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May 31, 2024

Via E-Filing

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17105-3265

SUBJECT: PECO Purchased Gas Cost No. 41, Effective December 1, 2024
Docket No. R-2024-3048767, Supplement No. 15 to Gas Service Tariff No. 5

Dear Secretary Chiavetta:

This letter transmits for filing with the Pennsylvania Public Utility Commission (the "Commission") the Purchased Gas Cost ("PGC") No. 41 filing of PECO Energy Company, consisting of the following:

1. Statement No. 1 – Direct Testimony of Suzette E. Adams
2. Statement No. 2 – Direct Testimony of Scott J. Hughes (including exhibit)
3. Statement No. 3 – Direct Testimony of Julie S. Drezner (including exhibits)
4. Statement No. 4 – Direct Testimony of Anthony P. DiFelice (including exhibits)

As required by Commission Order entered December 6, 1985, at Docket No. P-850081, the Company has begun the advance public notice of the proposed gas rate changes contained in the PGC No. 41 filing through bill inserts and newspaper advertisements.

Additionally, this package is being served only via email to those on the Certificate of Service, per their requests for electronic service only.

All correspondence, pleadings and other documents should be sent electronically to the attention of:

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Sincerely,

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cc: K. Hafner, Director, Office of Special Assistants (via e-mail only)
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K. Monaghan, Director, Bureau of Audits (via e-mail only)

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	**Docket No. R-2024-3048767**
v.	:	
	:	
PECO ENERGY COMPANY	:	

CERTIFICATE OF SERVICE

I hereby certify that I am this day serving a true copy of the PECO's Annual 1307(f) Purchased Gas Cost Filing upon the participants listed below in accordance with the requirements of 52 Pa. Code Section 1.54 (relating to service by a participant).

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Dated: May 31, 2024

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
V.
PECO ENERGY COMPANY

Docket No. R-2024-3048767

DIRECT TESTIMONY
OF
SUZETTE E. ADAMS

PECO STATEMENT NO. 1

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DIRECT TESTIMONY OF SUZETTE E. ADAMS

I. INTRODUCTION

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

A. My name is Suzette E. Adams. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, PA 19103.

2. Q. What is your educational background?

A. I hold a Bachelor's Degree in Accounting from Temple University and a Master's Degree in Business Administration from Eastern University.

3. Q. Have you previously submitted testimony in rate proceedings?

A. Yes. I have submitted testimony on behalf of PECO Energy Company ("PECO" or the "Company") in the Purchased Gas Cost ("PGC") 40 proceeding at Docket No. R-2023-3040285.

4. Q. Please describe your work experience relevant to your Direct Testimony.

A. I have been employed at PECO or its affiliate, Exelon Business Services Company ("Exelon BSC") since May 2002. I started as a Senior Accountant in the accounting department of Exelon BSC. In that role, I performed functions of an accountant which included journal entries, account reconciliation, depreciation expenses and prepared various internal and external (SEC, FERC, PUC) reporting. In 2006, I became the Senior Gas Supply & Transportation Analyst. My responsibilities included tracking departmental Key Performance Indicators, supply planning, storage asset management, asset optimization, daily, monthly, seasonal and long-term natural gas purchasing, analyzing and authorizing capacity releases and scheduling natural gas flow on interstate pipelines. Over the last seven years I worked in Project Management overseeing large scale projects, I managed the call center, and was the Chief of Staff to the Chief Customer Officer (CCO) in Customer Operations.

5. Q. Please identify your current job responsibilities.

A. In May 2022, I became the Senior Manager of PECO's Gas Supply & Transportation Department. In this position, I manage all aspects of PECO's natural gas supply acquisition portfolio including contract negotiation, administration and accounting, gas supply procurement, risk management, off-system sales and capacity release, and long and short-term supply planning. This includes management and optimization of upstream pipeline storage assets and pipeline transportation, as well as decisions on hedging strategies for future supplies. I am also responsible for reviewing all gas supply and capacity costs and providing testimony regarding all gas acquisition activities at the annual Pennsylvania Public Utility Commission (the "Commission") Purchased Gas Cost Proceeding. In addition, I am also responsible for oversight of the high-volume transportation program and management of Federal Energy Regulatory issues impacting PECO Gas and its customers.

