Utility)	Depr on Adds (Utility)	Depr on Existing Assets (Utility)	Annualize Current Yr Depr (Utility)	Pro Forma Test Yr Depr (Utility)
32		Gas - General Plant	PECO Gas 3901 PA	1.0000	$104	$1	$103	$1	$105
33			PECO Gas 3902 PA	1.0000	54	0	54	0	54
34			PECO Gas 3903 PA	1.0000	72	3	69	3	75
35			PECO Gas 3911 PA	1.0000	0		0		0
36			PECO Gas 3912 PA	1.0000	44		44		44
37			PECO Gas 3913 IL	1.0000					
38			PECO Gas 3913 PA	1.0000	544	9	535	9	553
39			PECO Gas 3940 PA	1.0000	1,038	24	1,015	24	1,062
40			PECO Gas 3950 PA	1.0000	2		2		2
41			PECO Gas 3970 PA	1.0000	340	5	336	5	345
42			PECO Gas 3980 PA	1.0000	8		8		8
43			Subtotal Gas - General Plant		$2,206	$41	$2,165	$41	$2,247
44									
45		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$34		$34		$34
46			PECO Gas 3053 PA	1.0000					
47			PECO Gas 3110 PA	1.0000	169		169		169
48			Subtotal Gas - Production Plant		$203		$203		$203
49									
50		Gas - Storage	PECO Gas 3611 PA	1.0000	$40		$40		$40
51			PECO Gas 3612 PA	1.0000	262	0	261	0	262
52			PECO Gas 3613 PA	1.0000	18		18		18
53			PECO Gas 3620 PA	1.0000	8		8		8
54			PECO Gas 3630 PA	1.0000	19		19		19
55			PECO Gas 3631 PA	1.0000	128	0	127	0	128
56			PECO Gas 3632 PA	1.0000	2,678	166	2,511	166	2,844
57			PECO Gas 3633 PA	1.0000	677	1	677	1	678
58			PECO Gas 3634 PA	1.0000	482	24	458	24	505
59			PECO Gas 3635 PA	1.0000	376	14	362	14	390
60			Subtotal Gas - Storage		$4,686	$206	$4,481	$206	$4,892
61									
62			Subtotal 403.0 Depreciation Expense.		$98,050	$4,826	$93,224	$4,826	$102,876
63									

($ in Thousands)

				(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account	Plant Account	Depreciation Category	Utility Allocation Factor	Depr on Existing Assets + Adds (Utility)	Depr on Adds (Utility)	Depr on Existing Assets (Utility)	Annualize Current Yr Depr (Utility)	Pro Forma Test Yr Depr (Utility)
64	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 303-CFP B&P SW	0.2302	$35		$35		$35
65			PECO Com 303-CFP MEU SW	0.2302	31		31		31
66			PECO Com 303-CFP MMA SW	0.2302	32		32		32
67			PECO Com 303-DSS Platform Enhanc SW	0.2302	34		34		34
68			PECO Com 303-EU Custom Hardening SW	0.2302	64		64		64
69			PECO Com 303-EU EAM SW	0.2302	138	76	62	76	214
70			PECO Com 303-EU GIS Core SW	0.2302	1,607		1,607		1,607
71			PECO Com 303-EU Reliab-Auto SW	0.2302	32		32		32
72			PECO Com 303-Grid FR Workstream SW	0.2302	23		23		23
73			PECO Com 303-IGA Enhance Prog SW-C	0.2302	64		64		64
74			PECO Com 303-LMR SW C	0.2302	85		85		85
75			PECO Com 303-MO New Bus. Portal SW	0.2302	39		39		39
76			PECO Com 3030-Apollo SW	0.2302	1,189	976	213	976	2,165
77			PECO Com 3030-BIDA-AMI Ph2 SW	0.2302	230		230		230
78			PECO Com 3030-Cloud Serv 3 yr	0.2302	403	7	396	7	410
79			PECO Com 3030-Cloud Serv 4 yr	0.2302					
80			PECO Com 3030-Cloud Serv 5 yr	0.2302	1,095	74	1,020	74	1,169
81			PECO Com 3030-Common MDM SW	0.2302	53		53		53
82			PECO Com 3030-EU Digital Program We	0.2302	512		512		512
83			PECO Com 3030-EU oneMDS SW	0.2302	1,206		1,206		1,206
84			PECO Com 3030-I Sign Up and Move	0.2302	89		89		89
85			PECO Com 3030-IT Cust Mobile App SW	0.2302	22		22		22
86			PECO Com 3030-IVR System PA	0.2302	54		54		54
87			PECO Com 3030-Misc 5 yr FR PA	0.2302	2,273	975	1,298	975	3,247
88			PECO Com 3030-Mobile Dispatch Mappi	0.2302	953		953		953
89			Subtotal Common - Intangible Plant		$10,260	$2,109	$8,151	$2,109	$12,369
90									
91			PECO Gas 3913 PA	1.0000					
92			Subtotal						
93									
94		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$1,655		$1,655		$1,655
95			PECO Gas 303-CC&B SW	1.0000	3,353		3,353		3,353
96			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	108		108		108
97			PECO Gas 303-SES IV G SW	1.0000	759		759		759
98			PECO Gas 3030-Cloud Serv 5 yr	1.0000	17		17		17
99			Subtotal Gas - Intangible Plant		$5,893		$5,893		$5,893
100									
101			Subtotal 404.0 Amort. Of Limited-Term Plant		$16,153	$2,109	$14,044	$2,109	$18,262
102									
103			**Grand Total**		**$114,203**	**$6,935**	**$107,268**	**$6,935**	**$121,138**

($ in Thousands)

				(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Account	Plant Account	Depreciation Category	Functional Allocation Factor	Depr on Existing Assets + Adds (Function)	Depr on Adds (Function)	Depr on Existing Assets (Function)	Annualize Current Yr Depr (Function)	Pro Forma FPFTY Depr (Function)
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	1.0000	$1,067	$26	$1,041	$26	$1,093
2			PECO Common 3902 IL	1.0000	4		4		4
3			PECO Common 3902 PA	1.0000	1,030	168	862	168	1,197
4			PECO Common 3903 PA	1.0000	41	10	31	10	50
5			PECO Common 3911 PA	1.0000	3		3		3
6			PECO Common 3912 PA	1.0000	507	8	499	8	515
7			PECO Common 3913 IL	1.0000	770	96	674	96	866
8			PECO Common 3913 PA	1.0000	2,318	691	1,627	691	3,009
9			PECO Common 3930 PA	1.0000	29	2	28	2	31
10			PECO Common 3941 PA	1.0000	0		0		0
11			PECO Common 3942 PA	1.0000	16	0	16	0	16
12			PECO Common 3970 PA	1.0000	1,414	42	1,372	42	1,456
13			PECO Common 3980 PA	1.0000					
14			Subtotal Common - General Plant		$7,198	$1,041	$6,156	$1,041	$8,239
15									
16		Gas - Distribution	PECO Gas 3751 PA	1.0000	$278	$22	$256	$22	$300
17			PECO Gas 3752 PA	1.0000	164	17	147	17	180
18			PECO Gas 3753 PA	1.0000	118	2	116	2	119
19			PECO Gas 3761 PA	1.0000	13,825	652	13,173	652	14,476
20			PECO Gas 3762 PA	1.0000	1,401		1,401		1,401
21			PECO Gas 3763 PA	1.0000	27,862	1,771	26,091	1,771	29,633
22			PECO Gas 3780 PA	1.0000	637	30	608	30	667
23			PECO Gas 3790 PA	1.0000	1,374	68	1,307	68	1,442
24			PECO Gas 3801 PA	1.0000	3,910	4	3,905	4	3,914
25			PECO Gas 3802 PA	1.0000	23,090	747	22,342	747	23,837
26			PECO Gas 3810 PA	1.0000	2,223	39	2,185	39	2,262
27			PECO Gas 3811 PA	1.0000	3,497	14	3,483	14	3,511
28			PECO Gas 3820 PA	1.0000	5,270	174	5,096	174	5,444
29			PECO Gas 3870 PA	1.0000	108		108		108
30			Subtotal Gas - Distribution		$83,757	$3,538	$80,219	$3,538	$87,295
31									

($ in Thousands)

				(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Account	Plant Account	Depreciation Category	Functional Allocation Factor	Depr on Existing Assets + Adds (Function)	Depr on Adds (Function)	Depr on Existing Assets (Function)	Annualize Current Yr Depr (Function)	Pro Forma FPFTY Depr (Function)
32		Gas - General Plant	PECO Gas 3901 PA	1.0000	$104	$1	$103	$1	$105
33			PECO Gas 3902 PA	1.0000	54	0	54	0	54
34			PECO Gas 3903 PA	1.0000	72	3	69	3	75
35			PECO Gas 3911 PA	1.0000	0		0		0
36			PECO Gas 3912 PA	1.0000	44		44		44
37			PECO Gas 3913 IL	1.0000					
38			PECO Gas 3913 PA	1.0000	544	9	535	9	553
39			PECO Gas 3940 PA	1.0000	1,038	24	1,015	24	1,062
40			PECO Gas 3950 PA	1.0000	2		2		2
41			PECO Gas 3970 PA	1.0000	340	5	336	5	345
42			PECO Gas 3980 PA	1.0000	8		8		8
43			Subtotal Gas - General Plant		$2,206	$41	$2,165	$41	$2,247
44									
45		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$34		$34		$34
46			PECO Gas 3053 PA	1.0000					
47			PECO Gas 3110 PA	1.0000	169		169		169
48			Subtotal Gas - Production Plant		$203		$203		$203
49									
50		Gas - Storage	PECO Gas 3611 PA	1.0000	$40		$40		$40
51			PECO Gas 3612 PA	1.0000	262	0	261	0	262
52			PECO Gas 3613 PA	1.0000	18		18		18
53			PECO Gas 3620 PA	1.0000	8		8		8
54			PECO Gas 3630 PA	1.0000	19		19		19
55			PECO Gas 3631 PA	1.0000	128	0	127	0	128
56			PECO Gas 3632 PA	1.0000	2,678	166	2,511	166	2,844
57			PECO Gas 3633 PA	1.0000	677	1	677	1	678
58			PECO Gas 3634 PA	1.0000	482	24	458	24	505
59			PECO Gas 3635 PA	1.0000	376	14	362	14	390
60			Subtotal Gas - Storage		$4,686	$206	$4,481	$206	$4,892
61									
62			Subtotal 403.0 Depreciation Expense.		$98,050	$4,826	$93,224	$4,826	$102,876
63									

($ in Thousands)

				(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Account	Plant Account	Depreciation Category	Functional Allocation Factor	Depr on Existing Assets + Adds (Function)	Depr on Adds (Function)	Depr on Existing Assets (Function)	Annualize Current Yr Depr (Function)	Pro Forma FPFTY Depr (Function)
64	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 303-CFP B&P SW	1.0000	$35		$35		$35
65			PECO Com 303-CFP MEU SW	1.0000	31		31		31
66			PECO Com 303-CFP MMA SW	1.0000	32		32		32
67			PECO Com 303-DSS Platform Enhanc SW	1.0000	34		34		34
68			PECO Com 303-EU Custom Hardening SW	1.0000	64		64		64
69			PECO Com 303-EU EAM SW	1.0000	138	76	62	76	214
70			PECO Com 303-EU GIS Core SW	1.0000	1,607		1,607		1,607
71			PECO Com 303-EU Reliab-Auto SW	1.0000	32		32		32
72			PECO Com 303-Grid FR Workstream SW	1.0000	23		23		23
73			PECO Com 303-IGA Enhance Prog SW-C	1.0000	64		64		64
74			PECO Com 303-LMR SW C	1.0000	85		85		85
75			PECO Com 303-MO New Bus. Portal SW	1.0000	39		39		39
76			PECO Com 3030-Apollo SW	1.0000	1,189	976	213	976	2,165
77			PECO Com 3030-BIDA-AMI Ph2 SW	1.0000	230		230		230
78			PECO Com 3030-Cloud Serv 3 yr	1.0000	403	7	396	7	410
79			PECO Com 3030-Cloud Serv 4 yr	1.0000					
80			PECO Com 3030-Cloud Serv 5 yr	1.0000	1,095	74	1,020	74	1,169
81			PECO Com 3030-Common MDM SW	1.0000	53		53		53
82			PECO Com 3030-EU Digital Program We	1.0000	512		512		512
83			PECO Com 3030-EU oneMDS SW	1.0000	1,206		1,206		1,206
84			PECO Com 3030-I Sign Up and Move	1.0000	89		89		89
85			PECO Com 3030-IT Cust Mobile App SW	1.0000	22		22		22
86			PECO Com 3030-IVR System PA	1.0000	54		54		54
87			PECO Com 3030-Misc 5 yr FR PA	1.0000	2,273	975	1,298	975	3,247
88			PECO Com 3030-Mobile Dispatch Mappi	1.0000	953		953		953
89			Subtotal Common - Intangible Plant		$10,260	$2,109	$8,151	$2,109	$12,369
90									
91			PECO Gas 3913 PA	1.0000					
92			Subtotal						
93									
94		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$1,655		$1,655		$1,655
95			PECO Gas 303-CC&B SW	1.0000	3,353		3,353		3,353
96			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	108		108		108
97			PECO Gas 303-SES IV G SW	1.0000	759		759		759
98			PECO Gas 3030-Cloud Serv 5 yr	1.0000	17		17		17
99			Subtotal Gas - Intangible Plant		$5,893		$5,893		$5,893
100									
101			Subtotal 404.0 Amort. Of Limited-Term Plant		$16,153	$2,109	$14,044	$2,109	$18,262
102									
103			**Grand Total**		**$114,203**	**$6,935**	**$107,268**	**$6,935**	**$121,138**

($ in Thousands)

			(1)	(2)	(3)
Line No.	Description	Reference	Present Rates	Rate Increase	Proposed Rates
1	Revenue		$823,895	$64,925	$888,820
2	Operating Expenses		579,978	631	580,609
3	OIBIT	L1 - L2	$243,917	$64,294	$308,211
4					
5	Rate Base		$3,780,282		$3,780,282
6	Weighted Cost of Debt		2.180%		2.180%
7	Synchronized Interest Expense	L5 * L6	$82,410		$82,410
8	Base Taxable Income	L3 - L7	$161,507	$64,294	$225,801
9					
10	State Accelerated Tax Depreciation		$94,546		$94,546
11	Pro Forma Book Depreciation		121,138		121,138
12	State Tax Depreciation (Over) Under Book	L11 - L10	$26,593		$26,593
13	Regulatory Asset Programs M-1, Pension & Post-Retirement & Other		626		626
14	Other Property Basis Adjustments (CIAC/ICM)		(28,902)		(28,902)
15	Removal Costs/Software		(4,064)		(4,064)
16	AFUDC Equity		-		-
17	Permanent Adjustments		709		709
18	Repair Deduction		(230,000)		(230,000)
19					
20	State Taxable Income	L8 + Sum L12 toL18	($73,530)	$64,294	($9,237)
21					
22	State Income Tax Rate		7.49%	7.49%	7.49%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L20 * L22)	$5,507	($4,816)	$692
24	Net Operating Loss Utilization %		50.00%	50.00%	50.00%
25	Net Operating Loss Utilization	- (L24 * L23)			
26	State Income Tax Benefit / (Expense)	L23 + L25	$5,507	($4,816)	$692
27					
28	Federal Accelerated Tax Depreciation		$91,789		$91,789
29	Pro Forma Book Depreciation		121,138		121,138
30	Federal Tax Deducts (Over) Under Book	L29 - L28	$29,349		$29,349
31	Regulatory Asset Programs M-1, Pension & Post-Retirement		626		626
32	Other Property Basis Adjustments (CIAC/ICM)		(28,902)		(28,902)
33	Removal Costs/Software		(4,064)		(4,064)
34	AFUDC Equity		-		-
35	Permanent Adjustments		709		709
36	Repair Deduction		(230,000)		(230,000)
37	Federal NOL				
38	Federal Taxable Income	L8 - L26 + Sum L30 to L37	($65,267)	$59,478	($5,789)
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	- (L38 * L40)	$13,706	($12,490)	$1,216
42	Corporate Alternative Minimum Tax				
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	$19,213	($17,306)	$1,907
44					

($ in Thousands)

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		($183)		($183)
47	Deferred Taxes on Timing Differences- State		(2,118)		(2,118)
48	Deferred Taxes on State NOL		-	-	-
49	Excess Deferred Amortization		3,188		3,188
50	Excess Deferred Amortization - State (Net of Federal)		271		271
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax on Flow Through Adjustments		(7,717)		(7,717)
53	Corporate Alternative Minimum Tax				
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	($6,559)		($6,559)
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	$12,655	($17,306)	($4,651)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		($3)		($3)
60					
61	Combined Income Tax Benefit / (Expense)	L56 + L59	$12,652	($17,306)	($4,654)
62					
63	Federal Income Tax Benefit / (Expense)	L41 + L46 + L49 + L51 + L52 + L59	$8,991	($12,490)	($3,499)
64	State Income Tax Benefit / (Expense)	L26 + L47+ L48 + L50	$3,661	($4,816)	($1,155)
65	Total Income Tax Benefit / (Expense)	L63 + L64	**$12,652**	**($17,306)**	**($4,654)**

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		1,328
4	Total Customer Revenue		836,424
5	Shopping Revenue		92,745
6	LPC REVENUE	L3 / (L4 + L5)	0.001429
7	GROSS RECEIPTS TAX		
8	UNCOLLECTIBLE EXPENSES		(0.005231)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.004505)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.991693
13			
14	STATE INCOME TAX RATE		7.490%
15			
16	STATE INCOME TAX FACTOR	- L12 * L14	(0.074278)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.917415
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	- L18 * L20	(0.192657)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.724758
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.379771
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	26.694%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		7.490%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.074900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.925100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.194271)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.730829
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.368309
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	26.917%

PECO Exhibit MJT-3:
Principal Accounting Exhibit – HTY 2025

($ in Thousands)

Line No.	Description	Reference (1)	Present Rates (2)	Revenue Increase (3)	Total (4)
1	**MEASURE OF VALUE**				
2	Utility Plant	C-2	$4,649,687		$4,649,687
3	Accumulated Depreciation	C-3	1,031,029		1,031,029
4	Common Plant - Net of Accum Depr	C-8	168,384		168,384
5	Net Plant in service	L2 - L3 + L4	$3,787,042		$3,787,042
6					
7	Working Capital	C-1	$21,063		$21,063
8	Pension Assets / (Liability)	C-1	34,423		34,423
9	Accum Deferred Income Taxes	C-1	(205,045)		(205,045)
10	Customer Deposits	C-1	(14,323)		(14,323)
11	Customer Advances for Construction	C-1	(1,400)		(1,400)
12	Materials and Supplies	C-1	608		608
13	Accum Deferred Income Taxes - Reg Liability	C-1	(109,004)		(109,004)
14	Gas Storage	C-1	32,762		32,762
15					
16	TOTAL RATE BASE	SUM L5 to L14	$3,546,125		$3,546,125
17					
18	**OPERATING REVENUES AND EXPENSES**				
19	Base Customer Charges	D-5	$570,540	$16,110	$586,650
20	Supply Cost Revenue	D-5	287,445		287,445
21	Other Operating Revenues	D-5	6,067	43	6,110
22	Total Revenues	SUM L19 to L21	$864,053	$16,153	$880,205
23					
24	Operating Expenses	D-1	$579,269	$157	$579,426
25					
26	OIBIT	L22 - L24	$284,784	$15,996	$300,779
27					
28	Income Taxes @ Eff Inc Tax Rate	D-18	$4,301		$4,301
29	Income Taxes @ Statutory Rates	D-18		(4,369)	(4,369)
30					
31	NET OPERATING INCOME	SUM L26 to L29	$289,084	$11,627	$300,711
32					
33	RATE OF RETURN	L31 / L16	8.15%		8.48%
34					
35	**REVENUE INCREASE REQUIRED**				
36	Rate of Return at Present Rates	L33	8.15%		
37					
38	Rate of Return Required	B-7	8.48%		
39					
40	Change in ROR	L38 - L36	0.33%		
41					
42	Change in Operating Income	L16 * L40	$11,627		
43					
44	Gross Revenue Conversion Factor	D-19	1.386		
45					
46	Change in Revenues	L42 * L44	$16,110		
47					
48	**RETURN ON COMMON EQUITY**				
49	Common Equity Ratio	B-7	53.50%		
50	Common Equity Rate Base	L16 * L49	$1,897,177		
51	NET OPERATING INCOME	L31	$289,084		
52	Synchronized Interest Expense	D-18	$92,908		
53	NET OPERATING INCOME - COMMON EQUITY	L51 - L52	$196,176		
54	RATE OF RETURN ON COMMON EQUITY	L53 / L50	10.34%		

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	**Utility Plant**		
2	Utility Plant (101-106, 108, 114)		$19,247,007
3	Construction Work In Progress (107)		842,808
4	Total Utility Plant	L2 + L3	$20,089,815
5	Less: Accum. Prov. for Depr. and Amort. (108, 110, 111, 115)		4,153,619
6	Net Utility Plant	L4 - L5	$15,936,196
7			
8	**Other Property and Investments**		
9	Non-Utility Property (121)		$14,745
10	Less: Accum. Prov. for Depr. and Amort. (122)		1,465
11	Invest in Assoc Company (123)		16,388
12	Other Investments (124-129, 175-176)		38,062
13	Total Other Property and Investments	SUM L9 to L12	$67,729
14			
15	**Current and Accrued Assets**		
16	Cash & Other Temporary Investments (131-136)		$107,349
17	Customer Accounts Receivable (142)		533,708
18	Other Accounts Receivable (143)		146,860
19	Accum. Prov. for Uncollectible (144)		(155,196)
20	Receivables from Assoc. Comp. (146)		447
21	Fuel Stock (151)		1,693
22	Plant Materials & Supplies (154)		82,402
23	Allowances and Environmental Credits (158.1, 158.2, 158.3, and 158.4)		336
24	Gas Stored Underground - Current (164.1)		37,749
25	Liquefied Natural Gas stored (164.2)		3,774
26	Prepayments (165)		71,882
27	Accrued Utility Revenues (173)		278,063
28	Miscellaneous Current & Accrued Assets (174)		2,510
29	Total Current and Accrued Assets	SUM L16 to L28	$1,111,575
30			
31	**Deferred Debits**		
32	Unamortized Debt Expense (181)		$54,815
33	Unrecovered Plant and Regulatory Study Costs (182.2)		741
34	Other Regualtory Assets (182.3)		1,346,571
35	Miscellaneous Deferred Debits (186)		901,646
36	Unamortized Loss on Reacquired Debt (189)		
37	Accumulated Deferred Income Taxes (190)		541,926
38	Total Deferred Debits	SUM L32 to L37	$2,845,699
39			
40	**TOTAL ASSETS**	L6+L13+L29+L38	$19,961,199
41			

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Total - PECO
42	**Proprietary Capital**		
43	Common Stock Issued (201)		$1,423,004
44	Preferred Stock Issued (204)		
45	Other Paid-In Capital (208-211)		3,799,345
46	Capital Stock Expense (214)		(87)
47	Retained Earnings (215, 215.2, 216)		5,947,074
48	Unappropriated Undistributed Subsidiary Earnings (216.1)		(3,512,588)
49	Accum Other Comprehensive Income (219)		3,163
50	Total Propriety Capital & Margins	SUM L43 to L49	$7,659,911
51			
52	**Long Term Debt**		
53	Bonds (221)		$6,475,000
54	Advances from Associated Companies (223)		184,419
55	Other Long-Term Debt (224)		
56	Unamortized Premium on LTD (225)		
57	Unamortized Discount on LTD (226)		(24,980)
58	Total Long-Term Debt	SUM L53 to L57	$6,634,438
59			
60	**Other Non-Current Liabilities**		
61	Obligations under Capital Leases (227)		
62	Accum. Prov for Injuries & Damages (228.2)		$62,513
63	Accum. Prov for Pensions & Benefits (228.3)		300,327
64	Accum. Miscellaneous Operating Prov (228.4)		11,729
65	Asset Retirement Obligation (230)		25,838
66	Total Other Non-Current Liabilities	SUM L61 to L65	$400,407
67			
68	**Current and Accrued Liabilities**		
69	Notes Payable (231)		
70	Accounts Payable (232)		$814,817
71	Notes Payable to Assoc. Companies (233)		
72	Accounts Payable to Assoc. Companies (234)		36,173
73	Customer Deposits (235)		93,432
74	Taxes Accrued (236)		311,493
75	Interest Accrued (237)		76,903
76	Dividends Declared (238)		
77	Tax Collections Payable (241)		92
78	Misc Current & Accrued Liabilities (242)		192,665
79	Total Current & Accrued Liabilities	SUM L69 to L78	$1,525,574
80			
81	**Other Deferred Credits**		
82	Customer Advances for Construction (252)		$15,732
83	Other Deferred Credits (253)		1,420
84	Other Regulatory Liabilities (254)		587,580
85	Deferred Investment Tax Credit (255)		286
86	Unamortized Gain on Reacquired Debt (257)		618
87	Accumulated Deferred Income Taxes (281-283)		3,135,233
88	Total Other Deferred Credits	SUM L82 to L87	$3,740,869
89			
90	**TOTAL LIABILITIES AND OTHER CREDITS**	L50+L58+L66+L79+L88	$19,961,199

($ in Thousands)

Line No.	Category	Description	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**Total Operating Revenues**	Customer & Distribution Revenues	$548,545		$548,545
2		Gas Cost Revenue	287,445		287,445
3		Other Operating Revenues	20,999		20,999
4		Total Operating Revenues	$856,989		$856,989
5					
6	**Total Operating Expenses**	Operation & Maintenance Expenses	$469,559		$469,559
7		Depreciation & Amortization Expense	104,499		104,499
8		Amortization of Regulatory Expense	1,459		1,459
9		Taxes Other Than Income Taxes - Other	8,100		8,100
10		Total Operating Expenses	$583,617		$583,617
11					
12	**Net Utility Operating Income Before Income Tax**		$273,372		$273,372

($ in Thousands)

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	HTY Amount	Non-Jurisdictional	Jurisdictional
1	**Operating Revenues**	Customer & Distribution Revenues	Residential	480.0	$373,058		$373,058
2			C & I	481.0	138,219		138,219
3			Transportation of Gas of Others	489.3	37,268		37,268
4				Subtotal	$548,545		$548,545
5							
6		Gas Cost Revenue	Residential	480.0	$219,588		$219,588
7			C & I	481.0	67,857		67,857
8			Interdepartmental	484.0			
9				Subtotal	$287,445		$287,445
10							
11		Other Operating Revenues	Sales For Resale	483.0	$14,675		$14,675
12			Forfeited Discounts	487.0	2,457		2,457
13			Miscellaneous Service Revenues	488.0			
14			Rent for Gas Property	493.0	2,660		2,660
15			Interdepartmental Rents	494.0	257		257
16			Other Gas Revenues	495.0	951		951
17				Subtotal	$20,999		$20,999
18							
19			**Total Operating Revenues**		$856,989		$856,989
20							
21	**Operating Expenses**	Operation & Maintenance Expenses	Manufactured Gas Production	710.0			
22			Liquefied Petroleum Gas Expenses	717.0	162		162
23			Liquefied Petroleum Gas Expenses	728.0	(165)		(165)
24			Maintenance of Structures and Improvements	741.0	167		167
25			Maintenance of Production Equipment	742.0	270		270
26			Natural Gas City Gate Purchases	804.0	298,802		298,802
27			Other Gas Purchases	805.0			
28			Purchases Gas Cost Adjustments	805.1	1,018		1,018
29			Purchased Gas Expenses	807.0			
30			Gas Withdrawn from Storage-Debit	808.1	35,177		35,177
31			Gas Delivered to Storage-Credit	808.2	(41,232)		(41,232)
32			Other Gas Supply Purchases	813.0	3,298		3,298
33			Other Expenses	824.0			
34			Operating Supervision and Engineering	840.0	471		471

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
35			Operation Labor and Expenses	841.0	1,117		1,117
36			Maintenance Supervision and Engineering	843.1	1,163		1,163
37			Maintenance of Structures and Improvements	843.2	4,665		4,665
38			Operation Supervision and Engineering	870.0	975		975
39			Mains and Services Expenses	874.0	22,179		22,179
40			Measuring and Regulating Station Expenses-General	875.0	1,346		1,346
41			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
42			Meter and House Regulator Expenses	878.0	5,805		5,805
43			Customer Installations Expenses	879.0	7,593		7,593
44			Other Expenses	880.0	18,805		18,805
45			Rents	881.0	213		213
46			Maintenance of Mains	887.0	18,454		18,454
47			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	745		745
48			Maintenance of Services	892.0	2,612		2,612
49			Maintenance of Meters & House Regulators	893.0	179		179
50			Maintenance of Other Equipment	894.0	665		665
51			Meter Reading	902.0	38		38
52			Customer Records and Collection	903.0	17,602		17,602
53			Uncollectible Accounts	904.0	6,051		6,051
54			Miscellaneous Customer Accounts	905.0	871		871
55			Customer Assistance	908.0	8,043		8,043
56			Informational & Instructional	909.0	626		626
57			Miscellaneous Customer & Informational	910.0			
58			Demonstrating & Selling	912.0	769		769
59			Miscellaneous Sales	916.0			
60			Administrative and General Salaries	920.0	5,912		5,912
61			Office Supplies and Expenses	921.0	787		787
62			Administrative Expenses Transferred-Credit	922.0			
63			Outside Service Employed	923.0	20,437		20,437
64			Property Insurance	924.0	192		192
65			Franchise Requirements	925.0	10,176		10,176
66			Employee Pensions and Benefits	926.0	7,812		7,812
67			Regulatory Commission Expenses	928.0	3,578		3,578
68			Duplicate Charges-Credit	929.0	(74)		(74)

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
69			Miscellaneous General Expenses	930.2	608		608
70			Maintenance of General Plant	932.0	1,103		1,103
71			Maintenance of Computer Software	935.2	542		542
72			Maintenance of Communication Equipment	935.3	4		4
73				Subtotal	$469,559		$469,559
74							
75			Depreciation & Amortization Expense	403.0	$89,877		$89,877
76				403.1			
77				404.0	14,622		14,622
78				Subtotal	$104,499		$104,499
79							
80			Amortization of Regulatory Expense	407.3	$1,459		$1,459
81				Subtotal	$1,459		$1,459
82							
83			Taxes Other Than Income Taxes - Other	408.1	$8,100		$8,100
84				Subtotal	$8,100		$8,100
85							
86			**Total Operating Expenses**		$583,617		$583,617
87							
88			**Net Utility Operating Income Before Income Tax**		$273,372		273,372

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
1	**OPERATING REVENUE**	**Customer & Distribution Revenue**	Residential	480.0	$373,058		$373,058
2			C & I	481.0	138,219		138,219
3			Transportation of Gas of Others	489.3	37,268		37,268
4				Subtotal	$548,545		$548,545
5							
6		**Gas Cost Revenue**	Residential	480.0	$219,588		$219,588
7			C & I	481.0	67,857		67,857
8			Interdepartmental	484.0			
9				Subtotal	$287,445		$287,445
10							
11			OPERATING REVENUE		$835,990		$835,990
12							
13	**OTHER REVENUE**	**Other Operating Revenue**	Sales For Resale	483.0	$14,675		$14,675
14			Interdepartmental Sales	484.0	257		257
15			Forfeited Discounts	487.0	2,457		2,457
16			Miscellaneous Service Revenues	488.0			
17				Subtotal	$17,389		$17,389
18							
19		**Other Gas Revenue**	Rent for Gas Property	493.0	$2,660		$2,660
20			Interdepartmental Rents	494.0			
21			Other Gas Revenues	495.0	951		951
22				Subtotal	$3,610		$3,610
23							
24			OTHER REVENUE		$20,999		$20,999
25							
26			OTHER OPERATING REVENUES				
27							
28			**TOTAL**		**$856,989**		**$856,989**

($ in Thousands)

					(1)	(2)	(3)
Line No.	Category	Description	Description	Account	HTY Amount	Non-Jurisdictional	Jurisdictional
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	Manufactured Gas Production	Manufactured Gas Production	710.0			
2			Liquefied Petroleum Gas Expenses	717.0	$162		$162
3			Maintenance of Structures and Improvements	741.0	167		167
4			Maintenance of Production Equipment	742.0	270		270
5				SUM L1 to L4	$599		$599
6							
7	**GAS RAW MATERIALS**	Gas Raw Materials	Liquefied Petroleum Gas Expenses	728.0	(165)		(165)
8							
9	**OTHER GAS SUPPLY EXPENSES**	Other Gas Supply	Natural Gas City Gate Purchases	804.0	$298,802		$298,802
10			Other Gas Purchases	805.0			
11			Purchases Gas Cost Adjustments	805.1	1,018		1,018
12			Purchased Gas Expenses	807.0			
13			Gas Withdrawn from Storage-Debit	808.1	35,177		35,177
14			Gas Delivered to Storage-Credit	808.2	(41,232)		(41,232)
15			Other Gas Supply Purchases	813.0	3,298		3,298
16				SUM L9 to L15	$297,063		$297,063
17							
18	**UNDERGROUND STORAGE EXPENSES**	Underground Storage Expenses	Other Expenses	824.0			
19							
20	**STORAGE EXPENSE**	Storage Operations Expense	Operating Supervision and Engineering	840.0	$471		$471
21			Operation Labor and Expenses	841.0	1,117		1,117
22				SUM L20 to L21	$1,588		$1,588
23							
24		Storage Maintenance Expense	Maintenance Supervision and Engineering	843.1	$1,163		$1,163
25			Maintenance of Structures and Improvements	843.2	4,665		4,665
26				SUM L24 to L25	$5,828		$5,828
27							
28			Subtotal STORAGE EXPENSE	L22 + L26	$7,416		$7,416
29							
30	**DISTRIBUTION EXPENSE**	Distribution Operations	Operation Supervision and Engineering	870.0	$975		$975
31			Mains and Services Expenses	874.0	22,179		22,179
32			Measuring and Regulating Station Expenses-General	875.0	1,346		1,346
33			Measuring and Regulating Station Expenses-City Gate	877.0	0		0
34			Meter and House Regulator Expenses	878.0	5,805		5,805
35			Customer Installations Expenses	879.0	7,593		7,593
36			Other Expenses	880.0	18,805		18,805
37			Rents	881.0	213		213
38				SUM L30 to L37	$56,916		$56,916
39							
40		Distribution Maintenance	Maintenance of Mains	887.0	$18,454		$18,454
41			Maintenance of Measuring & Reg. Station Equip.-Genl.	889.0	745		745
42			Maintenance of Services	892.0	2,612		2,612
43			Maintenance of Meters & House Regulators	893.0	179		179

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) HTY Amount	(2) Non-Jurisdictional	(3) Jurisdictional
44			Maintenance of Other Equipment	894.0	665		665
45				SUM L40 to L44	$22,655		$22,655
46							
47			Subtotal DISTRIBUTION EXPENSE	L38 + L45	$79,570		$79,570
48							
49	**CUSTOMER ACCOUNTS**	Customer Accounts	Meter Reading	902.0	$38		$38
50			Customer Records and Collection	903.0	17,602		17,602
51			Uncollectible Accounts	904.0	6,051		6,051
52			Miscellaneous Customer Accounts	905.0	871		871
53			Subtotal CUSTOMER ACCOUNTS	SUM L49 to L52	$24,562		$24,562
54							
55	**CUSTOMER SERVICE & INFORMATION**	Customer Service & Information	Customer Assistance	908.0	$8,043		$8,043
56			Informational & Instructional	909.0	626		626
57			Miscellaneous Customer & Informational	910.0			
58			Subtotal CUSTOMER SERVICE & INFORMATION	SUM L55 to L57	$8,669		$8,669
59							
60	**SALES**	Sales	Demonstrating & Selling	912.0	$769		$769
61			Miscellaneous Sales	916.0			
62			Subtotal SALES	SUM L60 to L61	$769		$769
63							
64	**ADMINISTRATION & GENERAL**	A&G Operations	Administrative and General Salaries	920.0	$5,912		$5,912
65			Office Supplies and Expenses	921.0	787		787
66			Administrative Expenses Transferred-Credit	922.0			
67			Outside Service Employed	923.0	20,437		20,437
68			Property Insurance	924.0	192		192
69			Injuries & Damages	925.0	10,176		10,176
70			Employee Pensions and Benefits	926.0	7,812		7,812
71			Regulatory Commission Expenses	928.0	3,578		3,578
72			Duplicate Charges-Credit	929.0	(74)		(74)
73			Miscellaneous General Expenses	930.2	608		608
74				SUM L64 to L73	$49,427		$49,427
75							
76		A&G Maintenance	Maintenance of General Plant	932.0	$1,103		$1,103
77			Maintenance of Computer Software	935.2	542		542
78			Maintenance of Communication Equipment	935.3	4		4
79			Subtotal ADMINISTRATION & GENERAL	L74 + L76	$51,076		$51,076
80							
81			**Total**	.ines 5+10+16+28+47+53+58+62+79	$469,559		$469,559
82							
83			Total Operations Expense		$438,991		$439,428
84			Total Maintenance Expense		30,568		30,127
85			**Total O&M Expense**	L83 + L84	$469,559		$469,555

($ in Thousands)

		(1)	(2)
Line No.	Description	Total	Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,577	$2,577
2	Capital Stock & Franchise Tax	37	37
3	Use Tax Accrued	10	10
4	Real Estate Tax Accrual	1,677	1,677
5	Miscellaneous TOTI	15	15
6	Payroll Tax Accrued	3,784	3,947
7	**Total**	$8,100	$8,263

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
B-6 Cost of Long Term Debt

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Type of Bond Issue	Bond Issue	Reference	Amount Outstanding	Percent to Total	Effective Interest Rate	Average Weighted Cost Rate	Annualized Cost
1	**First & Refunding Mortgage Bonds - Fixed Rate**	PECO - FMB - $575 - 4.90% - Due 6-15-2033		$575,000		5.03%		
2					8.63%		0.43%	
3		PECO - FMB - $75 - 5.90% - Due 5-1-2034		75,000		6.00%		
4					1.13%		0.07%	
5		PECO - FMB - $525 -4.875% - Due 9-15-2035		525,000		5.00%		
6					7.88%		0.39%	
7		PECO - FMB - $300 - 5.95% - Due 10-1-2036		300,000		6.04%		
8					4.50%		0.27%	
9		PECO - FMB - $175 - 5.70% - Due 3-15-2037		175,000		5.81%		
10					2.63%		0.15%	
11		PECO - FMB - $250 - 4.80% - Due 10-15-2043		250,000		4.89%		
12					3.75%		0.18%	
13		PECO - FMB - $300 - 4.15% - Due 10-1-2044		300,000		4.23%		
14					4.50%		0.19%	
15		PECO - FMB - $325 - 3.70% - Due 9-15-2047		325,000		3.77%		
16					4.88%		0.18%	
17		PECO - FMB - $325 - 3.90% - Due 3-1-2048		325,000		3.99%		
18					4.88%		0.19%	
19		PECO - FMB - $325 - 3.90% - Due 9-15-2048		325,000		4.17%		
20					4.88%		0.20%	
21		PECO - FMB - $325 - 3.00% - Due 9-15-2049		325,000		3.10%		
22					4.88%		0.15%	
23		PECO - FMB - $350 - 2.80% - Due 6-15-2050		350,000		2.86%		
24					5.26%		0.15%	
25		PECO - FMB - $375 - 3.05% - Due 3-1-2051		375,000		3.11%		
26					5.63%		0.18%	
27		PECO - FMB - $375 - 2.85% - Due 9-15-2051		375,000		2.91%		
28					5.63%		0.16%	
29		PECO - FMB - $350 - 4.60% - Due 6-1-2052		350,000		4.71%		
30					5.26%		0.25%	
31		PECO - FMB - $425 - 4.375% - Due 9-1-2052		425,000		4.46%		
32					6.38%		0.28%	
33		PECO - FMB - $575 - 5.25% - Due 9-15-54		575,000		5.34%		
34					8.63%		0.46%	
35		PECO - FMB - $525 - 5.65% - Due 9-15-55		525,000		5.72%		
36					7.88%		0.45%	
37								
38		Sub-Total Mortgage Bonds	SUM L1 to L36	$6,475,000	97.23%		4.33%	
39								
40	**Trust Preferred Capital Securities**	PECO - TOPRS - $80.5 - 7.38% - Due 4-6-2028		$80,521		7.50%		
41					1.21%		0.09%	
42		PECO - TOPRS - $0.8 - Var (8.75%) - Due 4-6-2028		805		8.75%		
43					0.01%			
44		PECO - TOPRS - $103 - 5.75% - Due 6-15-2033		103,093		5.88%		
45					1.55%		0.09%	
46								
47		Sub-Total Capital Securities	SUM L40 to L45	$184,419	2.77%		0.18%	
48								
49		Total Long-Term Debt	L38 + L47	$6,659,419	100.00%		4.51%	
50								
51		Adjustments for Tenders & Calls		(521)				
52								
53		Net Long-Term Debt	L49 + L51	$6,658,898				
54								
55		Annualized Cost		300,340				
56								
57		Adjustment for Tenders & Calls Reacquired		68				
58								
59		**Total**	L55 + L57	$375,340				5.64%

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Capitalization	Capitalization Ratio	Embedded Cost	Return %
1					
2	Long-Term Debt	$6,658,898	46.50%	5.64%	2.62%
3					
4	Common Equity	7,659,911	53.50%	10.95%	5.86%
5					
6	Total	$14,318,809	100.00%		8.48%

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	HTY Amount	Non-Jurisdictional	Jurisdictional
1	Utility Plant	C-2	$4,649,687		$4,649,687
2	Accumulated Depreciation	C-3	1,031,029		1,031,029
3	Common Plant	C-8	168,384		168,384
4	**Net Plant in Service**	L1 - L2 + L3	$3,787,042		$3,787,042
5					
6	Working Capital	C-4	$21,063		$21,063
7	Pension Assets / (Liability)	C-5	34,423		34,423
8	Accumulated Deferred Income Taxes	C-6	(205,045)		(205,045)
9	Customer Deposits	C-7	(14,323)		(14,323)
10	Customer Advances for Construction	C-9	(1,400)		(1,400)
11	Material & Supplies	C-11	608		608
12	ADIT - Reg Liability	C-12	(109,004)		(109,004)
13	Gas Storage	C-13	32,762		32,762
14	**Total Measures of Value**	SUM L4 to L13	$3,546,125		$3,546,125

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	HTY Amount	Non-Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents		$50		$50
2		G303 - Intangible Property		50,570		50,570
3		Subtotal	SUM L1 to L2	$50,620		$50,620
4						
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements		$1,225		$1,225
6		G311 - Liquefied Petroleum Gas Equip.		14,452		14,452
7		Subtotal	SUM L5 to L6	$15,677		$15,677
8						
9	**Other Storage Plant**	G360 - Land and Land Rights		$16		$16
10		G361 - Structures & Improvements		15,193		15,193
11		G362 - Gas Holders		7,084		7,084
12		G363 - Gas Storage Equipment		109,180		109,180
13		Subtotal	SUM L9 to L12	$131,472		$131,472
14						
15	**Distribution Plant**	G374 - Land and Land Rights		$5,809		$5,809
16		G375 - Structures and Improvements		27,473		27,473
17		G376 - Gas Mains		2,436,767		2,436,767
18		G378 - Measure & Regulate Sta Equip		32,354		32,354
19		G379 - City Gate Station		82,239		82,239
20		G380 - Services		1,355,291		1,355,291
21		G381 - Meters		178,949		178,949
22		G382 - Meter Installations		288,570		288,570
23		G387 - Other Equipment		2,681		2,681
24		G388 - ARO Costs Distribution Plt		(244)	-	(244)
25		Subtotal	SUM L15 to L24	$4,409,890		$4,409,890
26						
27	**General Plant**	G390 - Structures & Improvements		$10,683		$10,683
28		G391 - Office Furniture & Equipment		3,785		3,785
29		G394 - Tools, Shop & Garage Equip		20,999		20,999
30		G395 - Laboratory Equipment		38		38
31		G397 - Communication Equipment		6,352		6,352
32		G398 - Miscellaneous Equipment		127		127
33		G399.1 - ARO Costs General Plt		45		45
34		Subtotal	SUM L27 to L33	$42,028		$42,028
35						
36		**Total**	Lines 3+7+13+25+34	$4,649,687		$4,649,687

($ in Thousands)

Line No.	Category	Account	Additions to Plant
			(1)
1	**Intangible Plant**	G303 - Intangible Property	
2		Subtotal Intangible Plant	
3			
4	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	
12		Subtotal Other Storage Plant	
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	
16		G376 - Gas Mains	
17		G378 - Measure & Regulate Station Equipment	
18		G379 - City Gate Station	
19		G380 - Services	
20		G381 - Meters	
21		G382 - Meter Installations	
22		G387 - Other Equipment	
23		Subtotal Distribution Plant	
24			
25	**General Plant**	G390 - Structures & Improvements	
26		G391 - Office Furniture & Equipment	
27		G394 - Tools, Shop & Garage Equipment	
28		G395 - Laboratory Equipment	
29		G397 - Communication Equipment	
30		G398 - Miscellaneous Equipment	
31		Subtotal General Plant	
32			
33		Total	

($ in Thousands)

Line No.	Category	Account	(1) Plant Retirements
1	**Intangible Plant**	G303 - Intangible Property	
2		Subtotal Intangible Plant	
3			
4	**Manufactured Gas Proc**	G305 - Structures and Improvements	
5		G311 - Liquefied Petroleum Gas Equipment	
6		Subtotal Manufactured Gas Production Plant	
7			
8	**Other Storage Plant**	G360 - Land and Land Rights	
9		G361 - Structures & Improvements	
10		G362 - Gas Holders	
11		G363 - Gas Storage Equipment	
12		Subtotal Other Storage Plant	
13			
14	**Distribution Plant**	G374 - Land and Land Rights	
15		G375 - Structures and Improvements	
16		G376 - Gas Mains	
17		G378 - Measure & Regulate Station Equipment	
18		G379 - City Gate Station	
19		G380 - Services	
20		G381 - Meters	
21		G382 - Meter Installations	
22		G387 - Other Equipment	
23		G388 - ARO Costs Distribution Plant	
24		Subtotal Distribution Plant	
25			
26	**General Plant**	G390 - Structures & Improvements	
27		G391 - Office Furniture & Equipment	
28		G394 - Tools, Shop & Garage Equipment	
29		G397 - Communication Equipment	
30		G398 - Miscellaneous Equipment	
31		G399.1 - ARO Costs General Plant	
32		Subtotal General Plant	
33			
34		Total	

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
C-2 Plant Pro Forma Adjustments

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	HTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	G302 - Franchises & Consents	$50	100.00%	$50	100.00%	$50	
2			$50		$50		$50	
3								
4		G303 - Intangible Property	$50,570	100.00%	$50,570	100.00%	$50,570	
5			$50,570		$50,570		$50,570	
6								
7		Subtotal	**$50,620**		**$50,620**		**$50,620**	
8								
9	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$1,225	100.00%	$1,225	100.00%	$1,225	
10			$1,225		$1,225		$1,225	
11								
12		G311 - Liquefied Petroleum Gas Equip	$14,452	100.00%	$14,452	100.00%	$14,452	
13			$14,452		$14,452		$14,452	
14								
15		Subtotal	**$15,677**		**$15,677**		**$15,677**	
16								
17	**Other Storage Plant**	G360 - Land and Land Rights	$16	100.00%	$16	100.00%	$16	
18			$16		$16		$16	
19								
20		G361 - Structures & Improvements	$15,193	100.00%	$15,193	100.00%	$15,193	
21			$15,193		$15,193		$15,193	
22								
23		G362 - Gas Holders	$7,084	100.00%	$7,084	100.00%	$7,084	
24			$7,084		$7,084		$7,084	
25								
26		G363 - Gas Storage Equipment	$109,180	100.00%	$109,180	100.00%	$109,180	
27			$109,180		$109,180		$109,180	
28								
29		Subtotal	**$131,472**		**$131,472**		**$131,472**	
30								
31	**Distribution Plant**	G374 - Land and Land Rights	$5,809	100.00%	$5,809	100.00%	$5,809	
32			$5,809		$5,809		$5,809	
33								
34		G375 - Structures and Improvements	$27,473	100.00%	$27,473	100.00%	$27,473	
35			$27,473		$27,473		$27,473	
36								
37		G376 - Gas Mains	$2,436,767	100.00%	$2,436,767	100.00%	$2,436,767	
38			$2,436,767		$2,436,767		$2,436,767	
39								
40		G378 - Measure & Regulate Sta Equip	$32,354	100.00%	$32,354	100.00%	$32,354	
41			$32,354		$32,354		$32,354	
42								
43		G379 - City Gate Station	$82,239	100.00%	$82,239	100.00%	$82,239	
44			$82,239		$82,239		$82,239	
45								
46		G380 - Services	$1,355,291	100.00%	$1,355,291	100.00%	$1,355,291	
47			$1,355,291		$1,355,291		$1,355,291	
48								
49		G381 - Meters	$178,949	100.00%	$178,949	100.00%	$178,949	
50			$178,949		$178,949		$178,949	
51								
52		G382 - Meter Installations	$288,570	100.00%	$288,570	100.00%	$288,570	
53			$288,570		$288,570		$288,570	
54								
55		G387 - Other Equipment	$2,681	100.00%	$2,681	100.00%	$2,681	
56			$2,681		$2,681		$2,681	
57								

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Account	HTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
58		G388 - ARO Costs Distribution Plant	($244)	100.00%	($244)	100.00%	($244)	
59			($244)		($244)		($244)	
60								
61		Subtotal	**$4,409,890**		**$4,409,890**		**$4,409,890**	
62								
63	**General Plant**	G390 - Structures & Improvements	$10,683	100.00%	$10,683	100.00%	$10,683	
64			$10,683		$10,683		$10,683	
65								
66		G391 - Office Furniture & Equipment	$3,785	100.00%	$3,785	100.00%	$3,785	
67			$3,785		$3,785		$3,785	
68								
69		G394 - Tools, Shop & Garage Equip	$20,999	100.00%	$20,999	100.00%	$20,999	
70			$20,999		$20,999		$20,999	
71								
72		G395 - Laboratory Equipment	$38	100.00%	38	100.00%	38	
73			38		38		38	
74								
75		G397 - Communication Equipment	$6,352	100.00%	$6,352	100.00%	$6,352	
76			$6,352		$6,352		$6,352	
77								
78		G398 - Miscellaneous Equipment	$127	100.00%	$127	100.00%	$127	
79			$127		$127		$127	
80								
81		G399.1 - ARO Costs General Plant	$45	100.00%	$45	100.00%	$45	
82			$45		$45		$45	
83								
84		Subtotal	**$42,028**		**$42,028**		**$42,028**	
85								
86								
87		**Total**	**$4,649,687**		**$4,649,687**		**$4,649,687**	