II. PURPOSE OF TESTIMONY

6. Q. What is the purpose of your Direct Testimony in this proceeding?

A. The purpose of my Direct Testimony is to present the information required in Section 1317(a) of the Pennsylvania Public Utility Code (the "Code") (*See* 66 Pa. C.S.A. § 1317(a)) so that the Commission may make the findings required by Section 1318 of the Code (*See* 66 Pa. C.S.A. § 1318) for a determination that PECO's PGC rates and charges for the historic period (April 1, 2023 through March 31, 2024), the estimated period (April 1, 2024 through November 30, 2024) and the

PGC application period (December 1, 2024 through November 30, 2025) are just and reasonable. To that end, I am sponsoring the information previously filed by the Company on April 30, 2024 (the "Advance Information") in support of this year's purchased gas cost proceeding ("PGC 41"). Additionally, I will describe the Company's natural gas purchase policies and practices, including PECO's use of natural gas pipeline transportation and storage contracts, and set forth its plans for evaluating and continuing to incorporate Marcellus Shale production into its supply portfolio.

7. Q. Are you sponsoring any exhibits?

A. No, I am not sponsoring any exhibits. However, as previously mentioned, I am sponsoring the Advance Information, which has been separated into Sections 1 through 22, and which correspond, generally, to the PGC filing requirements set forth in 66 Pa. C.S.A § 1317.

8. Q. Please provide a general description of PECO's natural gas system.

A. PECO's natural gas system is located in Southeastern Pennsylvania and serves the four-county area surrounding, but not including, the City of Philadelphia and a portion of Lancaster County. Because this is not a natural gas-producing region, PECO and its natural gas customers depend on the interstate natural gas pipeline system to deliver natural gas into PECO's distribution system. This dependency applies to all natural gas supplies, storage, and interstate transportation services, except for PECO's two on-system peak-shaving facilities. For a schematic of PECO's natural gas system, please refer to Section 13 of the Advance Information.

9. Q. Please identify PECO's interstate transmission suppliers.

A. Texas Eastern Transmission, LP ("Texas Eastern"), Transcontinental Gas Pipeline Corporation ("Transco"), Eastern Shore Natural Gas Company ("Eastern Shore"), and Adelphia Gateway are the four interstate natural gas pipelines that deliver natural gas directly to PECO's city gates. In addition, Eastern Gas Transmission and Storage, Inc. ("EGTS"), Texas Eastern, and Transco also provide natural gas storage services, which PECO uses to meet winter daily and peaking requirements. In the case of EGTS' storage service, intermediate transportation service from Texas Eastern is required to deliver the natural gas to PECO's city gate.

III. <u>HISTORIC AND PROJECTED NATURAL GAS PURCHASES</u>

10. Q. Please describe the information provided in Section 1 of the Advance Information.

A. The information provided in Section 1 of the Advance Information accounts for all of the Company's purchased natural gas costs during the period from January 1, 2023 through March 31, 2024 and includes the source of the natural gas, the price and the associated volumes. This information also includes applicable rates, demand components, and incremental purchased natural gas costs associated with contracted interstate pipeline transportation and storage services. All costs detailed in Section 1 result from applying the Company's policy to purchase natural gas on a basis that ensures system reliability at the least-cost.

11. Q. During the past 12 months, did PECO purchase natural gas from any affiliated interest?

A. No, PECO did not purchase natural gas from any affiliated interest during the past 12 months.

12. Q. Has PECO withheld or caused to be withheld from the market any natural gas supplies which should have been utilized as part of a least-cost fuel procurement policy?

A. No. Because PECO is neither a natural gas producer nor a wholesale market participant of significant size or scope, it could not benefit from withholding any natural gas supplies from the market. For these same reasons, PECO has no market power in the pipeline capacity market. PECO only engages in purchases related to providing natural gas service to its retail customers and a small amount of off-system sales from which its retail customers derive substantial benefit.

13. Q. Has PECO included in its PGC rates any purchased natural gas costs that should be charged to transportation customers?