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Category	Account	Reference	HTY Amount	Non- Jurisdictional	Jurisdictional
1	**Intangible Plant**	G302 - Franchises & Consents				
2		G303 - Intangible Property		$17,286		$17,286
3		Subtotal Intangible Plant	SUM L1 to L2	$17,286		$17,286
4						
5	**Manufactured Gas Production Plant**	G305 - Structures and Improvements		$937		$937
6		G311 - Liquefied Petroleum Gas Equipment		13,016		13,016
7		Subtotal Manufactured Gas Production Plant	SUM L5 to L6	$13,952		$13,952
8						
9	**Other Storage Plant**	G360 - Land and Land Rights				
10		G361 - Structures & Improvements		$8,342		$8,342
11		G362 - Gas Holders		6,917		6,917
12		G363 - Gas Storage Equipment		19,861		19,861
13		Subtotal Other Storage Plant	SUM L9 to L12	$35,120		$35,120
14						
15	**Distribution Plant**	G374 - Land and Land Rights				
16		G375 - Structures and Improvements		$6,880		6,880
17		G376 - Gas Mains		$419,874		419,874
18		G378 - Measure & Regulate Station Equipment		$6,690		6,690
19		G379 - City Gate Station		$27,822		27,822
20		G380 - Services		$318,539		318,539
21		G381 - Meters		$89,232		89,232
22		G382 - Meter Installations		$75,857		75,857
23		G387 - Other Equipment		$1,645		1,645
24		G388 - ARO Costs Distribution Plant		$629		629
25		Subtotal Distribution Plant	SUM L15 to L24	$947,167		$947,167
26						
27	**General Plant**	G390 - Structures & Improvements		$3,805		$3,805
28		G391 - Office Furniture & Equipment		$1,054		1,054
29		G394 - Tools, Shop & Garage Equipment		$7,504		7,504
30		G395 - Laboratory Equipment		$18		18
31		G397 - Communication Equipment		$5,000		5,000
32		G398 - Miscellaneous Equipment		$76		76
33		G399.1 - ARO Costs General Plant		$48		48
34		Subtotal General Plant	SUM L27 to L33	$17,504		$17,504
35						
36		**Total**	Lines 3+7+13+25+34	$1,031,029		$1,031,029

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Category	Account	HTY Amount	Utility Allocation Factor	Allocated to Utility	Jurisdictional Allocation Factor	Allocated to Jurisdiction	Allocated to Non Jurisdiction
1	**Intangible Plant**	G302 - Franchises & Consents						
2								
3		G303 - Intangible Property	$17,286	100.00%	$17,286	100.00%	$17,286	
4								
5		Subtotal	$17,286		$17,286		$17,286	
6								
7	**Distribution Plant**	G374 - Land and Land Rights		100.00%		100.00%		
8								
9		G375 - Structures and Improvements	6,880	100.00%	6,880	100.00%	6,880	
10								
11		G376 - Gas Mains	419,874	100.00%	419,874	100.00%	419,874	
12								
13		G378 - Measure & Regulate Sta Equip	6,690	100.00%	6,690	100.00%	6,690	
14								
15		G379 - City Gate Station	27,822	100.00%	27,822	100.00%	27,822	
16								
17		G380 - Services	318,539	100.00%	318,539	100.00%	318,539	
18								
19		G381 - Meters	89,232	100.00%	89,232	100.00%	89,232	
20								
21		G382 - Meter Installations	75,857	100.00%	75,857	100.00%	75,857	
22								
23		G387 - Other Equipment	1,645	100.00%	1,645	100.00%	1,645	
24								
25		G388 - ARO Costs Distribution Plant	629	100.00%	629	100.00%	629	
26								
27		Subtotal	**$947,167**		**$947,167**		**$947,167**	
28								
29	**General Plant**	G390 - Structures & Improvements	$3,805	100.00%	$3,805	100.00%	$3,805	
30								
31		G391 - Office Furniture & Equipment	1,054	100.00%	1,054	100.00%	1,054	
32								
33		G394 - Tools, Shop & Garage Equip	7,504	100.00%	7,504	100.00%	7,504	
34								
35		G395 - Laboratory Equipment	18	100.00%	18	100.00%	18	
36								
37		G397 - Communication Equipment	5,000	100.00%	5,000	100.00%	5,000	
38								
39		G398 - Miscellaneous Equipment	76	100.00%	76	100.00%	76	
40								
41		G399.1 - ARO Costs General Plant	48	100.00%	48	100.00%	48	
42								
43		Subtotal	**$17,504**		**$17,504**		**$17,504**	
44								
45	**Manufactured Gas Production Plant**	G305 - Structures and Improvements	$937	100.00%	$937	100.00%	$937	
46								
47		G311 - Liquefied Petroleum Gas Eqp	13,016	100.00%	13,016	100.00%	13,016	
48								
49		Subtotal	**$13,952**		**$13,952**		**$13,952**	
50								
51	**Other Storage Plant**	G360 - Land and Land Rights						
52								
53		G361 - Structures & Improvements	$8,342	100.00%	$8,342	100.00%	$8,342	
54								
55		G362 - Gas Holders	6,917	100.00%	6,917	100.00%	6,917	
56								
57		G363 - Gas Storage Equipment	19,861	100.00%	19,861	100.00%	19,861	
58								
59		Subtotal	**$35,120**		**$35,120**		**$35,120**	
60								
61		**Total**	**$1,031,029**		**$1,031,029**		**$1,031,029**	

($ in Thousands)

Line No.	Category	Account	Reference (1)	HTY Amount (2)
1	**Gas - Production Plant**	G305 - Structures and Improvements		
2		G311 - Liquefied Petroleum Gas Equipment		
3		Subtotal Gas - Production Plant	SUM L1 to L2	
4				
5	**Gas - Storage**	G361 - Structures & Improvements		
6		G363 - Gas Storage Equipment		
7		Subtotal Gas - Storage	SUM L5 to L6	
8				
9	**Gas - Distribution**	G374 - Land and Land Rights		
10		G375 - Structures and Improvements		
11		G376 - Gas Mains		
12		G378 - Measure & Regulate Station Equipment		
13		G379 - City Gate Station		
14		G380 - Services		
15		G381 - Meters		
16		G382 - Meter Installations		
17		G387 - Other Equipment		
18		Subtotal Gas - Distribution	SUM L9 to L17	
19				
20	**Gas - General Plant**	G390 - Structures & Improvements		
21		G391 - Office Furniture & Equipment		
22		G394 - Tools, Shop & Garage Equipment		
23		G397 - Communication Equipment		
24		Subtotal Gas - General Plant	SUM L20 to L23	
25				
26		**Total**	Lines 3+7+18+24	

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	HTY Expenses	(Lead)/Lag Days	Dollar-Days
1	**Working Capital Requirement**				
2					
3	Revenue Lag Days			53.53	
4					
5	Expense Lag				
6	Payroll (Dist Only)		$51,670	13.56	$700,776
7	Pension Expense		1,062	(167.00)	(177,389)
8	Commodity Purchased - Gas		288,414	30.55	8,809,673
9	Payment to Suppliers		89,762	56.21	5,045,394
10	Other Expenses		113,441	43.21	4,901,374
11	Total O&M and POR Payments	SUM L6 to L10	$544,349		$19,279,827
12					
13	O&M Expense / POR Payment Lag Days			35.42	
14					
15	Net (Lead)/Lag Days	L3 - L13		18.11	
16					
17	Days in Current Year			365	
18					
19	Operating Expenses Per Day		$1,491		
20					
21	Working Capital for O&M Expense		$27,012		
22					
23	Average Prepayments		$2,593		
24	Accrued Taxes		1,069		
25	Interest Payments		(9,611)		
26					
27	Total Working Capital Requirement	SUM L21 to L25	$21,063		
28					
29	Pro Forma O&M Expense		$457,583		
30	Uncollectible Expense		2,996		
31	Pro Forma Cash O&M Expense	L29 - L30	$454,587		

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	Accounts Receivable Balance End of Month	Total Monthly Billing Revenue	A/R Turnover	Days Lag
1	Annual Number of Days					365
2						
3	December		$84,688			
4	January		133,726	$147,748		
5	February		145,270	147,778		
6	March		140,858	129,848		
7	April		118,807	81,256		
8	May		90,609	47,245		
9	June		83,001	38,897		
10	July		66,268	29,357		
11	August		56,882	28,650		
12	September		51,634	31,790		
13	October		49,213	37,052		
14	November		76,323	62,417		
15	December		115,675	130,449		
16						
17	Total	SUM L3 to L15	$1,212,954	$912,486		
18						
19	Average A/R Balance		13			
20						
21	Factor		$93,304	$912,486	9.78	37.32
22						
23	Collection Days Lag					37.32
24						
25	Billing and Revenue Recording Days Lag					1.00
26						
27	Billing Lag (Average Period)	365 / 12. * 0.5				15.21
28						
29	Total Revenue Lag Days	L23 + L25 + L27				**53.53**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Category	Description	Reference	Payment Date	Mid-point of Service Period	Expense Amount	(Lead)/Lag Days	Dollar Days
1	PAYROLL	Union & Non-Union Payroll				$49,536		
2		Paid Twice Per Month					13.56	
3		Weighted Payroll Dollar Value						$671,832
4								
5		Payroll Lag	SUM L1 to L3			49,536	13.56	$671,832
6								
7	PENSION PAYMENTS	First Payment						
8		Second Payment						
9		Third Payment						
10		Fourth Payment						
11		Final Payment		1/15/2025	7/1/2025	$11,760	$ (167.00)	($1,963,934)
12								
13		Sub-Total	SUM L7 to L11			$11,760		($1,963,934)
14								
15		Lag Days for Pension Payment					$ (167.00)	
16								
17	PURCHASE COMMODITY COSTS	Payment Lag - Payment to Suppliers					56.21	
18								
19	OTHER O & M EXPENSES	March				$15,875		$656,144
20		June				18,479		697,875
21		September				36,511		1,651,476
22		December				35,501		1,590,220
23								
24		TOTAL	SUM L19 to L22			$106,366	43.21	$4,595,716

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Months	Description	Number of CDs	Cash Disbursements	Dollar-Days	Expense Lag Days
1	March	Total Disbursements for Month	33,074	$278,546		
2		Total Disbursements for Expenses	1,922	$15,875	$656,144	41.33
3						
4	June	Total Disbursements for Month	31,793	$240,494		
5		Total Disbursements for Expenses	1,904	$18,479	$697,875	37.77
6						
7	September	Total Disbursements for Month	38,855	$305,643		
8		Total Disbursements for Expenses	1,853	$36,511	$1,651,476	45.23
9						
10	December	Total Disbursements for Month	32,848	$369,705		
11		Total Disbursements for Expenses	2,215	$35,501	$1,590,220	44.79
12	**TOTAL FOUR TEST MONTHS**					
13						
14	Total Test Month Expense Disbursement		7,894	$106,366	$4,595,716	43.21

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Tax	Description	Payment Date	Mid Point Date	Lead/(Lag) Payment Days	Total Payment Amount	Payment Percentage	Payment Amount	Weighted Dollar Days
1	**FEDERAL INCOME TAX**	First Payment	4/15/2025	7/1/2025	77	($1,973)	25.00%	($493)	($37,977)
2		Second Payment	6/16/2025	7/1/2025	15	($1,973)	25.00%	(493)	(7,398)
3		Third Payment	9/15/2025	7/1/2025	(76)	($1,973)	25.00%	(493)	37,483
4		Fourth Payment	12/15/2025	7/1/2025	(167)	($1,973)	25.00%	(493)	82,365
5		Subtotal FEDERAL INCOME TAX					100.00%	($1,973)	$74,474
6									
7	**STATE INCOME TAX**	First Payment	3/17/2025	7/1/2025	106	($538)	25.00%	($135)	($14,265)
8		Second Payment	6/16/2025	7/1/2025	15	($538)	25.00%	(135)	(2,019)
9		Third Payment	9/15/2025	7/1/2025	(76)	($538)	25.00%	(135)	10,228
10		Fourth Payment	12/15/2025	7/1/2025	(167)	($538)	25.00%	(135)	22,474
11		Subtotal STATE INCOME TAX					100.00%	($538)	$16,418
12									
13	**PURTA**	First Payment	5/1/2025	7/1/2025	61	$2,577	100.00%	$2,577	$157,191
14		Subtotal PURTA					100.00%	$2,577	$157,191
15									
16	**PA CAPITAL STOCK TAX**	First Payment							
17		Second Payment							
18		Third Payment							
19		Fourth Payment							
20		Subtotal PA CAPITAL STOCK TAX							
21									
22	**PA PROPERTY TAX**	First Payment	6/2/2025	7/1/2025	29	$1,677	100.00%	1,677	48,643
23		Second Payment							
24		Subtotal PA PROPERTY TAX					100.00%	1,677	48,643
25									
26	**GROSS RECEIPTS TAX**	First Payment							
27		Subtotal GROSS RECEIPTS TAX							

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Total Payment Amount	Weighted Dollar Days	Payment Lead/(Lag) Days	Revenue Lag Days	Net Payment Lead/(Lag) Days	Net Payment Lead/(Lag) Dollars Days	Average Daily Amount for Working Capital
1	FEDERAL INCOME TAX	($1,973)	$74,474	(37.75)	53.53	15.78	($31,132)	($85)
2	STATE INCOME TAX	($538)	$16,418	(30.50)	53.53	23.03	($12,397)	($34)
3	PURTA	$2,577	$157,191	61.00	53.53	114.53	$295,134	$809
4	PA CAPITAL STOCK TAX							
5	PA PROPERTY TAX	$1,677	$48,643	29.00	53.53	82.53	$138,431	$379
6	GROSS RECEIPTS TAX							

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Measures of Value at End of Test Year		$3,546,125
2	Long-Term Debt Ratio		46.50%
3	Embedded Cost of Long-Term Debt		5.64%
4	Pro Forma Interest Expense	L1 * L2 * L3	$93,001
5	Days in Current Year		365
6	Daily Amount	L4 / L5	$255
7	Days to Mid-Point of Interest Payments	L5 / 4	91.25
8	Less: Revenue Lag Days		53.53
9	Interest Payment Lag Days	L8 - L7	(37.72)
10	Total Interest for Working Capital	L6 * L9	**($9,611)**

($ in Thousands)

Line No.	Description	Reference	AGA Membership Dues	EAP Membership Dues	Northeast Gas Assoc.	OTD Tech Development	Maintenance	IT License & Maintenance	PUC Assessment Gas	Prepaid Rent	VEBA Adjust	Facilities Contracts	IT License & Maintenance	Fleet Activities	IT License & Maintenance	Customer Experience	Postage	Total Prepayment
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
1	December			$156			$23	$308	$1,335	$56	$3,449	$0	$27	$478	$172	$112	$566	
2	January			143		$130	15	219	973	39	3,449	(16)	14	498	166	232	580	
3	February			130		118	15	129	779	58	3,449	(32)	0	500	110	198	554	
4	March			117		106	15	40	584	42	2,376	150	0	503	82	439	538	
5	April			104		95	15	40	389	25	2,376	134	0	528	136	378	540	
6	May		$397	91		83	15	(50)	195	44	2,376	117	0	527	237	340	489	
7	June		397	78		71	15	(50)	0	28	1,888	100	0	530	484	302	499	
8	July		397	65		59	15	(50)	1,198	14	1,888	84	0	562	405	264	445	
9	August		91	52	$58	47	15	624	1,013	(3)	1,888	67	0	445	356	226	520	
10	September		67	39	43	35	15	624	2,128	71	2,231	50	0	471	306	188	655	
11	October		41	26	29	24	15	624	1,892	54	2,231	33	0	470	256	150	748	
12	November		15	13	14	12	15	624	1,655	39	2,231	17	0	500	318	112	748	
13	December		(24)				15	404	1,419	58	2,048	0	0	505	271	74	942	
14																		
15	Total	SUM L1 to L13	$1,382	$1,015	$144	$781	$205	$3,484	$13,558	$526	$31,883	$704	$41	$6,517	$3,299	$3,016	$7,825	
16																		
17	Distribution Percentage		100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	23.02%	23.02%	23.02%	23.02%	25.48%	25.48%	25.48%	
18																		
19	Distribution Amount	L15 * L17	$1,382	$1,015	$144	$781	$205	$3,484	$13,558	$526	$7,339	$162	$9	$1,500	$841	$769	$1,994	
20																		
21	Number of Months	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	13	
22																		
23	Monthly Average	L19 / L21	$106	$78	$11	$60	$16	$268	$1,043	$40	$565	$12	$1	$115	$65	$59	$153	
24																		
25	**Rate Case Amount**																	**$2,593**

		(1)	(2)	(3)
Line No.	Description	Shopping Percentage	Weighted Lag Days	Lag Days
1	Residential	56%		40.00
2	Nonresidential	44%		40.00
3	Weighted Payment Lag Days		40.00	
4				
5	Billing and Revenue Days Lag			1.00
6	Billing Lag (Average Period)			15.21
7	Total Payment Lag Days			56.21

		(1)	(2)
Line No.	Description	Reference	Pension Asset
1	Balance at End of HTY - Total		$441,490
2	Allocation % to Utility		18.56%
3	Utility Amount	L4 * L5	$81,940
4	Allocation % to Distribution Capital		42.01%
5	Balance at End of HTY - Distribution Capital	L6 * L7	**$34,423**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - CIAC		($4,716)	100.00%	($4,716)	100.00%	($4,716)
2		ADIT - Common Plant		106,546	100.00%	106,546	23.02%	24,527
3		ADIT - Gas Distribution		250,622	100.00%	250,622	100.00%	250,622
4		ADIT - Corporate Alternative Minimum Tax		(65,387)	100.00%	(65,387)	100.00%	(65,387)
5		**Total**	SUM L1 to L4	$287,064		$287,064		$205,045

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Residential	Non-Residential	Total
1	December		$4,220	$8,545	$12,765
2	January		4,235	8,434	12,669
3	February		4,342	8,568	12,910
4	March		4,548	8,856	13,404
5	April		4,832	9,143	13,975
6	May		5,032	9,347	14,379
7	June		5,094	9,381	14,475
8	July		5,198	9,471	14,669
9	August		5,305	9,539	14,845
10	September		5,457	9,677	15,134
11	October		5,614	9,861	15,475
12	November		5,723	9,900	15,623
13	December		5,791	10,091	15,882
14					
15	Total	SUM L1 to L13	$65,392	$120,814	$186,205
16					
17	Average Monthly Balance	L15 / 13	$5,030	$9,293	$14,323
18					
19	**HTY Deposits by Customer Classification**				
20	Residential				$5,030
21	Small C&I				8,785
22	Large C&I				508
23	Transportation				
24					
25	Total	SUM L20 to L23			$14,323

($ in Thousands)

Line No.	Category	Account	(1) Reference	(2) HTY Amount	(3) Allocated to Non Jurisdiction	(4) Allocated to Jurisdiction
1	**Common Plant in Service:**					
2						
3		E301 - Organization Costs		$677	$521	$156
4						
5		E303 - Misc Intangible Plant		$288,498	$222,086	$66,412
6						
7		E389 - Land and Land Rights		$6,770	$5,209	$1,560
8						
9		E390 - Structures and Improvements		$424,901	$327,089	$97,812
10		E391 - Office Furniture, Equipment		$85,851	$66,088	19,763
11		E392 - Transportation Equipment		$229,264	$176,487	52,776
12		E393 - Stores Equipment		$1,758	$1,353	405
13		E394 - Tools, Shop, Garage Equipmnt		$2,880	$2,217	663
14		E396 - Power Operated Equipment		$870	$670	200
15		E397 - Communication Equipment		$127,674	$98,284	29,391
16		E398 - Miscellaneous Equipment		$852	$656	196
17		E399 - Other Tangible Property				
18		E399.1 - ARO Costs General Plant		$337	$259	78
19		Sub Total - General Plant	SUM L9 to L18	$874,386	$673,102	$201,284
20		Total Common Plant in Service	SUM L3+L5+L7+L19	$1,170,330	$900,918	$269,412
21						
22	**Common Plant Accumulated Depreciation:**					
23						
24		E301 - Organization Costs				
25						
26		E303 - Misc Intangible Plant		$173,818	$133,805	$40,013
27						
28		E389 - Land and Land Rights				
29						
30		E390 - Structures and Improvements		$73,945	$56,923	$17,022
31		E391 - Office Furniture, Equipment		33,550	25,826	7,723
32		E392 - Transportation Equipment		104,912	80,761	24,151
33		E393 - Stores Equipment		479	369	110
34		E394 - Tools, Shop, Garage Equipmnt		1,223	942	282
35		E396 - Power Operated Equipment		268	207	62
36		E397 - Communication Equipment		50,163	38,616	11,548
37		E398 - Miscellaneous Equipment		872	671	201
38		E399 - Other Tangible Property				
39		E399.1 - ARO Costs General Plant		(360)	(277)	(83)
40		Sub Total - General Plant	SUM L30 to L39	$265,053	$204,038	$61,015
41		Total Common Plant Accum Depreciation	SUM L24+L26+L28+L40	$438,871	$337,843	$101,028
42						
43		Net Common Plant	L20 - L41	$731,460	$563,076	$168,384
44						
45						
46		Common Plant in Service to Utility	L20	$1,170,330	$900,918	$269,412
47		Common Plant Accum Depreciation to Utility	L41	438,871	337,843	101,028
48		Net Common Plant to Utility	L46 - L47	$731,460	$563,076	$168,384

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
C-9 Customer Advances For Construction

Line No.	Description	(1) Total HTY Amount
1	HTY 13-Month Average	
2	December	$964
3	January	1,037
4	February	1,033
5	March	1,043
6	April	1,198
7	May	1,270
8	June	1,295
9	July	1,436
10	August	1,480
11	September	1,480
12	October	1,981
13	November	1,974
14	December	2,014
15		
16	13-Month Total	$18,204
17		
18		
19	Average Monthly Balance	$1,400

($ in Thousands)

		(1)	(2)	(3)	(4)
Line No.	Description	Reference	Materials & Supplies	Undistributed Stores Expense	Total
1	HTY 13-Month Average				
2	December		$552	$0	$552
3	January		577	(535)	42
4	February		559	(319)	240
5	March		588	(560)	28
6	April		602	(2,433)	(1,831)
7	May		595	(911)	(316)
8	June		952	(1,049)	(97)
9	July		965	(1,747)	(782)
10	August		856	(2,066)	(1,209)
11	September		1,438	(2,581)	(1,143)
12	October		1,396	(2,857)	(1,462)
13	November		1,423	(2,421)	(998)
14	December		1,432	0	1,432
15					
16	Total	SUM L2 to L14	$11,934	($17,478)	($5,544)
17					
18	Distribution Expense Allocation Factor		100.00%	23.02%	
19					
20	Allocation to Distribution	L16 * L18	$11,934	($4,023)	
21					
22	Average Monthly Balance	L20 / 13	$918	($309)	**$608**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Test Year	Description	Reference	Total Amount	Percent to Utility	Utility Amount	Percent to Distribution	Distribution Amount
1	**HTY**	ADIT - Distribution		$109,004	100.00%	$109,004	100.00%	$109,004
2		ADIT - CIAC			100.00%		100.00%	
3		**Total**	L1 + L2	109,004		109,004		109,004

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
C-13 Gas Storage

		(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	Stored Underground	LNG	Propane Gas	Total
1	December		$31,540	$3,928	$1,527	$36,995
2	January		21,596	3,071	1,527	26,195
3	February		13,954	2,966	1,481	18,401
4	March		10,871	2,907	1,481	15,259
5	April		11,311	2,857	1,481	15,649
6	May		16,991	2,804	1,481	21,276
7	June		22,340	3,219	1,481	27,041
8	July		28,648	3,738	1,570	33,956
9	August		35,448	4,008	1,710	41,166
10	September		40,349	3,962	1,710	46,021
11	October		44,863	3,912	1,710	50,485
12	November		44,665	3,873	1,710	50,247
13	December		37,749	3,774	1,693	43,216
14						
15	Total	SUM L1 to L13	$360,324	$45,018	$20,564	$425,907
16						
17	Average Monthly Balance	L15 / 13	$27,717	$3,463	$1,582	$32,762

($ in Thousands)

			(1)	(2)	(3)	(4)
Line No.	Category	Description	Reference	Pro Forma Adjusted at Present Rates	Proposed Rate Increase	Adjusted Amounts with Proposed Rate Increase
1	**Operating Revenues**	Residential		$609,556		$609,556
2		C & I		211,122		211,122
3		Interdepartmental				
4		Sales for Resale				
5		Forfeited Discounts		2,457	43	2,500
6		Miscellaneous Service Revenues				
7		Rent For Gas Property		2,660		2,660
8		Other Gas Revenues		964		964
9		Transportation of Gas of Others		37,294		37,294
10		Revenue Increase			16,110	16,110
11		Subtotal Operating Revenues	SUM L1 to L10	$864,053	$16,153	$880,205
12						
13	**Operating Expenses**	Manufactured Gas Production		$442		$442
14		Storage Operations Expense		1,620		1,620
15		Storage Maintenance Expense		5,928		5,928
16		Underground Storage Expenses				
17		Other Gas Supply		286,675		286,675
18		Distribution Expense		78,760		78,760
19		Total Customer Accounts		22,458	84	22,542
20		Total Customer Service & Information		8,676		8,676
21		Total Sales		781		781
22		Administrative & General		52,243	73	52,316
23		O&M Expense	SUM L13 to L22	$457,583	$157	$457,740
24						
25		Depreciation & Amortization Expense		$111,494		$111,494
26		Amortization of Regulatory Expense		1,929		1,929
27		Taxes Other Than Income Taxes - Other		8,263		8,263
28		Subtotal Operating Expenses	SUM L23 to L27	$579,269	$157	$579,426
29						
30	**Net Operating Income - BIT**		L11 - L28	$284,784	$15,996	$300,779

($ in Thousands)