A. No. When a transportation customer uses PECO's purchased natural gas under Rate IS ("Interruptible Service"), these fuel costs are excluded from costs to be recovered from PECO's PGC customers. In addition, PECO provides Standby Sales Service for firm and interruptible transportation customers whereby those customers may purchase natural gas from the Company at the standard retail rate should a customer's supplier fail to deliver gas. The demand charge revenues derived from Standby Sales Service are credited toward recovery of purchased natural gas costs through the Section 1307(f) mechanism. If a firm transportation

("FT") customer fails to elect Standby Sales Service and nevertheless uses PECO's purchased natural gas to make up for deficient supplier deliveries, or if an interruptible customer consumes unauthorized volumes, the customer is charged tariff rates for the natural gas used and assessed a penalty for the delivery deficiency. These penalty revenues are also credited to PECO's PGC customers.

14. Q. Please describe the information provided in Sections 6 and 7 of the Advance Information.

A. Sections 6 and 7 of the Advance Information provide the projected cost of purchasing natural gas for the estimated period (April 1, 2024 through November 30, 2024) and the PGC application period (December 1, 2024 through November 30, 2025), respectively. This information includes the expected source of the natural gas, the price, and the associated volumes. The projected purchases reflect the Company's policy to purchase natural gas on a basis that ensures system reliability at the least-cost. Sections 6 and 7 of the Advance Information include all projected interstate pipeline costs, storage demand costs, variable storage and fuel-related costs, and commodity costs for the relevant time periods. As shown in Section 6 of the Advance Information, the total projected cost applicable to the PGC for the estimated period is approximately $120.228 million. As shown in Section 7 of the Advance Information, the total projected cost applicable to the PGC for the application period is approximately $318.721 million.

IV. <u>DESIGN DAY REQUIREMENTS</u>

15. Q. Have you provided an overview of the methodology the Company employs to determine design day requirements?

A. Yes. Details of PECO's design day methodology and a description of its 2024-2025 winter design day requirements are included in Section 16 of the Advance Information. As described in Section 16, PECO's supply resources, combined with peaking and delivered supply, will satisfy the Company's design day requirement of 902,036 Mcf for the 2024-2025 winter season.

16. Q. Is PECO proposing a change to its design day as a result of its experience during the 2023-2024 winter season?

A. No. PECO's design day methodology, as well as system performance this past winter, supports the continued use of a zero degree design day.

V. <u>PECO'S NATURAL GAS PURCHASE POLICIES AND PRACTICES</u>

17. Q. Does PECO pursue a least-cost procurement policy?

A. Yes, it does.

18. Q. Please describe PECO's least-cost procurement policy.

A. PECO's natural gas procurement policy is designed to achieve a reasonable balance of long- and short-term natural gas purchases under different pricing approaches, in order to achieve system supply reliability at the least-cost. As previously discussed, the details of PECO's actual natural gas purchases for the fifteen (15) months ending March 31, 2024 and its estimated purchases through November 30, 2025 are presented in the Advance Information (Sections 1, 6 and 7). PECO utilizes its interstate transportation and storage entitlements to obtain and deliver market-priced supplies to the PECO natural gas distribution system.

19. Q. Please explain the practical implementation of the policy.

A. PECO manages its least-cost procurement strategy through purchases made under long-term (more than one month), such as purchases made in conjunction with the Ratable Hedging Program and short-term (one month or less) contracts, and on the daily spot market. Purchases made under long- and short-term contracts generally use two pricing mechanisms: (1) daily or first-of-the-month indices; and (2) adjusted New York Mercantile Exchange ("NYMEX") futures pricing. Index-based pricing refers to the use of either a first-of-the-month index at a particular location, such as the index published in the *Inside FERC Gas Market Report*, or a daily index at a particular location, such as those published in *Gas Daily*. NYMEX futures pricing refers to the use of a selection of monthly natural gas futures prices from a NYMEX futures contract pricing screen, or a monthly NYMEX settlement price, plus or minus a negotiated locational basis. PECO receives bids from suppliers for the lowest basis numbers, which, when added to the applicable NYMEX futures price or NYMEX settlement price, affords PECO the least-cost natural gas price at its city gate.

Spot purchases are made at either a daily index or a fixed price. PECO also uses Requests for Proposals ("RFPs") to obtain least-cost bids for natural gas supplies. In this process, the bids may or may not contain a premium or discount depending on the market and time of year.