Line No.	Category	Description	(1) HTY Amount Pre Adjustments	(2) Adjustments Sub-Total	(3) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	$592,646	$16,910	$609,556
2		C & I	206,076	5,046	211,122
3		Interdepartmental			
4		Sales for Resale	14,675	(14,675)	
5		Forfeited Discounts	2,457		2,457
6		Miscellaneous Service Revenues			
7		Rent For Gas Property	2,660		2,660
8		Other Gas Revenues	951	13	964
9		Transportation of Gas of Others	37,268	26	37,294
10		Revenue Increase			
11		Subtotal Operating Revenues	$856,732	$7,321	$864,053
12					
13	**Operating Expenses**	Manufactured Gas Production	$434	$8	$442
14		Storage Operations Expense	1,588	32	1,620
15		Storage Maintenance Expense	5,828	100	5,928
16		Underground Storage Expenses			
17		Other Gas Supply	297,063	(10,388)	286,675
18		Distribution Expense	79,570	(810)	78,760
19		Total Customer Accounts	24,562	(2,104)	22,458
20		Total Customer Service & Information	8,669	6	8,676
21		Total Sales	769	12	781
22		Administrative & General	50,530	1,713	52,243
23		O&M Expense	$469,013	($11,430)	$457,583
24					
25		Depreciation & Amortization Expense	$104,499	$6,995	$111,494
26		Amortization of Regulatory Expense	1,459	470	1,929
27		Taxes Other Than Income Taxes - Other	8,100	163	8,263
28		Subtotal Operating Expenses	$583,072	($3,802)	$579,269
29					
30	**Net Operating Income - BIT**		**$273,661**	**$11,123**	**$284,784**

($ in Thousands)

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Category	Description	Description	HTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Leap Year Adjustment	D-5E Weather Normalization	D-5E Asset Optimization - Margin Adjustment	D-5F Weather Normal Adjustment	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits
1	**Operating Revenues**	Residential	Gas Cost	$219,588									
2			Cust & Dist	373,058	923	(270)	422	1,027		14,809			
3			Subtotal Residential	$592,646	$923	($270)	$422	$1,027		$14,809			
4													
5		C & I	Gas Cost	$67,857									
6			Cust & Dist	138,219	(68)		150	682		4,282			
7			Subtotal C & I	$206,076	($68)		$150	$682		$4,282			
8													
9		Interdepartmental	Gas Cost										
10			Subtotal Interdepartmental										
11													
12		Sales for Resale	Sales For Resale	$14,675					(14,675)				
13			Subtotal Sales for Resale	$14,675					($14,675)				
14													
15		Forfeited Discounts	Forfeited Discounts	$2,457									
16			Subtotal Forfeited Discounts	$2,457									
17													
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues										
19			Subtotal Miscellaneous Service Revenues										
20													
21		Rent For Gas Property	Rent for Gas Property	$2,660									
22			Subtotal Rent For Gas Property	$2,660									
23													
24		Other Gas Revenues	Other Gas Revenues	$951						13			
25			Subtotal Other Gas Revenues	$951						$13			
26													
27		Transportation of Gas of Others	Transportation of Gas of Others	$37,268				(251)		277			
28			Subtotal Transportation of Gas of Others	$37,268				($251)		$277			
29													
30		Revenue Increase	Revenue Increase										
31			Subtotal Revenue Increase										
32													
33			**Total Operating Revenues**	**$856,732**	**$854**	**($270)**	**$572**	**$1,458**	**($14,675)**	**$19,381**			
34													
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production										
36			Liquefied Petroleum Gas Expenses	162							3		
37			Liquefied Petroleum Gas Expenses	(165)									
38			Maintenance of Structures and Improvements	167							2		
39			Maintenance of Production Equipment	270							4		
40			Subtotal Manufactured Gas Production	$434							$8		
41													
42		Other Gas Supply	Natural Gas City Gate Purchases	$298,802					(10,388)				
43			Other Gas Purchases										
44			Purchases Gas Cost Adjustments	1,018									
45			Purchased Gas Expenses										

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
FTY Ending Dec. 2026
($ in Thousands)
D-3 Adj.'s to Net Operating Income

Line No.	Category	Description	Description	(1) HTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5E Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-5F Weather Normal Adjustment	(8) D-6 Salary & Wages	(9) D-7 Rate Case Expense	(10) D-8 Adjustments for Employee Benefits
46			Gas Withdrawn from Storage-Debit	35,177									
47			Gas Delivered to Storage-Credit	(41,232)									
48			Other Gas Supply Purchases	3,298									
49			Subtotal Other Gas Supply	$297,063					($10,388)				
50													
51		Storage Maintenance Expense	Maintenance Supervision and Engineering	$1,163							$23		
52			Maintenance of Structures and Improvements	4,665							77		
53			Subtotal Storage Maintenance Expense	$5,828							$100		
54													
55		Storage Operations Expense	Operating Supervision and Engineering	$471							$10		
56			Operation Labor and Expenses	1,117							23		
57			Subtotal Storage Operations Expense	$1,588							$32		
58													
59		Underground Storage Expenses	Other Expenses										
60			Subtotal Underground Storage Expenses										
61													
62		Distribution Expense	Operation Supervision and Engineering	$975							$1		
63			Mains and Services Expenses	22,179							$413		
64			Measuring and Regulating Station Expenses-General	1,346							$38		
65			Measuring and Regulating Station Expenses-City Gate	0									
66			Meter and House Regulator Expenses	5,805							$81		
67			Customer Installations Expenses	7,593							$234		
68			Other Expenses	18,805							$179		
69			Rents	213									
70			Maintenance of Mains	18,454							$350		
71			Maintenance of Measuring & Reg. Station Equip.-Genl.	745							$17		
72			Maintenance of Services	2,612							$57		
73			Maintenance of Meters & House Regulators	179							$5		
74			Maintenance of Other Equipment	665							$2		
75			Subtotal Distribution Expense	$79,570							$1,378		
76													
77		Total Customer Accounts	Customer Records and Collection	$17,602							$251		
78			Meter Reading	38									
79			Miscellaneous Customer Accounts	871							$11		
80			Uncollectible Accounts	6,051									
81			Subtotal Total Customer Accounts	$24,562							$262		
82													
83		Total Customer Service & Information	Customer Assistance	$8,043							$6		
84			Informational & Instructional	626									
85			Miscellaneous Customer & Informational										
86			Subtotal Total Customer Service & Information	$8,669							$6		
87													
88		Total Sales	Demonstrating & Selling	$769							$12		
89			Miscellaneous Sales										
90			Subtotal Total Sales	$769							$12		

($ in Thousands)

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)
Line No.	Category	Description	Description	HTY Amount Pre Adjustments	D-5A Revenue Annualization	D-5B CAP Revenue Credits and Adjustments	D-5C Leap Year Adjustment	D-5E Weather Normalization	D-5E Asset Optimization - Margin Adjustment	D-5F Weather Normal Adjustment	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits
91													
92		Administrative & General	Administrative and General Salaries	$5,912							$323		
93			Administrative Expenses Transferred-Credit										
94			Duplicate Charges-Credit	(74)									
95			Employee Pensions and Benefits	7,812									64
96			Franchise Requirements	10,176									
97			Injuries and Damages								$5		
98			Maintenance of General Plant	1,103							$7		
99			Miscellaneous General Expenses	608							$0		
100			Office Supplies and Expenses	787									
101			Outside Service Employed	20,437									
102			Property Insurance	192									
103			Regulatory Commission Expenses	3,578								780	
104			Subtotal Administrative & General	$50,530							$335	$780	$64
105													
106			**O&M Expense**	**$469,013**					**($10,388)**		**$2,134**	**$780**	**$64**
107													
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense	$104,499									
109			Subtotal Depreciation & Amortization Expense	$104,499									
110													
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense	$1,459									
112			Subtotal Amortization of Regulatory Expense	$1,459									
113													
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other	$8,100									
115			Subtotal Taxes Other Than Income Taxes - Other	$8,100									
116													
117			**Total Operating Expenses**	**$583,072**					**($10,388)**		**$2,134**	**$780**	**$64**
118													
119	**Net Operating Income Before Income Tax**			**$273,661**	**$854**	**($270)**	**$572**	**$1,458**	**($4,286)**	**$19,381**	**($2,134)**	**($780)**	**($64)**

($ in Thousands)

Line No.	Category	Description	Description	(11) D-9 Adjustments for Pension	(12) D-10 Uncollectible Accounts	(13) D-11 Energy Efficiency	(14) D-12 Customer Deposit Interest	(15) D-13 MGP Recovery	(16) D-14 MGP Interest and FTAC	(17) D-15 GPC / MFC	(18) D-16 Taxes Other Than Income	(19) D-17 Depreciation Annualization	(20) Adjustments Sub-total	(21) Pro Forma Adjusted at Present Rates
1	**Operating Revenues**	Residential	Gas Cost											$219,588
2			Cust & Dist										$16,910	389,968
3			Subtotal Residential										$16,910	$609,556
4														
5		C & I	Gas Cost											$67,857
6			Cust & Dist										$5,046	143,265
7			Subtotal C & I										$5,046	$211,122
8														
9		Interdepartmental	Gas Cost											
10			Subtotal Interdepartmental											
11														
12		Sales for Resale	Sales For Resale										($14,675)	
13			Subtotal Sales for Resale										($14,675)	
14														
15		Forfeited Discounts	Forfeited Discounts											$2,457
16			Subtotal Forfeited Discounts											$2,457
17														
18		Miscellaneous Service Revenues	Miscellaneous Service Revenues											
19			Subtotal Miscellaneous Service Revenues											
20														
21		Rent For Gas Property	Rent for Gas Property											2,660
22			Subtotal Rent For Gas Property											2,660
23														
24		Other Gas Revenues	Other Gas Revenues										$13	$964
25			Subtotal Other Gas Revenues										$13	$964
26														
27		Transportation of Gas of Others	Transportation of Gas of Others										$26	$37,294
28			Subtotal Transportation of Gas of Others										$26	$37,294
29														
30		Revenue Increase	Revenue Increase											
31			Subtotal Revenue Increase											
32														
33			**Total Operating Revenues**										**$7,321**	**$864,053**
34														
35	**Operating Expenses**	Manufactured Gas Production	Manufactured Gas Production											
36			Liquefied Petroleum Gas Expenses										$3	165
37			Liquefied Petroleum Gas Expenses											(165)
38			Maintenance of Structures and Improvements										$2	169
39			Maintenance of Production Equipment										$4	274
40			Subtotal Manufactured Gas Production										$8	$442
41														
42		Other Gas Supply	Natural Gas City Gate Purchases										($10,388)	$288,414
43			Other Gas Purchases											
44			Purchases Gas Cost Adjustments											1,018
45			Purchased Gas Expenses											

($ in Thousands)

				(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Line No.	Category	Description	Description	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 Energy Efficiency	D-12 Customer Deposit Interest	D-13 MGP Recovery	D-14 MGP Interest and FTAC	D-15 GPC / MFC	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
46			Gas Withdrawn from Storage-Debit											35,177
47			Gas Delivered to Storage-Credit											(41,232)
48			Other Gas Supply Purchases											3,298
49			Subtotal Other Gas Supply										($10,388)	$286,675
50														
51		Storage Maintenance Expense	Maintenance Supervision and Engineering										$23	$1,186
52			Maintenance of Structures and Improvements										$77	4,742
53			Subtotal Storage Maintenance Expense										$100	$5,928
54														
55		Storage Operations Expense	Operating Supervision and Engineering										$10	$481
56			Operation Labor and Expenses										$23	1,139
57			Subtotal Storage Operations Expense										$32	$1,620
58														
59		Underground Storage Expenses	Other Expenses											
60			Subtotal Underground Storage Expenses											
61														
62		Distribution Expense	Operation Supervision and Engineering										$1	$975
63			Mains and Services Expenses										$413	22,593
64			Measuring and Regulating Station Expenses-General										$38	1,384
65			Measuring and Regulating Station Expenses-City Gate											0
66			Meter and House Regulator Expenses										$81	5,886
67			Customer Installations Expenses										$234	7,827
68			Other Expenses							(2,188)			($2,009)	16,795
69			Rents											213
70			Maintenance of Mains										$350	18,804
71			Maintenance of Measuring & Reg. Station Equip.-Genl.										$17	762
72			Maintenance of Services										$57	2,669
73			Maintenance of Meters & House Regulators										$5	184
74			Maintenance of Other Equipment										$2	668
75			Subtotal Distribution Expense							($2,188)			($810)	$78,760
76														
77		Total Customer Accounts	Customer Records and Collection										$251	$17,853
78			Meter Reading											38
79			Miscellaneous Customer Accounts				684		$4				$700	1,570
80			Uncollectible Accounts		(1,093)					(1,961)			($3,054)	2,996
81			Subtotal Total Customer Accounts		($1,093)		$684		$4	($1,961)			($2,104)	$22,458
82														
83		Total Customer Service & Information	Customer Assistance										$6	$8,050
84			Informational & Instructional											626
85			Miscellaneous Customer & Informational											
86			Subtotal Total Customer Service & Information										$6	$8,676
87														
88		Total Sales	Demonstrating & Selling										$12	$781
89			Miscellaneous Sales											
90			Subtotal Total Sales										$12	$781

($ in Thousands)

				(11)	(12)	(13)	(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)
Line No.	Category	Description	Description	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 Energy Efficiency	D-12 Customer Deposit Interest	D-13 MGP Recovery	D-14 MGP Interest and FTAC	D-15 GPC / MFC	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
91														
92		Administrative & General	Administrative and General Salaries										$323	$6,235
93			Administrative Expenses Transferred-Credit											
94			Duplicate Charges-Credit											(74)
95			Employee Pensions and Benefits	534									$598	8,410
96			Franchise Requirements											10,176
97			Injuries and Damages										$5	5
98			Maintenance of General Plant										$7	1,110
99			Miscellaneous General Expenses										$0	608
100			Office Supplies and Expenses											787
101			Outside Service Employed											20,437
102			Property Insurance											192
103			Regulatory Commission Expenses										$780	4,358
104			Subtotal Administrative & General	$534									$1,713	$52,243
105														
106			**O&M Expense**	**$534**	**($1,093)**		**$684**		**$4**	**($4,149)**			**($11,430)**	**$457,583**
107														
108		Depreciation & Amortization Expense	Depreciation & Amortization Expense									$6,995	$6,995	$111,494
109			Subtotal Depreciation & Amortization Expense									$6,995	$6,995	$111,494
110														
111		Amortization of Regulatory Expense	Amortization of Regulatory Expense			$438		$32					$470	$1,929
112			Subtotal Amortization of Regulatory Expense			$438		$32					$470	$1,929
113														
114		Taxes Other Than Income Taxes - Other	Taxes Other Than Income Taxes - Other								$163		$163	$8,263
115			Subtotal Taxes Other Than Income Taxes - Other								$163		$163	$8,263
116														
117			**Total Operating Expenses**	**$534**	**($1,093)**	**$438**	**$684**	**$32**	**$4**	**($4,149)**	**$163**	**$6,995**	**($3,802)**	**$579,269**
118														
119	**Net Operating Income Before Income Tax**			**($534)**	**$1,093**	**($438)**	**($684)**	**($32)**	**($4)**	**$4,149**	**($163)**	**($6,995)**	**$11,123**	**$284,784**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
D-4 Expense Adjustment Summary

Line No.	Category	Description	Account	(1) HTY Amount Pre Adjustments	(2) D-5E Asset Optimization - Margin Adjustment	(3) D-6 Salary & Wages	(4) D-7 Rate Case Expense	(5) D-8 Adjustments for Employee Benefits	(6) D-9 Adjustments for Pension	(7) D-10 Uncollectible Accounts	(8) D-11 Energy Efficiency
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.								
2			717.0 Liquefied Petroleum Gas Expenses.	162		3					
3			741.0 Maintenance Of Structures And Improvements.	167		2					
4			742.0 Maintenance Of Production Equipment.	270		4					
5			Subtotal	$599		$8					
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.	(165)							
8			Subtotal	($165)							
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.	$298,802	($10,388)						
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.	1,018							
13			807.0 Purchased Gas Expenses.								
14			808.1 Gas Withdrawn From Storage-Debit.	35,177							
15			808.2 Gas Delivered To Storage-Credit.	(41,232)							
16			813.0 Other Gas Supply Expenses.	3,298							
17			Subtotal	$297,063	($10,388)						
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.	$471		$10					
23			841.0 Operation Labor And Expenses.	1,117		23					
24			Subtotal	$1,588		$32					
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.	$1,163		$23					
27			843.2 Maintenance Of Structures And Improvements.	4,665		77					
28			Subtotal	$5,828		$100					
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.	$975		$1					
31			874.0 Mains And Services Expenses.	22,179		413					
32			875.0 Measuring And Regulating Station Expenses--General.	1,346		38					
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.	0							
34			878.0 Meter And House Regulator Expenses.	5,805		81					
35			879.0 Customer Installations Expenses.	7,593		234					
36			880.0 Other Expenses.	18,805		179					
37			881.0 Rents.	213							
38			Subtotal	$56,916		$945					
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.	$18,454		$350					
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	745		17					
42			892.0 Maintenance Of Services.	2,612		57					
43			893.0 Maintenance Of Meters And House Regulators.	179		5					
44			894.0 Maintenance Of Other Equipment.	665		2					
45			Subtotal	$22,655		$433					
46											
47			Distribution Expense Subtotal	$79,570		$1,378					
48											

($ in Thousands)

				(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
Line No.	Category	Description	Account	HTY Amount Pre Adjustments	D-5E Asset Optimization - Margin Adjustment	D-6 Salary & Wages	D-7 Rate Case Expense	D-8 Adjustments for Employee Benefits	D-9 Adjustments for Pension	D-10 Uncollectible Accounts	D-11 Energy Efficiency
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.	$38		$0					
50			903.0 Customer Records And Collection Expenses.	17,602		251					
51			904.0 Uncollectible Accounts.	6,051						(1,093)	
52			905.0 Miscellaneous Customer Accounts Expenses.	871		11					
53											
54			Subtotal	$24,562		$262				($1,093)	
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses	$8,043		$6					
57			909.0 Informational And Instructional Advertising Expenses.	626							
58			910.0 Miscellaneous Customer Service And Informational Expenses.								
59			Subtotal	$8,669		$6					
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.	$769		$12					
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal	$769		$12					
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.	$5,912		$323					
66			921.0 Office Supplies And Expenses.	787							
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.	20,437							
69			924.0 Property Insurance.	192							
70			925.0 Injuries And Damages.	10,176		5					
71			926.0 Employee Pensions And Benefits.	7,812				64	534		
72			928.0 Regulatory Commission Expenses.	3,578			780				
73			929.0 Duplicate Charges--Credit.	(74)							
74			930.2 Miscellaneous General Expenses.	608		0					
75											
76			Subtotal	$49,427		$328	$780	$64	$534		
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.	$1,103		$7					
79			Subtotal	$1,103		$7					
80											
81			A&G Expense Sub-total	$50,530		$335	$780	$64	$534		
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.	$89,877							
84			403.1 Depreciation Expense - ARO/FIN-47								
85			404.0 Amort. Of Limited-Term Plant	14,622							
86			Subtotal	$104,499							
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.	$1,459							$438
89			Subtotal	$1,459							$438
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.	$8,100							
92			Subtotal	$8,100							
93											
94			**Total**	**$583,072**	**($10,388)**	**$2,134**	**$780**	**$64**	**$534**	**($1,093)**	**$438**

($ in Thousands)

				(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)
Line No.	Category	Description	Account	D-12 Customer Deposit Interest	D-13 MGP Recovery	D-14 MGP Interest	D-15 GPC / MFC	D-16 Taxes Other Than Income	D-17 Depreciation Annualization	Adjustments Sub-total	Pro Forma Adjusted at Present Rates
1	**MANUFACTURED GAS PRODUCTION EXPENSES**	**Manufactured Gas Production**	710.0 Operation Supervision And Engineering.								
2			717.0 Liquefied Petroleum Gas Expenses.							3	165
3			741.0 Maintenance Of Structures And Improvements.							2	169
4			742.0 Maintenance Of Production Equipment.							4	274
5			Subtotal							$8	$608
6											
7	**GAS RAW MATERIALS**	**Gas Raw Materials**	728.0 Liquefied Petroleum Gas.								(165)
8			Subtotal								($165)
9											
10	**OTHER GAS SUPPLY EXPENSES**	**Other Gas Supply**	804.0 Natural Gas City Gate Purchases.							($10,388)	$288,414
11			805.0 Other Gas Purchases.								
12			805.1 Purchased Gas Cost Adjustments.								1,018
13			807.0 Purchased Gas Expenses.								
14			808.1 Gas Withdrawn From Storage-Debit.								35,177
15			808.2 Gas Delivered To Storage-Credit.								(41,232)
16			813.0 Other Gas Supply Expenses.								3,298
17			Subtotal							($10,388)	$286,675
18											
19	**UNDERGROUND STORAGE EXPENSES**	**Underground Storage Expenses**	824.0 Other Expenses.								
20			Subtotal								
21											
22	**STORAGE EXPENSE**	**Storage Operations Expense**	840.0 Operation Supervision And Engineering.							$10	$481
23			841.0 Operation Labor And Expenses.							23	1,139
24			Subtotal							$32	$1,620
25											
26		**Storage Maintenance Expense**	843.1 Maintenance Supervision And Engineering.							$23	$1,186
27			843.2 Maintenance Of Structures And Improvements.							77	4,742
28			Subtotal							$100	$5,928
29											
30	**DISTRIBUTION EXPENSE**	**Distribution Operations**	870.0 Operation Supervision And Engineering.							$1	$975
31			874.0 Mains And Services Expenses.							413	22,593
32			875.0 Measuring And Regulating Station Expenses--General.							38	1,384
33			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.								0
34			878.0 Meter And House Regulator Expenses.							81	5,886
35			879.0 Customer Installations Expenses.							234	7,827
36			880.0 Other Expenses.				(2,188)			(2,009)	16,795
37			881.0 Rents.								213
38			Subtotal				($2,188)			($1,243)	$55,673
39											
40		**Distribution Maintenance**	887.0 Maintenance Of Mains.							$350	$18,804
41			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.							17	762
42			892.0 Maintenance Of Services.							57	2,669
43			893.0 Maintenance Of Meters And House Regulators.							5	184
44			894.0 Maintenance Of Other Equipment.							2	668
45			Subtotal							$433	$23,087
46											
47			Distribution Expense Subtotal				($2,188)			($810)	$78,760
48											

($ in Thousands)

Line No.	Category	Description	Account	(9) D-12 Customer Deposit Interest	(10) D-13 MGP Recovery	(11) D-14 MGP Interest	(12) D-15 GPC / MFC	(13) D-16 Taxes Other Than Income	(14) D-17 Depreciation Annualization	(15) Adjustments Sub-total	(16) Pro Forma Adjusted at Present Rates
49	**CUSTOMER ACCOUNTS**	**Customer Accounts**	902.0 Meter Reading Expenses.							$0	$38
50			903.0 Customer Records And Collection Expenses.							251	17,853
51			904.0 Uncollectible Accounts.				(1,961)			(3,054)	2,996
52			905.0 Miscellaneous Customer Accounts Expenses.	684		$4				700	1,570
53											
54			Subtotal	$684		$4	($1,961)			($2,104)	$22,458
55											
56	**CUSTOMER SERVICE & INFORMATION**	**Customer Service & Information**	908.0 Customer Assistance Expenses							$6	$8,050
57			909.0 Informational And Instructional Advertising Expenses.								626
58			910.0 Miscellaneous Customer Service And Informational Expenses.								
59			Subtotal							$6	$8,676
60											
61	**SALES**	**Sales**	912.0 Demonstrating And Selling Expenses.							$12	$781
62			916.0 Miscellaneous Sales Expenses.								
63			Subtotal							$12	$781
64											
65	**ADMINISTRATION & GENERAL**	**A&G Operations**	920.0 Administrative And General Salaries.							$323	$6,235
66			921.0 Office Supplies And Expenses.								787
67			922.0 Administrative Expenses Transferred--Credit.								
68			923.0 Outside Services Employed.								20,437
69			924.0 Property Insurance.								192
70			925.0 Injuries And Damages.							5	10,182
71			926.0 Employee Pensions And Benefits.							598	8,410
72			928.0 Regulatory Commission Expenses.							780	4,358
73			929.0 Duplicate Charges--Credit.								(74)
74			930.2 Miscellaneous General Expenses.							0	608
75											
76			Subtotal							$1,706	$51,133
77											
78		**A&G Maintenance**	932.0 Maintenance Of Gas General Plant.							$7	$1,110
79			Subtotal							$7	$1,110
80											
81			A&G Expense Sub-total							$1,713	$52,243
82											
83	**DEPRECIATION & AMORTIZATION EXPENSE**	**Depreciation & Amortization Expense**	403.0 Depreciation Expense.						$4,946	$4,946	$94,824
84			403.1 Depreciation Expense - ARO/FIN-47								-
85			404.0 Amort. Of Limited-Term Plant						2,049	2,049	16,670
86			Subtotal						$6,995	$6,995	$111,494
87											
88	**AMORTIZATION OF REGULATORY EXPENSE**	**Amortization of Regulatory Expense**	407.3 Regulatory Debits.		$32					$470	$1,929
89			Subtotal		$32					$470	$1,929
90											
91	**TAXES OTHER THAN INCOME TAXES**	**Taxes Other Than Income Taxes - Other**	408.1 Taxes Other Than Income Taxes, Utility Operating Income.					$163		$163	$8,263
92			Subtotal					$163		$163	$8,263
93											
94			**Total**	**$684**	**$32**	**$4**	**($4,149)**	**$163**	**$6,995**	**($3,802)**	**$579,269**

($ in Thousands)

Line No.	Category	Description	Description	Account	(1) HTY Amount Pre Adjustments	(2) D-5A Revenue Annualization	(3) D-5B CAP Revenue Credits and Adjustments	(4) D-5C Leap Year Adjustment	(5) D-5D Weather Normalization	(6) D-5E Asset Optimization - Margin Adjustment	(7) D-5F Weather Normal Adjustment	(8) Adjustments Sub-total	(9) Pro Forma Adjusted at Present Rates
1	*OPERATING REVENUE*	**Customer & Distribution Revenue**	Residential	480.0	$373,058	$923	($270)	$422	$1,027		$19,381	$21,482	$394,540
2			C & I	481.0	138,219	(68)		150	682			764	138,983
3			Transportation of Gas of Others	489.3	37,268				(251)			(251)	37,017
4				Subtotal	$548,545	$854	($270)	$572	$1,458		$19,381	$21,995	$570,540
5													
6		**Gas Cost Revenue**	Residential	480.0	$219,588								$219,588
7			C & I	481.0	67,857								67,857
8			Interdepartmental	484.0									
9				Subtotal	$287,445								$287,445
10													
11				**Subtotal OPERATING REVENUE**	$835,990	$854	($270)	$572	$1,458		$19,381	$21,995	$857,985
12													
13	*OTHER REVENUE*	**Other Gas Revenue**	Rent for Gas Property	493.0	$2,660								$2,660
14			Interdepartmental Rents	494.0									
15			Other Gas Revenues	495.0	951								951
16				Subtotal	$3,610								$3,610
17													
18		**Other Operating Revenue**	Sales For Resale	483.0	$14,675					($14,675)		($14,675)	
19			Forfeited Discounts	487.0	2,457								2,457
20													
21			Miscellaneous Service Revenues	488.0									
22				Subtotal	$17,132					($14,675)		($14,675)	$2,457
23													
24				**Subtotal OTHER REVENUE**	$20,742					($14,675)		($14,675)	$6,067
25													
26				**Total**	**$856,732**	**$854**	**($270)**	**$572**	**$1,458**	**($14,675)**	**$19,381**	**$7,321**	**$864,053**

($ in Thousands)

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Reference	480000: Residential Sales	481001: TCS Sales	481002: GC Sales	481003: L Sales	481005: Other Sales	C & I Total
1	Total HTY Revenues		$592,706	$727	$204,025	$189	$1,109	$206,050
2	Commodity Billings in Revenues		(219,647)	(258)	(67,075)	(70)	(428)	(67,831)
3	Weather Adjustment		1,027		682			682
4	Total Reconcilable Surcharge in Revenues		14,548					-
5	Revenues Net of Commodity - Margin	SUM L1 to L4	$388,633	$469	$137,632	$119	$681	$138,902
6								
7	Average Monthly Customers in HTY		509,749	21	44,678	6	16	
8								
9	Average Annual Margin Per Customer	L5 / L7	$0.762	$22.510	$3.081	$19.824	$42.576	
10								
11	Number of Customers of Current Month		510,959	20	44,662	6	16	44,704
12								
13	Increase in Customers During HTY	L11 - L7	1,210	(1)	(16)			44,704
14								
15	Annualization of Revenue	L9 * L13	$923	($19)	($50)			($68)

($ in Thousands)

D-5B - CAP Revenue Credits and Adjustments

Line No.	Description	(1) Reference	(2) Residential Sales
1	CAP Discount		($15,446)
2			
3			
4	**ANNUALIZATION TO YEAR END CUSTOMERS**		
5			
6	Annual CAP Customers		300,536
7	Average Monthly CAP Customers		25,045
8	Average Annual CAP Discount Per Customer	L1 / L7	($0.617)
9			
10	CAP Customers at End of HTY		25,541
11	Decrease of CAP Customers	L10 - L7	496
12			
13	Gross Decrease / (Increase) in CAP Discount	L8 * L11	($306)
14	Write-Offs & Working Capital Factor		11.9%
15	Reflect Impact in Write-Offs and Working Capital	- L13 * L14	$36
16			
17	**Net Decrease / (Increase) in CAP Discount**	L13 + L15	**($270)**

($ in Thousands)

D-5C - Leap Year Revenue Normalization

		(1)	(2)	(3)	(4)	(5)	(6)	(7)
Line No.	Description	Reference	480000: Residential Sales	481001: TCS Sales	481002: GC Sales	481003: L Sales	481005: Other Sales	C & I Total
1	Revenue in February of HTY		$47,289	($0)	$16,725	$4	$55	$16,783
2	Days in February of HTY		28	28	28	28	28	
3	Average Daily Revenue in February	L1 / L2	1,689	(0)	597	0	2	
4	Average Days in February		28.25	28.25	28.25	28.25	28.25	
5	Difference in Days	L4 - L2	0.25	0.25	0.25	0.25	0.25	
6								
7	**Leap Year Adjustment**	L3 * L5	**$422**	**($0)**	**$149**	**$0**	**$0**	**$150**

		(1)
Line No.	Description	Total
1	Residential Sales	$1,027
2	TCS Sales	
3	GC Sales	682
4	C & I Total	682
5	Revenues - Gas Transportation	(251)
6	**Total**	$1,458

Line No.	Description	Account	Total
			(1)
1	Other Operating Revenue	483000: Sales for Resale - Gas	($14,675)
2			
3	Purchased Fuel	804000: Natural Gas City Gate Purchases	($10,388)

D-5F - 30-Year vs. 10-Year Weather Normal Adjustment

Line No.	Description	(1) Total
1	Residential Sales	$14,809
2	TCS Sales	
3	GC Sales	4,278
4	Large C&I	4
5	Other	13
6	Transportation	277
7	**Total**	**$19,381**

($ in Thousands)

		(1)	(2)	(3)
Line No.	Description	Reference	Union	Non-Union
1	Number of Employees @ HTY - Union/Non-Union		354	341
2	Number of Employees @ HTY - Total		695	695
3	Percentage of Employees @ HTY	L1 / L2	50.92%	49.08%
4	Distribution of Budget S&W Expense		$25,223	$24,313
5				
6	**Annualize March 1 Wage Increase for HTY**			
7	Number of Months TY			2
8	Rate for Increase TY		3.00%	3.00%
9	Total Wage Increase TY	(L4 * L7 * L8) / 12		$122
10		L4 + L9	$25,223	$24,435
11				
12	**Annualize January 1 and March 1, 2026 Wage Increase**			
13	Number of Months		12	12
14	Rate for Increase		3.00%	3.00%
15	Total Adjustment	(L10 * L13 * L14) / 12	$757	$733
16				
17	**Annualized S&W Including Wage Increases**	L10 + L15	**$25,980**	**$25,168**

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	PECO - Gas
1	Distribution of S&W Expense		$49,536
2			
3	Annualized S&W Including Wage Increases		$51,147
4			
5	**Normalize Contract Payment to Union**		
6	Union Contract Payment		$1,303
7	Union Contract Payment % for Utility		18.56%
8	Union Contract Payment for Utility	L6 * L7	$242
9	Union Contract Payment Normalization Period		6
10	Union Contract Payment Normalized	L8 / L9	$40
11			
12	Annualized S&W for Employees in HTY	L3 + L10	$51,188
13			
14	**Pro Forma For New Employees**		
15	Number of Employees @ HTY		703
16	Average Number of Employees in FTY - Total		696
17	Annualization for Number of Employees	L15 - L16	7
18	Annual S&W per Employee	L12 / L16	$73.5
19	Annualization of S&W for New Employees	L17 * L18	$482
20			
21	Pro FormaFTY S&W	L12 + L19	$51,670
22			
23	**Pro Forma Increase in S&W**	L21 - L1	**$2,134**
24			
25	S&W Pro Forma Factor	L23 / L1	4.31%

($ in Thousands)

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
1	**Operations**	Power Supply Expenses	710.0 Operation Supervision And Engineering.			
2			717.0 Liquefied Petroleum Gas Expenses.	$59	3	$61
3			728.0 Liquefied Petroleum Gas.			
4			804.0 Natural Gas City Gate Purchases.			
5			805.0 Other Gas Purchases.			
6			805.1 Purchased Gas Cost Adjustments.			
7			807.0 Purchased Gas Expenses.			
8			808.1 Gas Withdrawn From Storage-Debit.			
9			808.2 Gas Delivered To Storage-Credit.			
10			813.0 Other Gas Supply Expenses.			
11			840.0 Operation Supervision And Engineering.	228	10	238
12			841.0 Operation Labor And Expenses.	525	23	547
13			843.1 Maintenance Supervision And Engineering.	528	23	551
14			843.2 Maintenance Of Structures And Improvements.	1,790	77	1,867
15			**Subtotal Power Supply Expenses**	$3,129	$135	$3,264
16						
17		Distribution Expense	870.0 Operation Supervision And Engineering.	$12	$1	$13
18			874.0 Mains And Services Expenses.	9,592	413	10,006
19			875.0 Measuring And Regulating Station Expenses--General.	873	38	911
20			877.0 Measuring And Regulating Station Expenses--City Gate Check Stations.			
21			878.0 Meter And House Regulator Expenses.	1,883	81	1,965
22			879.0 Customer Installations Expenses.	5,422	234	5,656
23			880.0 Other Expenses.	4,153	179	4,332
24			881.0 Rents.			
25			885.0 Maintenance Supervision And Engineering.			
26			887.0 Maintenance Of Mains.	8,133	350	8,483
27			889.0 Maintenance Of Measuring And Reg. Stn. Equip.--General.	405	17	422
28			892.0 Maintenance Of Services.	1,327	57	1,385
29			893.0 Maintenance Of Meters And House Regulators.	118	5	123
30			894.0 Maintenance Of Other Equipment.	57	2	59
31			**Subtotal Distribution Expense**	$31,977	$1,378	$33,354
32						
33		Customer Accounts	902.0 Meter Reading Expenses.	$0	$0	$0
34			903.0 Customer Records And Collection Expenses.	5,821	251	6,072
35			904.0 Uncollectible Accounts.			
36			905.0 Miscellaneous Customer Accounts Expenses.	257	11	269
37						
38			**Subtotal Customer Accounts**	$6,079	$262	$6,341
39						

($ in Thousands)

Line No.	Category	Description	Account	(1) Jurisdictional Payroll Amount	(2) Pro Forma Payroll Adjustment	(3) Total Adjusted Payroll
40		Customer Service & Information	908.0 Customer Assistance Expenses	$145	$6	$152
41			909.0 Informational And Instructional Advertising Expenses.			
42			910.0 Miscellaneous Customer Service And Informational Expenses.			
43			**Subtotal Customer Service & Information**	$145	$6	$152
44						
45		Sales	912.0 Demonstrating And Selling Expenses.	$282	$12	$294
46			916.0 Miscellaneous Sales Expenses.			
47			**Subtotal Sales**	$282	$12	$294
48						
49		Administration & General - General	920.0 Administrative And General Salaries.	$7,491	$323	$7,813
50			921.0 Office Supplies And Expenses.			
51			922.0 Administrative Expenses Transferred--Credit.			
52			923.0 Outside Services Employed.			
53			924.0 Property Insurance.			
54			925.0 Injuries And Damages.	126	5	131
55			926.0 Employee Pensions And Benefits.			
56			928.0 Regulatory Commission Expenses.			
57			929.0 Duplicate Charges--Credit.			
58			930.2 Miscellaneous General Expenses.	1	0	1
59						
60			**Subtotal Administration & General - General**	$7,617	$328	$7,945
61						
62			**Subtotal Operations**	$49,229	$2,121	$51,350
63						
64	**Maintenance**	Administration & General - General	932.0 Maintenance Of Gas General Plant.	$170	$7	$177
65			**Subtotal Administration & General - General**	$170	$7	$177
66						
67		Gas Expense	741.0 Maintenance Of Structures And Improvements.	$39	$2	$41
68			742.0 Maintenance Of Production Equipment.	98	4	102
69			**Subtotal Gas Expense**	$137	$6	$143
70						
71			**Subtotal Maintenance**	$307	$13	$321
72						
73	**Total Operations & Maintenance**		**Total Operations & Maintenance**	$49,536	$2,134	$51,670
74						
75	**Percent Increase**		**Percent Increase**			4.31%

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Amount
1	**EXPENDITURES UP TO PERIOD END OF HTY**		
2	External Legal and Consultants		$47
3	Staff Augmentation, Materials, IT Costs, Travel, Copies, etc.		31
4	**Total Recorded Up To Period End of HTY**	SUM L2 to L3	$78
5			
6	**EXPENDITURES IN FTY**		
7	External Legal and Consultants		$2,782
8	Materials, IT Costs, Travel, Copies, etc.		365
9	**Total Expenditure Expected in FTY**	SUM L7 to L8	$3,148
10			
11	**Total Rate Case Expense**	L4 + L9	$3,226
12			
13	Amortization Period		2
14	Annual Amortization Amount	L11 / L13	$1,613
15			
16	Annual Amortization Amount Included in Budget		$833
17	Pro Forma Adjustment for Annual Amortization	L14 - L16	**$780**

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	**Number of Employees**		
2	Employees at Eleven Months Prior		691
3	Employees at Ten Months Prior		692
4	Employees at Nine Months Prior		694
5	Employees at Eight Months Prior		694
6	Employees at Seven Months Prior		694
7	Employees at Six Months Prior		694
8	Employees at Five Months Prior		697
9	Employees at Four Months Prior		697
10	Employees at Three Months Prior		697
11	Employees at Two Months Prior		703
12	Employees at One Month Prior		703
13	Employees at End of HTY		703
14			
15	Average Monthly Employees in HTY	AVERAGE L2 to L13	696
16	Additional Employees in HTY		7
17			
18	**Employee Benefits**		
19	Total Benefits Expensed		$6,742
20	Number of Employees for Budget		696
21	Budget Expense Per Employee	L19 / L20	$10
22	Additional Employees for Annualization	L16	7
23	Total Benefits Pro Forma Adjustment	L21 * L22	**$64**

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Total - PECO
1	Pension Contribution for Four Years Prior to HTY		$17,267
2	Pension Contribution for Three Years Prior to HTY		15,222
3	Pension Contribution for Two Years Prior to HTY		1,408
4	Pension Contribution for One Year Prior to HTY		3,690
5	Pension Contribution for HTY		11,760
6			
7	Average Pension Contribution	AVERAGE L1 to L5	$9,869
8			
9	Allocation Percent to Utility		18.56%
10	Total Amount to Utility	L7 * L9	$1,832
11	Allocation Percent to Capital		42.01%
12	Pension Contribution To Be Capitalized	L10 * L11	$770
13	Pension Contribution To Be Expensed	L10 - L12	$1,062
14	Test Year Distribution Pension Expense		$528
15	Additional Pension Expense	L13 - L14	**$534**

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)
Line No.	Description	Reference	Reference	Charge Off Amounts	Billed Revenue	Percent	Totals
1	**NET GENERAL UNCOLLECTIBLE ACCOUNTS**	Two Years Prior to HTY		$3,091	$778,733	0.3970%	
2		One Year Prior to HTY		2,884	687,070	0.4197%	
3		HTY		6,465	912,486	0.7085%	
4		Three Year Average	SUM L1 to L3 / 3	$4,147	$792,763	0.5231%	
5							
6	Base Customer Charge & Energy Cost Revenue After Pro Formas	HTY			$857,985		
7							
8	Tariff Revenue - Non Shopping Revenue	HTY	L6		$857,985		
9							
10	Tariff Revenue - Shopping Revenue	HTY			$89,762		
11							
12	Tariff Revenue - Including Shopping Revenue	HTY	L8 + L10		$947,748		
13							
14	**Total General Pro Forma Uncollectible Accounts**		Col 4 L4 * L12				$4,957
15							
16	Uncollectible Accounts (904)	HTY					$6,051
17							
18	**Total Pro Forma Adjustment for Uncollectible Accounts**		L14 - L16				($1,093)

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
D-11 - Energy Efficiency Programs

Line No.	Description	(1) Reference	(2) Jurisdictional
1	Residential Natural Gas Energy Efficiency Program		$423
2	Commercial Natural Gas Energy Efficiency Program		42
3	Sub-total Pro Forma Increase in Gas Energy Efficiency Program Costs	L1 + L2	$464
4	Gas Commercial EE Program Refund - Rate GC		($52)
5	Amortization Years		2
6	Annual Amortization Amount of Gas Commercial EE Program Refund	L4 / L5	($26)
7	Total Gas Energy Efficiency Program Pro Forma Adjustment Amount	L3 + L6	$438

($ in Thousands)

			(1)	(2)	(3)	(4)	(5)	(6)
Line No.	Description	Description	Reference	Interest Rate	Deposit Amount	Interest on Deposit Amount	Interest Sub-Total	Interest Total
1	**Residential**	Monthly Interest Rate		0.583%				
2								
3	January				4,235	25		
4	February				4,342	25		
5	March				4,548	27		
6	April				4,832	28		
7	May				5,032	29		
8	June				5,094	30		
9	July				5,198	30		
10	August				5,305	31		
11	September				5,457	32		
12	October				5,614	33		
13	November				5,723	33		
14	December				5,791	34		
15	**Total Residential**		SUM Col 4 L3 to L14				$357	
16								
17	**Non-Residential**	Monthly Interest Rate		0.292%				
18								
19	January				8,434	25		
20	February				8,568	25		
21	March				8,856	26		
22	April				9,143	27		
23	May				9,347	27		
24	June				9,381	27		
25	July				9,471	28		
26	August				9,539	28		
27	September				9,677	28		
28	October				9,861	29		
29	November				9,900	29		
30	December				10,091	29		
31	**Total Non-Residential**		SUM Col 4 L19 to L30				$327	
32								
33	**Interest on Customer Deposits**		Col 5 L15 + L31					$684

		(1)	(2)
Line No.	Description	Reference	Total
1	Regulatory Asset for Unrecovered MGP Remediation Liability		$11,705
2	Amortization Years		8
3			
4	**Total Annual Amortization Amount**	L1/L2	$1,463
5			
6	**Amount Included in Budget**		$1,431
7			
8	**Pro Forma Adjustment Amount**	L4 - L6	**$32**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
D-14 Adjustments for MGP Interest and FTAC Reconciliation

Line No.	Description	Reference (1)	Total (2)
1	Customer Interest on Unspent MGP Collections		($1,316)
2	Amortization Years		2
3	Pro Forma Adjustment Amount	L3 / L4	($658)
4	Annual Amortization Amount Included in Budget		($662)
5	**Pro Forma Adjustment for Annual Amortization**	L3 - L4	**$4**

($ in Thousands)

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Gas Procurement Charge		
2	Rate GR		($1,408)
3	Rate GC		($766)
4	Rate L		($1)
5	Rate OL		
6	Rate MV-F		($13)
7	Total Gas Procurement Charge	SUM L2 to L6	($2,188)
8			
9	Merchant Function Charge / POR		
10	Rate GR		($1,665)
11	Rate GC		($296)
12	Rate L		
13	Rate OL		
14	Rate MV-F		
15	Total Merchant Function Charge / POR	SUM L10 to L14	($1,961)
16			
17	**Total Gas Procurement and Merchant Function Charges**	L7 + L15	**($4,149)**

($ in Thousands)

		(1)	(2)	(3)
Line No.	Description	Total	Pro Forma Adjustments	Pro Forma Tax Expense
1	Public Utility Real Tax (PURTA) Total Expense	$2,577		$2,577
2	Capital Stock & Franchise Tax	37		37
3	Use Tax Accrued	10		10
4	Real Estate Tax Accrual	1,677		1,677
5	Miscellaneous TOTI	15		15
6	Payroll Tax Accrued	3,784	$163	3,947
7	**Total**	**$8,100**	**$163**	**$8,263**

		(1)	(2)
Line No.	Description	Reference	Jurisdictional
1	Total Payroll Charged to Expense		$49,536
2	Payroll Tax Expense		$3,784
3	Payroll Tax Expense - Percent	L2 / L1	7.64%
4	Pro Forma Increase in S&W		$2,134
5	**Payroll Tax Pro Forma**	L3 * L4	**$163**

($ in Thousands)

				(1)	(2)	(3)	(4)	(5)
Line No.	Account	Plant Account	Depreciation Category	Depr on Existing Assets + Adds	Depr on Adds	Depr on Existing Assets	Annualize Current Yr Depr	Pro Forma Test Yr Depr
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	$4,522		$4,522		$4,522
2			PECO Common 3902 IL	16		16		16
3			PECO Common 3902 PA	3,367	677	2,691	677	4,044
4			PECO Common 3903 PA	310		310		310
5			PECO Common 3911 PA	13		13		13
6			PECO Common 3912 PA	2,278	41	2,237	41	2,318
7			PECO Common 3913 IL	3,026	1,980	1,046	1,980	5,005
8			PECO Common 3913 PA	7,501		7,501		7,501
9			PECO Common 3930 PA	116	10	107	10	126
10			PECO Common 3941 PA	0		0		0
11			PECO Common 3942 PA	66	0	66	0	67
12			PECO Common 3970 PA	5,948		5,948		5,948
13			PECO Common 3980 PA	139		139		139
14			Subtotal Common - General Plant	$27,303	$2,707	$24,596	$2,707	$30,010
15								
16		Gas - Distribution	PECO Gas 3751 PA	$229	$37	$193	$37	$266
17			PECO Gas 3752 PA	77	11	66	11	88
18			PECO Gas 3753 PA	146		146		146
19			PECO Gas 3761 PA	11,902	603	11,299	603	12,505
20			PECO Gas 3762 PA	1,363	106	1,258	106	1,469
21			PECO Gas 3763 PA	23,747	1,406	22,341	1,406	25,152
22			PECO Gas 3780 PA	594	58	537	58	652
23			PECO Gas 3790 PA	1,045	65	980	65	1,110
24			PECO Gas 3801 PA	3,793	47	3,746	47	3,841
25			PECO Gas 3802 PA	21,653	894	20,759	894	22,547
26			PECO Gas 3810 PA	2,199	72	2,127	72	2,271
27			PECO Gas 3811 PA	3,534	67	3,467	67	3,600
28			PECO Gas 3820 PA	5,287	326	4,961	326	5,612
29			PECO Gas 3870 PA	123	20	102	20	143
30			Subtotal Gas - Distribution	$75,692	$3,711	$71,981	$3,711	$79,403
31								

($ in Thousands)

Line No.	Account	Plant Account	Depreciation Category	(1) Depr on Existing Assets + Adds	(2) Depr on Adds	(3) Depr on Existing Assets	(4) Annualize Current Yr Depr	(5) Pro Forma Test Yr Depr
32		Gas - General Plant	PECO Gas 3901 PA	$98	$0	$98	$0	$99
33			PECO Gas 3902 PA	55		55		55
34			PECO Gas 3903 PA	70	0	70	0	70
35			PECO Gas 3911 PA	0		0		0
36			PECO Gas 3912 PA	41	1	40	1	42
37			PECO Gas 3913 IL					
38			PECO Gas 3913 PA	797	340	457	340	1,137
39			PECO Gas 3940 PA	1,002	68	934	68	1,070
40			PECO Gas 3950 PA	2		2		2
41			PECO Gas 3970 PA	544	191	352	191	735
42			PECO Gas 3980 PA	8		8		8
43			Subtotal Gas - General Plant	$2,617	$601	$2,016	$601	$3,219
44								
45		Gas - Production Plant	PECO Gas 3050 PA	$32		$32		$32
46			PECO Gas 3053 PA					
47			PECO Gas 3110 PA	151	3	148	3	154
48			Subtotal Gas - Production Plant	$183	$3	$181	$3	$186
49								
50		Gas - Storage	PECO Gas 3611 PA	$46		$46		$46
51			PECO Gas 3612 PA	293	0	292	0	293
52			PECO Gas 3613 PA	20		20		20
53			PECO Gas 3620 PA	9		9		9
54			PECO Gas 3630 PA	22		22		22
55			PECO Gas 3631 PA	141	0	141	0	142
56			PECO Gas 3632 PA	2,878		2,878		2,878
57			PECO Gas 3633 PA	771	7	765	7	778
58			PECO Gas 3634 PA	525	0	525	0	525
59			PECO Gas 3635 PA	394	1	393	1	395
60			Subtotal Gas - Storage	$5,100	$8	$5,092	$8	$5,108
61								
62			Subtotal 403.0 Depreciation Expense.	$110,895	$7,030	$103,865	$7,030	$117,925
63								

($ in Thousands)

				(1)	(2)	(3)	(4)	(5)
Line No.	Account	Plant Account	Depreciation Category	Depr on Existing Assets + Adds	Depr on Adds	Depr on Existing Assets	Annualize Current Yr Depr	Pro Forma Test Yr Depr
64	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 303-CFP B&P SW	$69	$69		$69	139
65			PECO Com 303-CFP MEU SW	$135		135		135
66			PECO Com 303-CFP MMA SW	$40	$40		$40	80
67			PECO Com 303-DSS Platform Enhanc SW	$67	$67		$67	135
68			PECO Com 303-EU Custom Hardening SW	$85	$85		$85	170
69			PECO Com 303-EU EAM SW	$59	$59		$59	118
70			PECO Com 303-EU EAM Transformation	$22	$22		$22	45
71			PECO Com 303-EU GIS Core SW	$560	$560		$560	1,119
72			PECO Com 303-EU Reliab-Auto SW	$12	$12		$12	23
73			PECO Com 303-Grid FR Workstream SW	$12	$12		$12	25
74			PECO Com 303-IGA Enhance Prog SW-C	278		278		278
75			PECO Com 303-LMR SW C	367		367		367
76			PECO Com 303-MO New Bus. Portal SW	21	21		$21	42
77			PECO Com 3030-Apollo SW	925		925		925
78			PECO Com 3030-BIDA Customer Project	130		130		130
79			PECO Com 3030-BIDA-AMI Ph2 SW	2,139		2,139		2,139
80			PECO Com 3030-CIS Transformation SW	120		120		120
81			PECO Com 3030-Cloud Serv 3 yr	2,577	436	2,142	$436	3,013
82			PECO Com 3030-Cloud Serv 4 yr	0	0		$0	0
83			PECO Com 3030-Cloud Serv 5 yr	4,385	1,858	2,527	$1,858	6,244
84			PECO Com 3030-Common MDM SW	228		228		228
85			PECO Com 3030-EU Digital Program We	2,817	230	2,587	$230	3,047
86			PECO Com 3030-EU oneMDS SW	5,240		5,240		5,240
87			PECO Com 3030-I Sign Up and Move	301	71	231	$71	372
88			PECO Com 3030-IT Cust Mobile App SW	127	6	121	$6	134
89			PECO Com 3030-IVR System PA	250	23	227	$23	272
90			PECO Com 3030-Misc 5 yr FR PA	7,970	1,830	6,140	$1,830	9,799
91			PECO Com 3030-Mobile Dispatch Mappi	5,842		5,842		5,842
92			PECO Com 3030-OBIEE Migration SW	275		275		275
93			Subtotal Common - Intangible Plant	$35,055	$5,402	$29,653	$5,402	$40,456
94								
95			PECO Gas 3913 PA					
96			Subtotal					
97								
98		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	$2,274	$752	$1,522	752	$3,026
99			PECO Gas 303-CC&B SW	3,281	53	3,228	53	3,334
100			PECO Gas 303-PECO RNI Upgrade SW G	177		177		177
101			PECO Gas 303-SES IV G SW	759		759		759
102			PECO Gas 3030-Cloud Serv 3 yr	10		10		10
103			PECO Gas 3030-Cloud Serv 5 yr	51		51		51
104			Subtotal Gas - Intangible Plant	$6,552	$805	$5,747	$805	$7,357
105								
106			Subtotal 404.0 Amort. Of Limited-Term Plant	$41,607	$6,207	$35,400	$6,207	$47,814
107								
108			Grand Total	$152,502	$13,237	$139,265	$13,237	$165,739