Additionally, PECO continued and extended its Ratable Hedging Program as authorized by the Joint Petition for Complete Settlement in last year's PGC proceeding at Docket No. R-2023-3040285.

20. Q. Why does PECO employ a variety of pricing approaches rather than just one?

A. PECO uses different pricing approaches to reduce the price volatility risk associated with using only one approach. The flexibility of using different pricing methods has enabled PECO to diversify its natural gas-purchasing portfolio. By employing these various options, PECO reasonably limits its exposure to intra-month, monthly and seasonal pricing volatility.

21. Q. What other methods does PECO use to mitigate its exposure to price volatility?

A. One additional method PECO uses to mitigate its exposure to price volatility is to use its interstate transportation contracts for supply purchases from geographically diverse locations that have substantial liquidity. This allows PECO the flexibility to analyze the market and optimize its purchases to reduce the price of natural gas delivered to its city gate, considering both commodity and transportation costs. PECO's interstate transportation capacity ensures access to supplies from the Gulf of Mexico, mid-continent, and the Appalachian region, which includes Marcellus Shale natural gas supplies from Pennsylvania and other Marcellus Shale natural gas-producing areas.

PECO also mitigates its exposure to price volatility by using its interstate pipeline storage entitlements. In addition to providing a source of wintertime deliverability, access to pipeline storage allows PECO to purchase natural gas during the summer period. The natural gas procured in the summer period can be redelivered during periods of strong demand, when prices could potentially be higher (typically, the winter period). However, summer prices for natural gas are not always predictably lower than winter prices.

22. Q. Does storage provide PECO with a substantial source of supply?

A. Yes. As shown in Sections 16 and 22 of the Advance Information, 27.65% of the Company's required design day supply, which equates to 250,600 Mcf, will be received via delivery from contracted underground storage. In addition, LNG, propane, and delivered peaking services combine to represent about 26.89% of the required design day supply. Accordingly, as shown in Sections 16 and 22 of the Advance Information, 190,000 Mcf are available from LNG, 24,807 Mcf are available from propane, 28,902 Mcf are available from delivered hedged contracts.[1] Overall, the use of storage and LNG enables PECO to substantially mitigate its exposure to the price volatility that typically occurs during the winter, while ensuring sufficient deliverability to meet firm demand.

PECO plans to fill its contracted storage to approximately ninety-five percent (95%) of capacity, in the aggregate, by October 31 of each year. For a typical winter, PECO reduces the inventory of natural gas in its contracted storage to approximately 20% of capacity by March 31 of each year. Additionally, PECO can store 1.2 Bcf of natural gas at its on-system LNG facility, which is filled to capacity during the summer liquefaction season.

[1] For the upcoming 2024-2025 winter, PECO entered into two types of winter-delivered supply contracts that reduce the quantity required to be obtained via RFP to meet its peak day. First, PECO has under contract a 10-day call option for 40,000 Dth/day of delivered supply priced at summer index prices plus demand charges. Second, PECO, through its approved hedging program, entered into fixed price delivered supply contracts equal to 30,000 Dth/day.

23. Q. Are there limitations on PECO's source of supply from its LNG facility, its propane facility, or contracted storage?

A. Yes, there are certain system operational considerations the Company must consider when using LNG, propane, or storage supply. The LNG, propane, and contracted underground storage tanks are filled during the summer months, and the natural gas in those tanks must last through the winter months (November – March). The Company closely monitors LNG, propane, and storage inventory, especially from November through January, to ensure our ability to meet customer needs through the winter and early spring.

24. Q. Please explain PECO's strategy to ensure system reliability.

A. PECO's reliability strategy is two-fold. First, PECO must ensure that sufficient capacity exists to satisfy design day deliverability requirements. This capacity is diversified into three categories: (1) pipeline FT capacity; (2) pipeline storage capacity; and (3) peaking capacity. Peaking capacity refers to PECO's LNG facility, propane-air facility, and contracted peaking services with reliable third-party suppliers.

Second, PECO must ensure that a firm source of supply exists to utilize the capacity resources described above. PECO ensures the availability of firm supplies through its contractual arrangements with its suppliers. PECO subjects all potential counterparties to a credit analysis. If the credit analysis deems the counterparty acceptable, PECO will negotiate a NAESB Agreement with the counterparty, which enables PECO to procure natural gas at competitive prices for its PGC customers.