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
D-17 Depreciation Adjustment

				(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account	Plant Account	Depreciation Category	Utility Allocation Factor	Depr on Existing Assets + Adds (Utility)	Depr on Adds (Utility)	Depr on Existing Assets (Utility)	Annualize Current Yr Depr (Utility)	Pro Forma Test Yr Depr (Utility)
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	0.2302	$1,041		$1,041		$1,041
2			PECO Common 3902 IL	0.2302	4		4		4
3			PECO Common 3902 PA	0.2302	775	156	619	156	931
4			PECO Common 3903 PA	0.2302	71		71		71
5			PECO Common 3911 PA	0.2302	3		3		3
6			PECO Common 3912 PA	0.2302	524	9	515	9	534
7			PECO Common 3913 IL	0.2302	697	456	241	456	1,152
8			PECO Common 3913 PA	0.2302	1,727		1,727		1,727
9			PECO Common 3930 PA	0.2302	27	2	25	2	29
10			PECO Common 3941 PA	0.2302	0		0		0
11			PECO Common 3942 PA	0.2302	15	0	15	0	15
12			PECO Common 3970 PA	0.2302	1,369		1,369		1,369
13			PECO Common 3980 PA	0.2302	32		32		32
14			Subtotal Common - General Plant		$6,285	$623	$5,662	$623	$6,908
15									
16		Gas - Distribution	PECO Gas 3751 PA	1.0000	$229	$37	$193	$37	$266
17			PECO Gas 3752 PA	1.0000	77	11	66	11	88
18			PECO Gas 3753 PA	1.0000	146		146		146
19			PECO Gas 3761 PA	1.0000	11,902	603	11,299	603	12,505
20			PECO Gas 3762 PA	1.0000	1,363	106	1,258	106	1,469
21			PECO Gas 3763 PA	1.0000	23,747	1,406	22,341	1,406	25,152
22			PECO Gas 3780 PA	1.0000	594	58	537	58	652
23			PECO Gas 3790 PA	1.0000	1,045	65	980	65	1,110
24			PECO Gas 3801 PA	1.0000	3,793	47	3,746	47	3,841
25			PECO Gas 3802 PA	1.0000	21,653	894	20,759	894	22,547
26			PECO Gas 3810 PA	1.0000	2,199	72	2,127	72	2,271
27			PECO Gas 3811 PA	1.0000	3,534	67	3,467	67	3,600
28			PECO Gas 3820 PA	1.0000	5,287	326	4,961	326	5,612
29			PECO Gas 3870 PA	1.0000	123	20	102	20	143
30			Subtotal Gas - Distribution		$75,692	$3,711	$71,981	$3,711	$79,403
31									

($ in Thousands)

				(6)	(7)	(8)	(9)	(10)	(11)
Line No.	Account	Plant Account	Depreciation Category	Utility Allocation Factor	Depr on Existing Assets + Adds (Utility)	Depr on Adds (Utility)	Depr on Existing Assets (Utility)	Annualize Current Yr Depr (Utility)	Pro Forma Test Yr Depr (Utility)
32		Gas - General Plant	PECO Gas 3901 PA	1.0000	$98	$0	$98	$0	$99
33			PECO Gas 3902 PA	1.0000	55		55		55
34			PECO Gas 3903 PA	1.0000	70	0	70	0	70
35			PECO Gas 3911 PA	1.0000	0		0		0
36			PECO Gas 3912 PA	1.0000	41	1	40	1	42
37			PECO Gas 3913 IL	1.0000					
38			PECO Gas 3913 PA	1.0000	797	340	457	340	1,137
39			PECO Gas 3940 PA	1.0000	1,002	68	934	68	1,070
40			PECO Gas 3950 PA	1.0000	2		2		2
41			PECO Gas 3970 PA	1.0000	544	191	352	191	735
42			PECO Gas 3980 PA	1.0000	8		8		8
43			Subtotal Gas - General Plant		$2,617	$601	$2,016	$601	$3,219
44									
45		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$32		$32		$32
46			PECO Gas 3053 PA	1.0000					
47			PECO Gas 3110 PA	1.0000	151	3	148	3	154
48			Subtotal Gas - Production Plant		$183	$3	$181	$3	$186
49									
50		Gas - Storage	PECO Gas 3611 PA	1.0000	$46		$46		$46
51			PECO Gas 3612 PA	1.0000	293	0	292	0	293
52			PECO Gas 3613 PA	1.0000	20		20		20
53			PECO Gas 3620 PA	1.0000	9		9		9
54			PECO Gas 3630 PA	1.0000	22		22		22
55			PECO Gas 3631 PA	1.0000	141	0	141	0	142
56			PECO Gas 3632 PA	1.0000	2,878		2,878		2,878
57			PECO Gas 3633 PA	1.0000	771	7	765	7	778
58			PECO Gas 3634 PA	1.0000	525	0	525	0	525
59			PECO Gas 3635 PA	1.0000	394	1	393	1	395
60			Subtotal Gas - Storage		$5,100	$8	$5,092	$8	$5,108
61									
62			Subtotal 403.0 Depreciation Expense.		$89,877	$4,946	$84,931	$4,946	$94,824
63									

($ in Thousands)

Line No.	Account	Plant Account	Depreciation Category	(6) Utility Allocation Factor	(7) Depr on Existing Assets + Adds (Utility)	(8) Depr on Adds (Utility)	(9) Depr on Existing Assets (Utility)	(10) Annualize Current Yr Depr (Utility)	(11) Pro Forma Test Yr Depr (Utility)
64	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 303-CFP B&P SW	0.2302	$16	$16		$16	$32
65			PECO Com 303-CFP MEU SW	0.2302	$31		$31		$31
66			PECO Com 303-CFP MMA SW	0.2302	$9	$9		$9	$18
67			PECO Com 303-DSS Platform Enhanc SW	0.2302	$15	$15		$15	$31
68			PECO Com 303-EU Custom Hardening SW	0.2302	$20	$20		$20	$39
69			PECO Com 303-EU EAM SW	0.2302	$14	$14		$14	$27
70			PECO Com 303-EU EAM Transformation	0.2302	$5	$5		$5	$10
71			PECO Com 303-EU GIS Core SW	0.2302	$129	$129		$129	$258
72			PECO Com 303-EU Reliab-Auto SW	0.2302	$3	$3		$3	$5
73			PECO Com 303-Grid FR Workstream SW	0.2302	$3	$3		$3	$6
74			PECO Com 303-IGA Enhance Prog SW-C	0.2302	$64		$64		$64
75			PECO Com 303-LMR SW C	0.2302	$85		$85		$85
76			PECO Com 303-MO New Bus. Portal SW	0.2302	$5	$5		$5	$10
77			PECO Com 3030-Apollo SW	0.2302	$213		$213		$213
78			PECO Com 3030-BIDA Customer Project	0.2302	$30		$30		$30
79			PECO Com 3030-BIDA-AMI Ph2 SW	0.2302	$492		$492		$492
80			PECO Com 3030-CIS Transformation SW	0.2302	$28		$28		$28
81			PECO Com 3030-Cloud Serv 3 yr	0.2302	$593	$100	$493	$100	$694
82			PECO Com 3030-Cloud Serv 4 yr	0.2302	$0	$0		$0	$0
83			PECO Com 3030-Cloud Serv 5 yr	0.2302	$1,010	$428	$582	$428	$1,437
84			PECO Com 3030-Common MDM SW	0.2302	$53		$53		$53
85			PECO Com 3030-EU Digital Program We	0.2302	$648	$53	$595	$53	$701
86			PECO Com 3030-EU oneMDS SW	0.2302	$1,206		$1,206		$1,206
87			PECO Com 3030-I Sign Up and Move	0.2302	$69	$16	$53	$16	$86
88			PECO Com 3030-IT Cust Mobile App SW	0.2302	$29	$1	$28	$1	$31
89			PECO Com 3030-IVR System PA	0.2302	$57	$5	$52	$5	$63
90			PECO Com 3030-Misc 5 yr FR PA	0.2302	$1,835	$421	$1,413	$421	$2,256
91			PECO Com 3030-Mobile Dispatch Mappi	0.2302	$1,345		$1,345		$1,345
92			PECO Com 3030-OBIEE Migration SW	0.2302	$63		$63		$63
93			Subtotal Common - Intangible Plant		$8,070	$1,243	$6,826	$1,243	$9,313
94									
95			PECO Gas 3913 PA	1.0000					
96			Subtotal						
97									
98		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$2,274	$752	$1,522	$752	$3,026
99			PECO Gas 303-CC&B SW	1.0000	3,281	53	3,228	53	3,334
100			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	177		177		177
101			PECO Gas 303-SES IV G SW	1.0000	759		759		759
102			PECO Gas 3030-Cloud Serv 3 yr	1.0000	10		10		10
103			PECO Gas 3030-Cloud Serv 5 yr	1.0000	51		51		51
104			Subtotal Gas - Intangible Plant		$6,552	$805	$5,747	$805	$7,357
105									
106			Subtotal 404.0 Amort. Of Limited-Term Plant		$14,622	$2,049	$12,573	$2,049	$16,670
107									
108			Grand Total		$104,499	$6,995	$97,504	$6,995	$111,494

($ in Thousands)

				(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Account	Plant Account	Depreciation Category	Functional Allocation Factor	Depr on Existing Assets + Adds (Function)	Depr on Adds (Function)	Depr on Existing Assets (Function)	Annualize Current Yr Depr (Function)	Pro Forma Test Yr Depr (Function)
1	403.0 Depreciation Expense.	Common-General Plant	PECO Common 3901 PA	1.0000	$1,041		$1,041		$1,041
2			PECO Common 3902 IL	1.0000	4		4		4
3			PECO Common 3902 PA	1.0000	775	156	619	156	931
4			PECO Common 3903 PA	1.0000	71		71		71
5			PECO Common 3911 PA	1.0000	3		3		3
6			PECO Common 3912 PA	1.0000	524	9	515	9	534
7			PECO Common 3913 IL	1.0000	697	456	241	456	1,152
8			PECO Common 3913 PA	1.0000	1,727		1,727		1,727
9			PECO Common 3930 PA	1.0000	27	2	25	2	29
10			PECO Common 3941 PA	1.0000	0		0		0
11			PECO Common 3942 PA	1.0000	15	0	15	0	15
12			PECO Common 3970 PA	1.0000	1,369		1,369		1,369
13			PECO Common 3980 PA	1.0000	32		32		32
14			Subtotal Common - General Plant		$6,285	$623	$5,662	$623	$6,908
15									
16		Gas - Distribution	PECO Gas 3751 PA	1.0000	$229	$37	$193	$37	$266
17			PECO Gas 3752 PA	1.0000	77	11	66	11	88
18			PECO Gas 3753 PA	1.0000	146		146		146
19			PECO Gas 3761 PA	1.0000	11,902	603	11,299	603	12,505
20			PECO Gas 3762 PA	1.0000	1,363	106	1,258	106	1,469
21			PECO Gas 3763 PA	1.0000	23,747	1,406	22,341	1,406	25,152
22			PECO Gas 3780 PA	1.0000	594	58	537	58	652
23			PECO Gas 3790 PA	1.0000	1,045	65	980	65	1,110
24			PECO Gas 3801 PA	1.0000	3,793	47	3,746	47	3,841
25			PECO Gas 3802 PA	1.0000	21,653	894	20,759	894	22,547
26			PECO Gas 3810 PA	1.0000	2,199	72	2,127	72	2,271
27			PECO Gas 3811 PA	1.0000	3,534	67	3,467	67	3,600
28			PECO Gas 3820 PA	1.0000	5,287	326	4,961	326	5,612
29			PECO Gas 3870 PA	1.0000	123	20	102	20	143
30			Subtotal Gas - Distribution		$75,692	$3,711	$71,981	$3,711	$79,403
31									

($ in Thousands)

				(12)	(13)	(14)	(15)	(16)	(17)
Line No.	Account	Plant Account	Depreciation Category	Functional Allocation Factor	Depr on Existing Assets + Adds (Function)	Depr on Adds (Function)	Depr on Existing Assets (Function)	Annualize Current Yr Depr (Function)	Pro Forma Test Yr Depr (Function)
32		Gas - General Plant	PECO Gas 3901 PA	1.0000	$98	$0	$98	$0	$99
33			PECO Gas 3902 PA	1.0000	55		55		55
34			PECO Gas 3903 PA	1.0000	70	0	70	0	70
35			PECO Gas 3911 PA	1.0000	0		0		0
36			PECO Gas 3912 PA	1.0000	41	1	40	1	42
37			PECO Gas 3913 IL	1.0000					
38			PECO Gas 3913 PA	1.0000	797	340	457	340	1,137
39			PECO Gas 3940 PA	1.0000	1,002	68	934	68	1,070
40			PECO Gas 3950 PA	1.0000	2		2		2
41			PECO Gas 3970 PA	1.0000	544	191	352	191	735
42			PECO Gas 3980 PA	1.0000	8		8		8
43			Subtotal Gas - General Plant		$2,617	$601	$2,016	$601	$3,219
44									
45		Gas - Production Plant	PECO Gas 3050 PA	1.0000	$32		$32		$32
46			PECO Gas 3053 PA	1.0000					
47			PECO Gas 3110 PA	1.0000	151	3	148	3	154
48			Subtotal Gas - Production Plant		$183	$3	$181	$3	$186
49									
50		Gas - Storage	PECO Gas 3611 PA	1.0000	$46		$46		$46
51			PECO Gas 3612 PA	1.0000	293	0	292	0	293
52			PECO Gas 3613 PA	1.0000	20		20		20
53			PECO Gas 3620 PA	1.0000	9		9		9
54			PECO Gas 3630 PA	1.0000	22		22		22
55			PECO Gas 3631 PA	1.0000	141	0	141	0	142
56			PECO Gas 3632 PA	1.0000	2,878		2,878		2,878
57			PECO Gas 3633 PA	1.0000	771	7	765	7	778
58			PECO Gas 3634 PA	1.0000	525	0	525	0	525
59			PECO Gas 3635 PA	1.0000	394	1	393	1	395
60			Subtotal Gas - Storage		$5,100	$8	$5,092	$8	$5,108
61									
62			Subtotal 403.0 Depreciation Expense.		$89,877	$4,946	$84,931	$4,946	$94,824
63									

($ in Thousands)

Line No.	Account	Plant Account	Depreciation Category	(12) Functional Allocation Factor	(13) Depr on Existing Assets + Adds (Function)	(14) Depr on Adds (Function)	(15) Depr on Existing Assets (Function)	(16) Annualize Current Yr Depr (Function)	(17) Pro Forma Test Yr Depr (Function)
64	404.0 Amort. Of Limited-Term Intangible Plant.	Common - Intangible Plant	PECO Com 303-CFP B&P SW	1.0000	$16	$16		$16	$32
65			PECO Com 303-CFP MEU SW	1.0000	$31		$31		$31
66			PECO Com 303-CFP MMA SW	1.0000	$9	$9		$9	$18
67			PECO Com 303-DSS Platform Enhanc SW	1.0000	$15	$15		$15	$31
68			PECO Com 303-EU Custom Hardening SW	1.0000	$20	$20		$20	$39
69			PECO Com 303-EU EAM SW	1.0000	$14	$14		$14	$27
70			PECO Com 303-EU EAM Transformation	1.0000	$5	$5		$5	$10
71			PECO Com 303-EU GIS Core SW	1.0000	$129	$129		$129	$258
72			PECO Com 303-EU Reliab-Auto SW	1.0000	$3	$3		$3	$5
73			PECO Com 303-Grid FR Workstream SW	1.0000	$3	$3		$3	$6
74			PECO Com 303-IGA Enhance Prog SW-C	1.0000	$64		$64		$64
75			PECO Com 303-LMR SW C	1.0000	$85		$85		$85
76			PECO Com 303-MO New Bus. Portal SW	1.0000	$5	$5		$5	$10
77			PECO Com 3030-Apollo SW	1.0000	$213		$213		$213
78			PECO Com 3030-BIDA Customer Project	1.0000	$30		$30		$30
79			PECO Com 3030-BIDA-AMI Ph2 SW	1.0000	$492		$492		$492
80			PECO Com 3030-CIS Transformation SW	1.0000	$28		$28		$28
81			PECO Com 3030-Cloud Serv 3 yr	1.0000	$593	$100	$493	$100	$694
82			PECO Com 3030-Cloud Serv 4 yr	1.0000	$0	$0		$0	$0
83			PECO Com 3030-Cloud Serv 5 yr	1.0000	$1,010	$428	$582	$428	$1,437
84			PECO Com 3030-Common MDM SW	1.0000	$53		$53		$53
85			PECO Com 3030-EU Digital Program We	1.0000	$648	$53	$595	$53	$701
86			PECO Com 3030-EU oneMDS SW	1.0000	$1,206		$1,206		$1,206
87			PECO Com 3030-I Sign Up and Move	1.0000	$69	$16	$53	$16	$86
88			PECO Com 3030-IT Cust Mobile App SW	1.0000	$29	$1	$28	$1	$31
89			PECO Com 3030-IVR System PA	1.0000	$57	$5	$52	$5	$63
90			PECO Com 3030-Misc 5 yr FR PA	1.0000	$1,835	$421	$1,413	$421	$2,256
91			PECO Com 3030-Mobile Dispatch Mappi	1.0000	$1,345		$1,345		$1,345
92			PECO Com 3030-OBIEE Migration SW	1.0000	$63		$63		$63
93			Subtotal Common - Intangible Plant		$8,070	$1,243	$6,826	$1,243	$9,313
94									
95			PECO Gas 3913 PA	1.0000					
96			Subtotal						
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98		Gas - Intangible Plant	PECO Gas 303 Misc 5 YR FR PA	1.0000	$2,274	$752	$1,522	$752	$3,026
99			PECO Gas 303-CC&B SW	1.0000	3,281	53	3,228	53	3,334
100			PECO Gas 303-PECO RNI Upgrade SW G	1.0000	177		177		177
101			PECO Gas 303-SES IV G SW	1.0000	759		759		759
102			PECO Gas 3030-Cloud Serv 3 yr	1.0000	10		10		10
103			PECO Gas 3030-Cloud Serv 5 yr	1.0000	51		51		51
104			Subtotal Gas - Intangible Plant		$6,552	$805	$5,747	$805	$7,357
105									
106			Subtotal 404.0 Amort. Of Limited-Term Plant		$14,622	$2,049	$12,573	$2,049	$16,670
107									
108			Grand Total		$104,499	$6,995	$97,504	$6,995	$111,494

($ in Thousands)

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
1	Revenue		$864,053	$16,153	$880,205
2	Operating Expenses		579,269	157	579,426
3	OIBIT	L1 - L2	$284,784	$15,996	$300,779
4					
5	Rate Base		$3,546,125		$3,546,125
6	Weighted Cost of Debt		2.620%		2.620%
7	Synchronized Interest Expense	L5 * L6	$92,908		$92,908
8	Base Taxable Income	L3 - L7	$191,875	$15,996	$207,871
9					
10	State Accelerated Tax Depreciation		$87,086		$87,086
11	Pro Forma Book Depreciation		111,494		111,494
12	State Tax Depreciation (Over) Under Book	L11 - L10	$24,408		$24,408
13	Regulatory Asset Programs M-1, Pension & Post-Retirement & Other		1,838		1,838
14	Other Property Basis Adjustments (CIAC/ICM)		(17,222)		(17,222)
15	Removal Costs/Software		(5,034)		(5,034)
16	AFUDC Equity		(11,744)		(11,744)
17	Permanent Adjustments		584		584
18	Repair Deduction		(211,930)		(211,930)
19					
20	State Taxable Income	L8 + Sum L12 toL18	($27,224)	$15,996	($11,229)
21					
22	State Income Tax Rate		7.99%	7.99%	7.99%
23	State Income Tax Benefit / (Expense) before Net Operating Loss	- (L20 * L22)	$2,175	($1,278)	$897
24	Net Operating Loss Utilization %		40.00%	40.00%	100.00%
25	Net Operating Loss Utilization	- (L24 * L23)	(870)	511	(359)
26	State Income Tax Benefit / (Expense)	L23 + L25	$1,305	($767)	$538
27					
28	Federal Accelerated Tax Depreciation		$83,227		$83,227
29	Pro Forma Book Depreciation		111,494		111,494
30	Federal Tax Deducts (Over) Under Book	L29 - L28	$28,267		$28,267
31	Regulatory Asset Programs M-1, Pension & Post-Retirement		1,838		1,838
32	Other Property Basis Adjustments (CIAC/ICM)		(17,222)		(17,222)
33	Removal Costs/Software		(5,034)		(5,034)
34	AFUDC Equity		(11,744)		(11,744)
35	Permanent Adjustments		584		584
36	Repair Deduction		(211,930)		(211,930)
37	Federal NOL				
38	Federal Taxable Income	L8 - L26 + Sum L30 to L37	($22,060)	$15,229	($6,831)
39					
40	Federal Income Tax Rate %		21.00%	21.00%	21.00%
41	Federal Income Tax Benefit / (Expense) before Deferred and Adjustments	- (L38 * L40)	$4,633	($3,198)	$1,435
42	Corporate Alternative Minimum Tax				
43	Total Tax Benefit / (Expense) before Deferred Income Tax	L26 + L41 + L42	$5,938	($3,965)	$1,973
44					

($ in Thousands)

Line No.	Description	Reference	(1) Present Rates	(2) Rate Increase	(3) Proposed Rates
45	**DEFERRED INCOME TAXES**				
46	Deferred Taxes on Timing Differences- Federal		$1,724	$107	$1,831
47	Deferred Taxes on Timing Differences- State		(1,229)		(1,229)
48	Deferred Taxes on State NOL		870	(511)	359
49	Excess Deferred Amortization		3,468		3,468
50	Excess Deferred Amortization - State (Net of Federal)		271		271
51	Deferred Taxes on Federal NOL				
52	Federal Income Tax on Flow Through Adjustments		(6,736)		(6,736)
53	Corporate Alternative Minimum Tax				
54	Deferred Income Taxes Benefit / (Expense)	SUM L46 to L53	($1,632)	($404)	($2,036)
55					
56	Net Income Tax Benefit / (Expense)	L43 + L54	$4,305	($4,369)	($63)
57					
58	**Other Income Tax Adjustments**				
59	Amortization of Investment Tax Credit		($5)		($5)
60					
61	Combined Income Tax Benefit / (Expense)	L56 + L59	$4,301	($4,369)	($68)
62					
63	Federal Income Tax Benefit / (Expense)	L41 + L46 + L49 + L51 + L52 + L59	$3,084	($3,091)	($7)
64	State Income Tax Benefit / (Expense)	L26 + L47+ L48 + L50	$1,217	($1,278)	($61)
65	Total Income Tax Benefit / (Expense)	L63 + L64	**$4,301**	**($4,369)**	**($68)**

PECO Gas Operations
Before The Pennsylvania Public Utility Commission
HTY Ending December 2025
($ in Thousands)
D-19 Conversion Factor

Line No.	Description	(1) Reference	(2) Utility
1	**GROSS REVENUE CONVERSION FACTOR**		
2	GROSS REVENUE FACTOR		1.000000
3	Forfeited Discounts Amount		2,457
4	Total Customer Revenue		835,990
5	Shopping Revenue		89,762
6	LPC REVENUE	L3 / (L4 + L5)	0.002654
7	GROSS RECEIPTS TAX		
8	UNCOLLECTIBLE EXPENSES		(0.005231)
9	PUC / OCA & SBA ASSESSMENT AS A % OF REVENUE		(0.004505)
10			
11			
12	NET REVENUES	L2 + L6 + L7 + L8 + L9	0.992918
13			
14	STATE INCOME TAX RATE		7.990%
15			
16	STATE INCOME TAX FACTOR	- L12 * L14	(0.079334)
17			
18	FACTOR AFTER STATE TAXES	L12 + L16	0.913584
19			
20	FEDERAL INCOME TAX RATE		21.000%
21			
22	FEDERAL INCOME TAX FACTOR	- L18 * L20	(0.191853)
23			
24			
25	NET OPERATING INCOME FACTOR	L18 + L22	0.721732
26			
27	GROSS REVENUE CONVERSION FACTOR	1 / L25	1.385557
28			
29	Combined Income Tax Factor on Gross Revenues	- L16 - L22	27.119%
30			
31			
32	**INCOME TAX FACTOR**		
33			
34	GROSS REVENUE FACTOR	L2	1.000000
35			
36	STATE INCOME TAX RATE		7.990%
37			
38	STATE INCOME TAX FACTOR	- L34 * L36	(0.079900)
39			
40			
41	FACTOR AFTER STATE TAXES	L34 + L38	0.920100
42			
43	FEDERAL INCOME TAX RATE		21.000%
44			
45	FEDERAL INCOME TAX FACTOR	- L41 * L43	(0.193221)
46			
47	NET OPERATING INCOME FACTOR	L41 + L45	0.726879
48			
49			
50	GROSS REVENUE CONVERSION FACTOR	1 / L47	1.375745
51			
52			
53	Combined Income Tax Factor On Taxable Income	L34 - L47	27.312%

PECO Statement No. 5:
Direct Testimony of John Coursey

PECO ENERGY COMPANY
STATEMENT NO. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
v.
PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2026-3060860

DIRECT TESTIMONY

WITNESS: JOHN COURSEY

SUBJECT: GAS SALES FORECAST

DATED: MARCH 30, 2026

TABLE OF CONTENTS

Page

DIRECT TESTIMONY
OF
JOHN COURSEY

I. INTRODUCTION AND PURPOSE OF TESTIMONY

1. Q. Please state your full name and business address.

A. My name is John Coursey. My business address is 2301 Market Street, Philadelphia, Pennsylvania 19103.

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

A. I am employed by Exelon Corporation ("Exelon") as a Load Forecast Analysis Manager. In that capacity, I am responsible for developing and maintaining a series of forecasts pertaining mainly to electric and gas sales and customers for PECO Energy Company ("PECO" or the "Company"). I also work closely with the entire Exelon Load Forecasting team, helping to oversee, prepare, and evaluate numerous billing determinants forecasts.

3. Q. Please briefly describe your educational background and professional experience.

A. I hold a Bachelor of Business Administration in Management from James Madison University. I have worked for Exelon since 2007, initially as a consultant and then as an employee beginning in 2009. During that time, I have held numerous load forecasting and analysis related roles under Exelon or its subsidiary, PECO. My positions while working at Exelon have included (in chronological order): Senior Business Analyst for PECO's Demand Response (DR) team in the Marketing Department; Senior Load Forecasting Analyst for PECO's Finance Department; Senior Energy Acquisition Analyst in PECO's Energy Acquisition Department;

and my current position as Load Forecasting Analysis Manager for Exelon, which I assumed in June 2019. My current responsibilities primarily include billing determinants forecasting (sales, customers, demand), load data analysis, forecast variance analysis and tracking, weather normalization of sales, and electric peak forecasting. I have nearly 20 years of utility experience covering electric and gas sales forecasting, electric billed demand forecasting, electric peak demand forecasting, short-term hourly electric load forecasting, PJM Interconnection LLC (PJM) Settlement and Peak Load Contribution (PLC) calculation, and DR measurement and evaluation.

I have not previously testified before the Pennsylvania Public Utility Commission, but I have supported PECO in numerous past electric and gas rate cases, and have also served as a billing determinants forecast witness twice before the Maryland Public Service Commission on behalf of Pepco (see Case No. 9702 (filed in 2023) and Case No. 9820 (filed in 2025)).

4. Q. What is the purpose of your direct testimony?

A. The purpose of my direct testimony is to describe PECO's gas sales forecast.

II. GAS SALES FORECAST

5. Q. How does PECO develop its gas sales forecast, generally?

A. The natural gas forecasting process uses multiple regression-analysis models that determine the relationship between monthly gas sales and predictive variables, such as weather, economic indicators, usage trends, and time of year. The modeled results are evaluated using standard statistical criteria (e.g., the Adjusted R-Squared Score, Mean Absolute Percentage Error, t-statistics, and coefficients) to ensure that there are statistically significant relationships between the dependent and independent variables. Further detail is provided in the Company's responses to Commission filing requirements SDR-RR-9 and SDR-RR-10.

6. Q. How does PECO utilize historical weather data in developing its gas sales forecasts?

A. PECO's gas forecasts utilize "weather normal" assumptions based on 30-year weather averages. Use of a 30-year weather normal period is consistent with the National Oceanic and Atmospheric Administration's definition of "normal" weather and the Company believes that the use of a longer 30-year historical period reduces forecast volatility. PECO's weather normal assumptions are re-calculated annually using the latest 30-year period available at the time of the update. The Company also utilizes weather normal assumptions to normalize historical sales results. The Company then analyzes the temperature-normalized historical usage to discern customer usage trends that result from factors other than weather. Out-of-Model adjustments are then made, where needed, to the modeled forecasts to remain consistent with these trends and address any new growth drivers expected to impact future sales. The results of the forecast are then compared to prior forecasts for consistency and reviewed with the Exelon Senior Manager of Load Forecasting, the PECO Director of Financial Planning and Business Analysis, and senior management for their approval.

7. Q. Are you familiar with the Commission's recent Opinion and Order in the 2025 base rate case of Columbia Gas of Pa., Inc. ("Columbia Gas")[1]?

A. Yes.

[1] *See Pa. P.U.C. v. Columbia Gas of Pa., Inc.*, Docket No. R-2025-3053499 (Order entered Dec. 9, 2025) ("Columbia Order").

8. Q. Did the Commission address the use of a weather normal period in the context of evaluating Columbia Gas' weather normalization adjustment ("WNA")?

A. Yes. The Commission agreed with a proposal to modify Columbia Gas' weather normal period from twenty years to ten years.[2]

9. Q. How has PECO reflected the Commission's decision in the Columbia Order in its WNA proposal?

A. As discussed in the direct testimony of PECO witness John Taylor (PECO Statement No. 6), PECO is utilizing a 10-year weather normal period for normalizing billing determinants and the WNA.

To align the Company's projected sales analysis, which was performed utilizing a 30-year historical period (1994 to 2023) consistent with Exelon's longstanding forecasting practice, with the Commission's preference for utilization of a 10-year weather normal period, the Company is proposing a pro forma adjustment to its FPFTY revenues to reflect forecasted sales under a 10-year weather normal scenario (2015 to 2024). The revenue adjustment related to this sales forecast update is reflected in the direct testimony of Company witness Michael Trzaska (PECO Statement No. 4) and shown in PECO Exhibit MJT-1, Schedule D-5F. As noted by Mr. Taylor, this is important to align the Company's revenue requirement and billing determinants within the same period when setting rates.

[2] Columbia Order, p. 302.

10. Q. How did the Company develop this adjustment?

A. The Company re-ran its econometric sales models using 10-year weather normal assumptions, resulting in revised sales and revenue forecasts. The proposed sales and revenue adjustment equals the total difference between revenues forecast under the 30-year and 10-year weather normal scenarios. Applying this adjustment brings the weather assumptions underlying the Company's FPFTY revenues into closer alignment with those that would be reflected through the Company's proposed WNA. This is discussed further by Mr. Taylor.

11. Q. What is the economic outlook for the PECO service territory and how does this impact your sales growth expectations?

A. S&P Global, an external vendor that provides economic data to the Company, projects that between 2025, the FPFTY in the Company's prior base rate case, and 2027, the FPFTY in this case, the Philadelphia region's annual growth in gross metropolitan product and employment will be 2.3% and 0.4%, respectively, slowing to 1.8% and 0.2%, respectively, during the FPFTY,[3] driven by federal policy actions, including tariff and immigration policy. Employment growth supported by the region's healthcare industry supported customer growth in 2025. S&P Global expects this trend to continue but the overall pace to slow as the federal policy impacts from 2025 slow broader employment growth. This economic outlook is one of several drivers impacting the Company's forecasts.

[3] Data from S&P Global for Philadelphia, PA categorized under "Metropolitan level" as of August 2025.

12. Q. Please describe the results of the Company's sales forecast.

A. Between 2025 and the end of 2027, the Company forecasts total weather normal gas sales to grow 0.3% annually, with 0.1% annual growth in Residential sales and 0.4% annual growth in Commercial & Industrial sales. Sales will primarily be driven by customer growth and economic growth.

Over the same period, the number of PECO customers is forecasted to grow by 0.4% per year, with 0.5% annual growth in Residential customers and 0.2% annual growth in Commercial & Industrial customers. Based on the Company's sales and customer forecasts detailed above, use per customer ("UPC") during that same period is forecasted to decline by -0.2% per year, with -0.3% annual decline in residential UPC and 0.2% annual increase in Commercial & Industrial UPC.

III. CONCLUSION

13. Q. Does this complete your direct testimony at this time?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**DOCKET NO. R-2026-3060860**
	:	
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, John Coursey, hereby state that I am a Load Forecast Analysis Manager at Exelon; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 5 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Dated: March 30, 2026

John Coursey

PECO Statement No. 6:
Direct Testimony of John Taylor

PECO ENERGY STATEMENT NO. 6

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION

v.

PECO ENERGY COMPANY – GAS DIVISION

DOCKET NO. R-2026-3060860

DIRECT TESTIMONY

WITNESS: JOHN TAYLOR

SUBJECT: WEATHER NORMALIZATION
ADJUSTMENT

DATED: March 30, 2026

Table of Contents

Glossary of Acronyms

Acronym	Description
AHDD	Actual Heating Degree Days
AMC	Actual Monthly Mcfs
Atrium	Atrium Economics, LLC
BLMC	Base Load Monthly Mcfs
CAP-PIPP	Customer Assistance Program – Percentage of Income Payment Plan
Commission	Pennsylvania Public Utility Commission
FAQs	Frequently Asked Questions
FERC	Federal Energy Regulatory Commission
GRC	General Rate Case
HDD	Heating Degree Days
NHDD	Normal Heating Degree Days
NOAA	National Oceanic and Atmospheric Administration
PECO	PECO Energy Company – Gas Division
Rate GR	Rate GR General Service - Residential
Rate GC	Rate GC General Service - Commercial and Industrial
SFV	Straight-Fixed-Variable
WNA	Weather Normalization Adjustment
WNAC	Weather Normalized Adjustment Mcfs
WNBC	Weather Normalized Billing Mcfs

DIRECT TESTIMONY
OF
JOHN TAYLOR

I. INTRODUCTION

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

A. My name is John Taylor, and I am employed by Atrium Economics, LLC ("Atrium Economics" or "Atrium") as a Managing Partner. My business address is 10 Hospital Center Commons, Suite 400, Hilton Head Island, SC 29926. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

2. Q. On whose behalf are you testifying?

A. I am testifying on behalf of PECO Energy Company – Gas Division ("PECO" or the "Company").

3. Q. Mr. Taylor, have you previously testified before the Pennsylvania Public Utility Commission ("Commission") or any other regulatory authority?

A. Yes. I have presented expert testimony before the Federal Energy Regulatory Commission ("FERC") and numerous state and provincial regulatory commissions, including the Commission.

4. Q. What is the purpose of your direct testimony?

A. I am testifying in support of PECO's request to implement a Weather Normalization Adjustment ("WNA") mechanism.

5. Q. What Exhibits are you sponsoring in this proceeding?

A. I am sponsoring Exhibit JDT-1, WNA Proposal Policy Factors, and Exhibit JDT-2, WNA Calculation Example.

6. Q. Please state whether the Company has previously proposed a WNA mechanism.

A. Yes, PECO requested approval to implement a WNA in its prior base rate case ("2024 GRC").

7. Q. Does the Company's WNA request in this case differ from its WNA request in the 2024 GRC?

A. Yes. As explained in detail below, the WNA PECO is proposing in this case differs from the WNA proposed by PECO in the 2024 GRC in several key areas. For example, the Company is (1) adopting a 10-year weather period for normalizing billing determinants and the WNA, (2) proposing a 5% "deadband" to determine applicability of the WNA, (3) committing to ongoing and comprehensive reporting to the Commission, and (4) excluding the month of May so that the WNA will only be applied in October through April. PECO made these changes in an effort to enhance customer protections and align with recent Commission precedent.

II. PECO'S WNA MECHANISM PROPOSAL

8. Q. Can you explain the purpose of PECO's proposed WNA mechanism?

A. PECO is proposing a WNA to adjust the delivery portion of customer bills to reflect normal weather rather than actual weather conditions. This mechanism aims to mitigate the impact of unusual weather on customer bills during the heating season while giving the Company a fair opportunity to recover its authorized revenue requirement.

9. Q. Why is a WNA mechanism necessary for PECO's rate structure?

A. PECO's current rate design recovers a significant portion of its fixed costs through volumetric charges. As a result, changes in typical customer usage driven by unusual weather can cause PECO to under-recover fixed distribution costs in warmer than normal winters and over-recover fixed distribution costs in colder than normal winters. The WNA provides stability in cost recovery by providing the Company a reasonable opportunity to recover its authorized revenue requirement while protecting customers from over-recovery of PECO's fixed costs relative to normal weather.

10. Q. Can you elaborate on the relationship between fixed costs and usage-based recovery in PECO's current rate design?

A. PECO's current rate design recovers a significant portion of its fixed costs, such as infrastructure, maintenance, and administrative expenses, through volumetric charges based on customer usage. This means that when weather is warmer than normal and gas consumption declines, PECO under-recovers those fixed costs, even though they do not vary with usage.[1] Conversely, colder-than-normal weather can lead to over-recovery of these fixed costs. This mismatch creates volatility for both customers and the utility. The WNA mechanism helps address this financial volatility by normalizing the Company's revenues to reflect normal weather conditions, ensuring that fixed costs are recovered consistent with the recovery authorized by the Commission.

11. Q. What portion of PECO's fixed costs is recovered through its current volumetric distribution charges?

A. As shown on PECO Exhibit JAB-3 – Proof of Revenues at Present and Proposed Rates, at proposed rates, approximately 72% of distribution revenues for Rate GR General Service - Residential ("Rate GR") is recovered through the volumetric

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[1] 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; however, their recovery is highly dependent on temperature and the volumes of usage consumed.

distribution charge. For Rate GC General Service - Commercial and Industrial ("Rate GC"), approximately 85% of distribution revenue is recovered through the volumetric distribution charge. Distribution revenues primarily reflect fixed costs associated with the Company's delivery infrastructure and related operations. Accordingly, this percentage reflects the portion of fixed costs that are currently recovered on a usage-sensitive basis.

12. Q. Can you explain how recent weather trends have affected customer bills and PECO's ability to recover authorized revenues?

A. Recent weather trends have been characterized by greater variability, including a general pattern of milder winters over time as well as periods of severely colder-than-normal weather. Because PECO's current rate design recovers a significant portion of its fixed distribution costs through usage-based charges, deviations from normal weather directly affect customer bills and the Company's ability to recover its authorized revenue requirement. During milder-than-normal winters, reduced natural gas consumption results in lower customer bills and under-recovery of authorized revenues because PECO's fixed costs do not decline with reductions in usage. Conversely, during colder-than-normal winters, increased natural gas consumption can produce higher bills for customers and an over-recovery of authorized revenues relative to the level of fixed distribution costs embedded in rates.

For example, this winter in Pennsylvania has been colder than normal, and gas utilities in the Commonwealth with WNAs are issuing credits to customers to adjust for the fact that revenues are being collected in excess of the Commission-authorized revenues associated with normal-weather levels. This demonstrates that a WNA operates symmetrically, protecting customers in colder-than-normal periods and stabilizing utility recovery during milder periods. If PECO had a WNA in place this winter, its customers would have received such credits as well.

Absent such a mechanism, PECO and its customers remain exposed to weather-driven revenue volatility in either direction. As weather patterns become more variable, that volatility increases, underscoring the value of a mechanism that aligns customer bills and revenue recovery with normal weather assumptions embedded in Commission-approved rates.

13. Q. How is normal weather typically defined by the industry?

A. Typically, normal weather is defined as the average weather conditions over a specified historical period. The number of years used to calculate the average varies by utility and jurisdiction but usually is within the range of 10 to 30 years of historic weather data. Depending on the use case (e.g. demand forecasting or energy forecasting) different types of averages are used (simple versus rank & mean).

14. Q. How are weather-normalized gas volumes used to derive a gas utility's base rates?

A. As part of the rate design in a base rate proceeding, a utility's volumetric unit rates for gas service are derived by dividing the costs to be recovered through volumetric based rates by the anticipated weather-normalized gas sales volumes. These rates are designed to provide the utility with an opportunity to recover the costs it incurs to provide utility service, at the levels determined in the utility's rate case under normal weather conditions. To the extent any costs are subject to recovery in a volumetric charge, the recovery of such amounts is entirely dependent upon the volumes of gas usage experienced by the utility. Therefore, the recovery of costs in a volumetric component of rates will always lead to a difference in recovery of actual costs because actual weather conditions will never match the normalized weather conditions used to set rates.

15. Q. How does the methodology to define normal weather contribute to the calculation of WNA adjustments?

A. The choice of normalization period directly impacts the baseline against which actual usage is compared in the WNA mechanism. Reliance on historical averages to define normal weather introduces a variable in the calculation of the WNA adjustments, particularly when those averages may not fully reflect current or emerging weather trends. In prior rate cases, the Company used a long-term Heating Degree Day ("HDD")[2] average of 30 years of data from the National Oceanic and Atmospheric Administration ("NOAA") to establish a baseline for adjustments. Assuming the warming trend continues, a shorter period for normalization may reduce the difference between normal and actual HDD, as shown in Figure 1 below.

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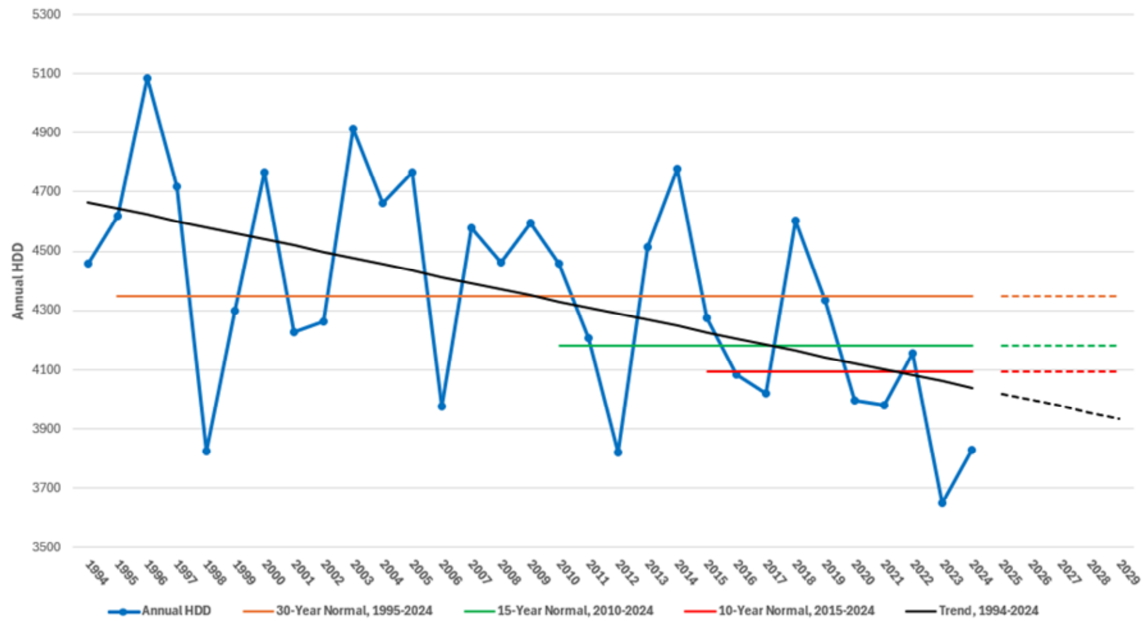
[2] Heating Degree Days are a weather metric used to estimate space-heating demand. HDD are calculated by subtracting the average daily temperature from a specified base temperature (commonly 65°F) whenever the average temperature is below that base. HDD are aggregated over a billing period and are frequently used in statistical analyses and normalization methodologies to isolate the effect of weather on gas consumption.

Figure 1 – Historic Annual HDD and Normalization Alternatives



16. Q. What is PECO proposing to address the variability introduced by the weather normalization methodology?

A. PECO is proposing to use a 10-year average of HDD for the normalization of billing determinants. By using a 10-year average, reflecting recent warmer weather, the normalized billing determinants will be lower than those derived from using a 30-year average that includes more colder than average years. Assuming the warming trend continues, actual usage may be closer to, or even below, the 10-year baseline, triggering a smaller WNA surcharge or credit. However, no one (PECO included) can predict the number of HDDs in any given year with certainty; therefore, variations are still expected, and the WNA would still provide value to both customers and the Company. Furthermore, the normalization period used to set rates and the normalization baseline used in the WNA will be consistent under PECO's proposal. Maintaining a consistent HDD baseline for both functions aligns with the overarching utility ratemaking "matching principle," which requires that the utility align revenue requirements and billing determinants within the same period and under the same assumptions when setting rates.[3]

17. Q. Apart from a WNA, are there other rate design approaches that could reduce weather-related customer bills and revenue volatility?

A. Yes. A Straight-Fixed-Variable ("SFV") rate design could reduce weather sensitivity by recovering a greater portion of fixed distribution costs through a fixed monthly charge rather than volumetric rates. In theory, this would lessen the impact of warmer- or colder-than-normal weather on customer bills and revenue recovery. However, under current Pennsylvania ratemaking practice, customer charges are generally associated with specific customer-related costs, and PECO does not have a facilities charge or other mechanism to recover general fixed distribution infrastructure costs through a fixed monthly amount. As a result, a substantial portion of fixed distribution costs remain embedded in volumetric rates. Given this framework, a WNA provides a targeted and balanced mechanism to stabilize customer bills and revenue recovery without fundamentally restructuring rate design. It preserves the existing allocation of costs between fixed and volumetric components while ensuring that customer bills and revenue recovery reflect normal weather conditions rather than actual weather in a particular year.

18. Q. Does the WNA disincentivize conservation and efficiency programs?

A. No. While the WNA adjusts revenues to account for weather-driven usage variability, it does not eliminate the price signals customers receive from their energy

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[3] National Regulatory Research Institute, *Future Test Years: Evidence from State Utility Commissions*, Report No. 13-10, at 5 (Oct. 2013), available at https://pubs.naruc.org/pub/FA86C105-05F5-9766-BC78-29829AC50361.

consumption. Customers continue to pay volumetric delivery and commodity charges, meaning their bills still reflect the amount of gas they use. In other words, using less gas will still result in lower bills and conversely, using more gas will result in higher bills.

19. Q. Does the WNA disproportionately affect low-income customers?

A. No. Customers who are enrolled in PECO's Customer Assistance Program Percentage of Income Payment Plan (CAP-PIPP) pay a fixed percentage of household income rather than a usage-based bill. As a result, their monthly payment obligations are largely insulated from weather-driven bill volatility, including any adjustments associated with a WNA.

For non-CAP customers, the WNA operates symmetrically. During milder-than-normal winters, the mechanism may result in a surcharge to align revenues with normal weather assumptions embedded in rates. Conversely, during colder-than-normal winters (such as the 2025–2026 heating season) higher-than-normal usage can lead to revenues exceeding the normal-weather level reflected in rates. In those circumstances, the WNA produces a credit to customers. Accordingly, the WNA does not disproportionately burden low-income customers. Instead, it stabilizes customer bills and revenue recovery around Commission-authorized levels while protecting all customers from over-collection during colder-than-normal periods and mitigating under-collection during milder periods.

20. Q. Does PECO's Budget Billing program serve the same purpose as the proposed WNA mechanism?

A. No. The WNA is an alternative ratemaking mechanism while PECO’s Budget Billing is a bill payment option; therefore, they serve two different purposes. The purpose of the WNA is to ensure neither customers nor the utility are harmed significantly from deviations in customer bills and revenue recovery and costs paid associated with fluctuations in weather sensitive usage, which is a source of uncertainty outside the utility’s control (i.e., the utility cannot control weather, and weather varies from normal each year). PECO’s Budget Billing program provides customers with an option to make equal monthly payments each quarter based on the previous 12-month usage. Critically, however, Budget Billing trues up to actual billed usage on a quarterly basis. Thus, for example, if weather is colder than normal, a Budget Billing customer will pay for their higher actual usage during the next quarterly true-up, but through the application of the WNA, the customer would also receive a credit for their usage in excess of the normal amount. In other words, the Budget Billing program does not change how rates are structured or how much revenue is recovered from customers; rather, it provides customers with a predictable, consistent, monthly payment option, smoothing out spikes from weather-related usage. PECO’s Budget Billing program is and will continue to be an option available to customers, but it does not address the issue of usage variation, and thus bill and revenue variations, due to changes in weather from normal.

III. HOW THE WNA WORKS

21. Q. Can you explain how the WNA adjusts customer bills?

A. The WNA modifies the delivery portion of customer bills during the heating season to reflect normal rather than actual weather conditions. It compares actual HDDs for the billing period to normal HDDs for each applicable customer. If actual weather is significantly colder than normal, outside of the 5% deadband, customers receive a credit because they used more gas than expected due to abnormal cold weather. Conversely, if weather is significantly warmer than normal, outside of the 5% deadband, customers receive a debit because they used less gas than expected. This adjustment ensures bills reflect typical seasonal conditions, reducing volatility for customers while maintaining revenue stability for the utility.

22. Q. Which customer classes and seasonal periods are covered under the proposed WNA tariff?

A. The proposed WNA will apply to PECO's customers under Rate GR General Service - Residential, and Rate GC General Service - Commercial and Industrial. The heating season is defined as the billing months of October through April. These provisions ensure that the WNA applies only to customer groups whose consumption patterns are sensitive to temperature changes and targets periods when weather-driven usage variations are most significant.

23. Q. How is the 5% deadband applied in the WNA calculation?

A. If actual HDDs differ from normal by less than 5%, no adjustment occurs. This prevents minor fluctuations in weather from impacting bills and is a common feature of WNAs in Pennsylvania.

24. Q. Please provide a formulaic representation of the WNA mechanism that you just described.

A. The Company's proposed WNA formula is shown below:

$$WNBC = BLMC + \left[\frac{NHDD +/-(NHDD * 5\%)}{AHDD} \text{ x } (AMC - BLMC) \right]$$

$$WNAC = WNBC - AMC$$

$$WNA = WNAC \text{ x Variable Distribution Charge}$$

- WNA = Weather Normalization Adjustment will be applied to bills rendered for Residential and Non-Residential customers under GR and GC rate Schedules during the heating season of October through April.
- WNBC = Weather Normalized Billing Mcfs ("WNBC") will be calculated as the Base Load Monthly Mcfs ("BLMC") added to the product of (1) the Normal Heating Degree Days ("NHDD") adjusted for a 5% deadband, divided by the Actual Heating Degree Days ("AHDD") and (2) the Actual Monthly Mcfs ("AMC") less the BLMC. WNA will not be applicable for the billing period if AMC is less than the BLMC.
- If AHDD is unavailable for any day(s) during the bill cycle, the respective NHDD for the same day(s) will also be excluded from the calculation, thereby excluding any day(s) missing AHDD from the WNBC calculation.
- BLMC represents the non-weather-sensitive portion of customer usage. It shall be established for each customer using the customer's actual average daily consumption from the billing system, measured in Mcfs, using bills in prior summers for two billing cycles with the starting read dates of June 15th multiplied by the number of days in the billing period. If less than two billing cycles of bill

history from prior summer is available for the premise, an average base load for the related customer rate schedule will be applied.

- AMC shall be measured for each customer and billing cycle. AMC will be subtracted from the WNBC to compute the Weather Normalized Adjustment Mcfs ("WNAC").
- The WNAC shall then be multiplied by the applicable Rate Schedule Distribution Charge based on service rendered to compute the WNA amount that will be charged or credited to each Residential and Non-Residential customer served under Residential GR and GC Rate Schedules.
- A deadband of 5% shall apply. The WNA for a billing cycle will apply only if the AHDD for the billing cycle are lower than 95% or higher than 105% of the NHDD for the bill cycle.
- The WNA factor shall be calculated by first adjusting the NHDD for the billing cycle by the deadband percentage of 5%. The deadband percentage shall be multiplied by the NHDD and then added to the NHDD for the billing period when the weather is colder than normal (i.e., AHDD > NHDD) or subtracted from NHDD for the billing period when the weather is warmer than normal (i.e., AHDD < NHDD).

I have included a sample calculation in Exhibit JDT-2 demonstrating how this formula will be applied for an example customer.

25. Q. Please explain the process the Company will follow to calculate the WNA.

A. For each billing cycle, the Company will adjust the heat sensitive load to account for the ratio of normal weather to actual weather and then recalculate the customer's bill. The process will work as follows:

- For each billing cycle and each applicable customer, the Company will calculate the weather normalized billing Mcfs by multiplying the heat sensitive load (actual Mcfs less base load Mcfs) times the ratio of the adjusted normal HDDs with the 5% deadband for the billing cycle to the actual HDDs. This adjusted heat sensitive load will then be added to the base load Mcfs to calculate the Weather Normalized Billing Mcfs ("WNBC");
- The Company will then determine the Weather Normalized Adjustment Mcfs ("WNAC") of each applicable customer for each billing cycle by subtracting the actual monthly Mcfs from the Weather Normalized Billing Mcfs;
- This Weather Normalized Adjustment Mcfs will then be multiplied by the applicable rate class's volumetric distribution charge to develop the Weather Normalization Adjustment that will be applied on the customer's bill.

IV. INDUSTRY PRACTICE PRECEDENT AND POLICY CONSIDERATIONS

26. Q. Is PECO's WNA proposal consistent with best practices in the utility industry?

A. Yes. PECO's proposed WNA is consistent with best practices widely recognized in the utility industry and approved by the Commission. Similar mechanisms are in place at five other Pennsylvania utilities: Columbia Gas of Pennsylvania ("Columbia Gas"), National Fuel Gas, Peoples Natural Gas Company, Philadelphia Gas Works, and UGI Utilities, Inc. – Gas Division. These programs share key design elements with PECO's proposal, including limited application during the heating season and the use of a deadband.

27. Q. Has the Commission recently reaffirmed its support for WNA mechanisms in Pennsylvania?

A. Yes. Most recently, on December 19, 2025, the Commission issued an Opinion and Order in Columbia Gas's rate case (Docket No. R-2025-3067242) that approved the continuation of Columbia Gas's WNA program. The Commission approved three enhanced customer protections that PECO has now incorporated into its proposal in this case: a 10-year normalization period, a 5% deadband, and the exclusion of the month May. The Commission's recent approval of the Columbia Gas WNA provides important context for understanding how WNA mechanisms structured with appropriate safeguards satisfy the Commission's alternative ratemaking policies and can achieve Commission approval.

28. Q. How does PECO's proposed WNA align with the factors the Commission may consider when evaluating this alternative ratemaking mechanism?

A. Exhibit JDT-1 details how PECO's proposed WNA aligns with each of the fourteen items identified for consideration by the Commission within its Statement of Policy in Docket No. M-2015-2518883.[4]

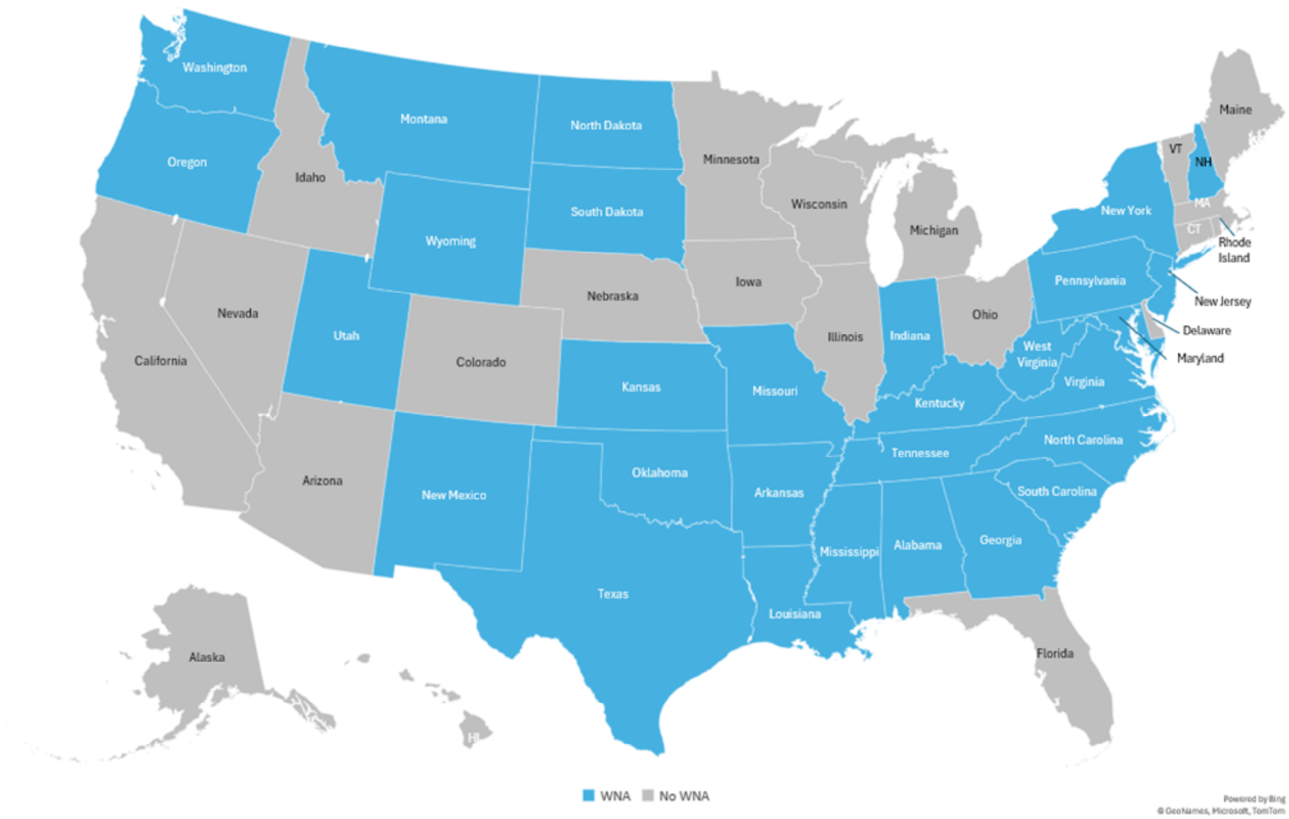
29. Q. Are WNAs unique to Pennsylvania?

A. No, WNA mechanisms are widely used across the United States to stabilize customer bills and utility revenues during abnormal weather conditions. In addition to

[4] The Commission may consider each of these factors, but each factor may not necessarily be relevant or deemed required in order to determine if an alternative ratemaking proposal is just and reasonable ("the Commission may consider, among other relevant factors, the following") Docket M-2015-2518883 PA Bulletin Dated July 1, 2020, available at https://www.puc.pa.gov/pcdocs/1633016.pdf.

Pennsylvania, 28 other states (with a total of 67 gas utilities) have adopted similar mechanisms. Figure 2 shows the states that have approved WNAs versus the ones that have not. It is worth noting that even in those states without WNA mechanisms, state commissions have approved the use of other rate design structures or alternative ratemaking mechanisms to protect customers and utilities from abnormal variations in weather, including the use of SFV rate design to recover fixed distribution costs in Ohio, and decoupling.

Figure 2 – WNA in the United States



V. ADDITIONAL CONSIDERATIONS

30. Q. What specific tariff provisions will govern the implementation of the proposed WNA mechanism?

A. The proposed provisions for the WNA will be set out in a new rider within PECO's gas tariff, identified as WEATHER NORMALIZATION ADJUSTMENT (WNA), presented in PECO Exhibit JAB-2, the Company's proposed Tariff Gas-Pa. P.U.C. No. 7, Original Page No. 82. This rider defines the purpose and scope of the adjustment, specifies the customer classes covered, and outlines the seasonal application period. It also includes the formula used to calculate adjustments based on deviations from normal HDD and the 5% deadband threshold. In addition, the tariff contains reporting and reconciliation requirements to provide transparency and regulatory oversight.

31. Q. How does PECO plan to communicate WNA adjustments to customers?

A. Customers will receive bill messages explaining when and why an adjustment has been applied, along with a brief description of how it works. In addition, PECO will provide detailed Frequently Asked Questions ("FAQs") on its website covering topics such as how the adjustment is calculated, why bills may increase or decrease, and whether it affects low-income customers. Notices will be issued before the first application of the WNA. Communication will be delivered through multiple channels, including bill inserts, the Company website, social media, and community outreach programs, so customers have access to clear and consistent information. PECO's customer service representatives will also be trained to answer customer questions regarding the WNA.

32. Q. How will PECO evaluate the accuracy of the WNA on a recurring basis?

A. PECO will evaluate the accuracy of the WNA through an annual review process that compares actual adjustments to expected outcomes. This evaluation will include an analysis of whether the mechanism maintained revenue neutrality, how closely the adjustments aligned with deviations from normal weather, and whether the deadband functioned as intended to prevent minor fluctuations from triggering changes. The review will also assess customer impacts and feedback to ensure the adjustment remains fair and transparent. Results of this evaluation will be documented in a report shared with Commission Staff and stakeholders, allowing for ongoing oversight and any necessary refinements to the mechanism. The Company is proposing to include the following information in its annual WNA report to the Commission for each month that the WNA is applied (October through April) in the applicable year: (1) the number of bills to which the WNA applied (i.e., those bills falling outside the dead band of 5%); (2) the total number of bills issued by PECO; (3) the total volume adjustment of the WNA ; (4) the total revenue adjustment of the WNA; (5) the normal calendar month weather (heating degree days); (6) the actual calendar month weather (heating degree days); and (7) a comparison of actual adjustments to expected outcomes.

VI. CONCLUSION

33. Q. Please explain how PECO's proposed WNA mechanism addresses the Commission's ratemaking principles and results in just and reasonable rates.

A. The Company's proposed WNA mechanism addresses the Commission's ratemaking principles and results in just and reasonable rates due to the following:

- PECO's proposed WNA mechanism directly addresses the concerns the Commission expressed in PECO's 2024 GRC proceeding by adopting the exact framework the Commission approved for Columbia Gas on December 19, 2025.
- PECO has incorporated Commission-approved customer protections approved in the Columbia Gas WNA: a 10-year normalization period, a 5% deadband, and the exclusion of the month of May from the period of the year during which the WNA will apply. The Commission found these protections appropriately "balance the risk of changing weather patterns between the Company and customers."[5] These safeguards address concerns about customer protection, bill predictability, and alignment with current weather conditions.
- PECO's proposed WNA addresses the fundamental challenge the Commission recognized: natural gas utilities' customer bills and revenues fluctuate with weather while delivery costs remain fixed. The mechanism provides PECO "a reasonable opportunity to earn up to its Commission-authorized revenue requirement" while protecting customers through bill credits during colder than normal weather and meaningful safeguards.[6]
- By adopting this Commission-approved framework, along with comprehensive annual reporting requirements, PECO's WNA proposal provides the revenue stability necessary for continued infrastructure investment while protecting customers, resulting in rates that are just, reasonable, and in the public interest.

For these reasons, I urge the Commission to approve the Company's proposed WNA mechanism.

[5] Columbia Gas 2025 Order at 302.
[6] Id. at 301.

34. Q. Does this complete your direct testimony?

A. Yes. However, I reserve the right to supplement my testimony, if necessary, and to respond to witnesses presented by other parties.

John D. Taylor

MANAGING PARTNER

Mr. Taylor has experience with a wide range of costing, ratemaking, and regulatory activities for gas and electric utilities. He has testified numerous times on these and other issues for clients across North America. He has extensive experience with costing and pricing rates and services, regulatory planning and strategy development, revenue recovery and tracking mechanisms, merger and acquisitions analysis, new product and service development, affiliate transaction reviews, line extension policies, market assessments, litigation support, and organizational and operations reviews. He has testified on numerous occasions as an expert witness on costing and ratemaking related issues on behalf of utilities before federal, state, and provincial regulatory bodies and has extensive experience in evaluating and implementing innovative ratemaking approaches and rate design concepts.

He has also testified on return on equity, electric vehicle and battery storage programs, time-of-use rates, and the appropriate use of statistical analysis during audit testing. Mr. Taylor has led engagements relating to gas supply planning and the review of midstream transportation and storage capacity resources. He has worked as the market monitor for New England ISO's capacity market, supported the negotiation of PPAs, and supported feasibility and prudence studies of generation investments. He has also been involved in selling generating assets and distribution companies, supporting due diligence efforts, financial analyses, and regulatory approval processes.

Mr. Taylor received a master's degree in Economics from American University and holds a bachelor's degree in Environmental Economics from the University of North Carolina at Asheville.

EDUCATION

M.A., Economics, American University

B.A., Environmental Economics, University of North Carolina at Asheville

YEARS EXPERIENCE

20

RELEVANT EXPERTISE

Utility Costing and Pricing, Expert Witness Testimony, Transaction Facilitation, Revenue Requirements, Statistics, Valuation, Market Studies, Rate Case Management, New Product and Service Development, Strategic Business Planning, Marketing and Sales

His consulting career includes Chief Executive Officer ("CEO") with Atrium Economics, LLC; Principal Consultant – Advisory & Planning with Black & Veatch Management Consulting, LLC; Senior Project Manager & Principal of Concentric Energy Advisors, Inc.; and CEO of Nova Data Testing, Inc. Mr. Taylor started his career working on Capitol Hill working with NGOs that were seeking Public Private Partnerships with the Federal Government, World Bank, and International Monetary Fund to pursue various projects in developing countries.

EXPERT WITNESS TESTIMONY PRESENTATION

UNITED STATES:

- California Superior Court of California
- Delaware Public Service Commission
- Florida Public Service Commission
- Federal Energy Regulatory Commission
- Illinois Commerce Commission
- Indiana Utility Regulatory Commission
- Maine Public Service Commission
- Massachusetts Department of Public Utilities
- Minnesota Public Utilities Commission
- New Hampshire Public Utilities Commission
- North Carolina Utilities Commission
- Oregon Public Utility Commission
- Ohio Public Utility Commission
- Pennsylvania Public Utility Commission
- Virginia State Corporation Commission
- Washington Utilities and Transportation Commission
- 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 worked on dozens of electric and gas rate cases including the development of revenue requirements, class cost of service studies, and projects related to utility rate design issues. Specifically, he has:

- Lead expert and witness for class costs of service studies across North America and worked on dozens of other class cost of service and rate design projects for other lead witnesses.
- Developed WNA mechanism for a gas utility including back casting results and supporting expert witness testimony and exhibits.

- Developed revenue requirement model to comply with a new performance-based formula ratemaking process for a Midwest electric utility.
- Supported the development of time of use rates, demand rates, economic development rates, load retention rates, and line extension policies.
- Analyzed and summarized allocation methodology for a shared services company.
- Assessed the reasonableness of costs through various benchmarking efforts.
- Led the effort to collect and organize plant addition documentation for six Midwest utilities associated with the state commission's audit of rate base.
- Supported lead-lag analyses and testimonies.
- Analyzed customer usage profiles to support reclassification of rate classes for a gas utility.
- Helped conduct a marginal cost analysis to support rate design testimony.

LITIGATION SUPPORT AND EXPERT TESTIMONY

Mr. Taylor has testified in several cases on class cost of service studies and statistical audit methods. He has also supported numerous other expert testimonies. Specifically, he has:

- Filed testimony as an expert witness on allocated class cost of service studies for both electric and gas utilities.
- Filed testimony as an expert witness on the application of statistical analysis.
- Filed testimony before FERC on the rate of return for an Annual Transmission Revenue Requirement and participated in FERC settlement conferences.
- Part of two-person expert witness team that provided an expert report to the British Columbia Utilities Commission on the use of facilities for transportation balancing services for Fortis BC.
- Part of two-person expert witness team that provided an expert report on affiliate transactions and capitalized overhead allocations for Hydro One on three separate occasions.
- Sole expert for expert report on affiliate allocations for Alectra utilities, the second largest publicly owned electric utility in North America. This was conducted shortly after the merger of four distinct utilities.
- Sole expert for expert report on the allocation of overhead costs between transmission and distribution businesses for EPCOR.

TRANSACTION EXPERIENCE

Mr. Taylor has been involved with several generating asset transactions supporting both buy side and sell side analysis and due diligence. His work has included:

- Worked as buy side advisor for a large water utility in the mid-Atlantic region including supporting the review of revenue requirements, rates, and forecasts.
- Helped facilitate and manage processes for a nuclear plant auction by processing Q&A, collecting relevant documentation and managing the virtual data room for auction participants.
- Supported the auction process for steam and chilled water distribution and generation assets in the Midwest.
- Supported the development of a financial model to ascertain the net present value of several competing wholesale power purchase agreements and guided the client with a decision matrix for the qualitative aspects of the offers.
- Provided research on comparable transactions, previous mergers and acquisitions, and potential transaction opportunities for several clients.

FINANCIAL ANALYSIS AND MARKET RESEARCH

Other financial analysis and market research Mr. Taylor has conducted include:

- Estimated the rate impact and costs associated with moving California energy market to 100% renewable.
- Assessed the consequences of a divestiture on the cost-of-service model for a New England gas distribution company.
- Developed LNG market studies for two separate utilities and two separate competitive market participants.
- Modeling alternative mechanisms for the allocation of overhead costs to a nuclear plant.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**DOCKET NO. R-2026-3060860**
PECO ENERGY COMPANY - GAS DIVISION	:	

VERIFICATION

I, John Taylor, hereby state that I am a Managing Partner at Atrium Economics, LLC; that I am authorized to and do make this Verification; and that the facts set forth in the pre-marked Statement No. 6 and accompanying exhibits, if any, are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. § 4904, relating to unsworn falsification to authorities.

Dated: March 30, 2026

John Taylor

DB1/ 167653326.1

PECO Exhibit JDT-1:
WNA Proposed Policy Factors

#	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.	PECO'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, nor do they vary with changes in temperature. The fixed costs recovered through volumetric rates include fixed operation and maintenance expenses, administrative and general expenses, depreciation, certain taxes, a portion of working capital requirements, and return on investment. 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. By stabilizing revenues, the WNA mechanism removes disincentives to support peak-reflective rate design and conservation initiatives that can moderate peak demand growth. Over time, this alignment supports more efficient use of existing system capacity while preserving the Company's ability to make prudent investments necessary to maintain safe and reliable service.
3	Whether the ratemaking mechanism and rate design reflect the level of demand associated with the	Customer specific usage factors corresponding to individual customer 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 10-year

#	Statement of Policy	Company's Response
	customer's anticipated consumption levels.	average, which captures recent weather trends and aligns normalized usage with customers' anticipated consumption levels under today's weather conditions.
4	How the ratemaking mechanism and rate design limit or eliminate interclass and intraclass cost shifting.	PECO'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 proposed WNA only addresses variations due to weather and does not affect customers' ability to pursue energy efficiency measures. Further, the Company continues and will continue to promote the use of energy efficiency measures to its customers.
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.	Customers who are enrolled in PECO's Customer Assistance Program Percentage of Income Payment Plan (CAP-PIPP) will be largely insulated from the impact to their bills under the WNA mechanism because those customers pay a fixed percentage of household income rather than a usage-based bill.
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

#	Statement of Policy	Company's Response
		adjust and any adverse impacts on the customers' operation are minimized." The proposed 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 base rate in the most recent rate case and customers would not pay more or less than that amount solely because the actual weather for the month the customers are billed is different than the weather used to determine the rate design of the volumetric base rate.
9	How weather impacts utility revenue under the ratemaking mechanism and rate design.	The Company's proposed WNA would adjust customers' bills due to variations from normal weather during the heating season months (October through April), and it mitigates the revenue effect of weather on the original rate design of the volumetric base rate (outside of the proposed five percent (5%) deadband). It only applies to Rate GR and Rate GC 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 proposed WNA would not impact the Company's rate case frequency, nor it would affect regulatory lag.
11	If or how the ratemaking mechanism and rate design interact with other revenue sources (e.g., surcharges).	PECO's WNA is solely focused on recovering costs that are part of the base revenue requirement and does not interact with other revenue sources, such as Section 1307 automatic adjustment surcharges, restructuring riders, or system improvement charges under Section 1353.

12	Whether the alternative ratemaking mechanism and rate design include appropriate consumer protections.	PECO's proposed WNA includes several consumer protections to ensure fairness and transparency, including the following: a. No Over-Recovery of Revenue: The WNA mechanism 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. The Company would not recover additional distribution revenues due to colder than average temperatures that result in higher-than-normal usage from customers. This is ensured by limiting the mechanism to the heating season and having a deadband as defined below. b. No Cross-Subsidization: The WNA is customer-specific. c. Regulatory Oversight: The WNA would be 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: PECO plans to provide clear bill disclosures and customer education regarding WNA adjustments, ensuring consumers understand how the mechanism works and how it impacts their bills. e. 10-Year Normalization Period which better reflects recent weather. f. Five precent (5%) deadband to prevent minor fluctuations from impacting bills. g. Exclusion of the month of May for the applicable heating season (October through April).
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 would provide detailed information to the customer of how the mechanism would work and the adjustments would be displayed separately on bills, ensuring full transparency. The Company plans to implement clear customer communications, including bill inserts, a customer Frequently Asked Questions (FAQ) document, and will have trained customer service representatives to address customer questions.

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 would help minimize the volatility of the recovery of these costs.

PECO Exhibit JDT-2:
WNA Calculation Example

Example A: This example illustrates how the WNA is calculated for a residential customer during one winter billing cycle when weather is colder than normal.

Line	Description	Input	Calculation	Result
1	Base Load Monthly Consumption (BLMC)	10.00 Mcf		
2	Actual Monthly Consumption (AMC)	60.00 Mcf		
3	Normal Heating Degree Days (NHDD)	1,000 HDD		
4	Actual Heating Degree Days (AHDD)	1,150 HDD		
5	Adjusted NHDD for 5% deadband[1]		Line 3 x (1 + 0.05) = 1,000 x 1.05	1,050 HDD
6	Weather-sensitive usage		Line 2 - Line 1 = 60.00 − 10.00	50.00 Mcf
7	Weather-Normalized Billing Consumption (WNBC)		Line 1 + ((Line 5 ÷ Line 4) x Line 6) = 10.00 + ((1,050 ÷ 1,150) × 50.00)	55.65 Mcf
8	Weather Normalization Adjustment Consumption (WNAC)		Line 7 – Line 2 = 55.65 − 60.00	(4.35) Mcf
9	Variable Distribution Charge (proposed)	$8.0793/Mcf		
10	**Weather Normalization Adjustment (WNA)**		Line 8 x Line 9 (4.35) × $8.0793	**$(35.14)**

Final Result (Line 10): Because weather during the billing period was colder than normal, customers used more natural gas for heating than they would have under normal weather conditions. The WNA therefore results in a $35.14 credit to the customer's bill.

[1] When weather is colder than normal (AHDD > NHDD), the 5% deadband is applied by multiplying NHDD by (1 + 0.05).

Example B: This example illustrates how the WNA is calculated for a residential customer during one winter billing cycle when weather is warmer than normal.

Line	Description	Input	Calculation	Result
1	Base Load Monthly Consumption (BLMC)	10.00 Mcf		
2	Actual Monthly Consumption (AMC)	60.00 Mcf		
3	Normal Heating Degree Days (NHDD)	1,000 HDD		
4	Actual Heating Degree Days (AHDD)	900 HDD		
5	Adjusted NHDD for 5% deadband[2]		Line 3 x (1 - 0.05) = 1,000 x 0.95	950 HDD
6	Weather-sensitive usage		Line 2 - Line 1 = 60.00 − 10.00	50.00 Mcf
7	Weather-Normalized Billing Consumption (WNBC)		Line 1 + ((Line 5 ÷ Line 4) x Line 6) = 10.00 + ((950 ÷ 900) × 50.00)	62.78 Mcf
8	Weather Normalization Adjustment Consumption (WNAC)		Line 7 – Line 2 = 62.78 − 60.00	2.78 Mcf
9	Variable Distribution Charge (proposed)	$8.0793/Mcf		
10	**Weather Normalization Adjustment (WNA)**		Line 8 x Line 9 2.78 × $8.0793	**$22.46**

Final Result (Line 10): Because weather during the billing period was warmer than normal, customers used less natural gas for heating than they would have under normal weather conditions. The WNA therefore increases the bill by $22.46 to reflect usage under normal weather.

[2] When weather is warmer than normal (AHDD < NHDD), the deadband is applied by multiplying NHDD by (1 − 0.05).