25. Q. What was PECO's experience regarding meeting customer demand this past winter?

A. As illustrated in Table SA-1 below, PECO experienced a winter that was overall, by degree day, 11.6% warmer than a normal winter. December was -17.4% colder than normal.[2] Variations from normal weather by season, month, or day present balancing challenges. These challenges can be exacerbated by certain factors. For example, on warmer than normal days, they can be made worse by the increase in firm supply receipts associated with the LVT Gas Choice program and the Company's Ratable Hedging Program, and on colder than normal days, by exposure to market area price volatility and limited LNG, propane and underground storage inventory. PECO utilized its balancing assets, such as contracted storage, as well as its daily load balancing processes to minimize costs this past winter.

<u>Table SA-1</u>

Heating Degree Days (HDD)						
	November 2023	December 2023	January 2024	February 2024	March 2024	Total
HDD Normal	511	799	958	810	642	3,720
HDD Actual	540	660	872	714	503	3289
Difference	29	-139	-86	-96	-139	-431
HDD vs Normal	5.7%	-17.4%	-9.0%	-11.8%	-21.7%	-11.6%

[2] PECO defines a normal winter as 3,854 heating degree days ("HDD").

26. Q. Was there any impact on PECO's contracted supply, or on the operation of the Company's on-system propane or LNG facilities for the duration of the winter weather period?

A. No. PECO did not experience any interruptions or reductions in its contracted natural gas deliveries. Although the winter was relatively warm, the Company's propane and LNG facilities were available to operate in a safe and efficient manner if needed; supplies from those assets remain crucial in allowing the Company to meet the high customer demand experienced during the normal winter weather periods.

27. Q. Did PECO enter into any Off-System Sales where the purchase price exceeded the sales price? If so, please explain.

A. Yes. On April 14, 2023, to avoid potential pipeline penalties, PECO sold 18,000 Dth per day at $1.2775/Dth against a purchase price of $1.5575/Dth for a net loss of $5,040. The reasons for the sale were unseasonably warm weather, the projected average temperature was within the less than 5% statistical probability range, Texas Eastern issued an OFO warning for penalties for gas left on the pipe and also because S-2 injections per contract are not available until April 16th of each year.

28. Q. Did the past winter result in any new records for the Company's natural gas system sendouts?

A. No. For context, Table SA-2 below, provides the top 20 highest sendout days in the Company's history.

Table SA-2

Rank	System Sendout MCF	System Sendout DTH	Date	Airport Temperature	Wind Speed
1	803,438	842,026	Saturday, January 6, 2018	11	13
2	793,273	829,341	Friday, January 5, 2018	12	21
3	777,457	826,437	Sunday, February 15, 2015	10	20
4	767,421	826,143	Thursday, February 19, 2015	11	19
5	779,424	820,160	Sunday, December 31, 2017	12	10
6	781,516	814182	Monday, January 21, 2019	16	13
7	779,531	813,851	Thursday, January 31, 2019	15	13
8	758,591	809,417	Tuesday, January 7, 2014	11	14
9	769,719	801927	Friday, February 1, 2019	15	13
10	765,275	798674	Wednesday, January 30, 2019	14	13
11	777,330	791653	Saturday, December 24, 2022	18	19
12	738,003	789,663	Friday, February 20, 2015	14	8
13	748,358	786,130	Monday, January 1, 2018	16	13
14	750,530	783,302	Thursday, January 4, 2018	19	22
15	748,912	775,873	Saturday, January 29, 2022	18	16
16	733,825	773,227	Tuesday, January 2, 2018	20	9
17	723,486	770,513	Wednesday, January 7, 2015	16	18
18	717,189	763,790	Saturday, February 13, 2016	15	17
19	734,810	763,436	Saturday, January 15, 2022	19	10
20	721,526	760,693	Thursday, December 28, 2017	17	9

29. Q. Did PECO incur any pipeline penalties this past year?

A. No, PECO did not incur any pipeline penalties this past year.

30. Q. Did PECO's supply contracts perform as required during the winter of 2023-2024?

A. Yes. For the winter of 2023-2024, all natural gas scheduled under PECO's supply contracts was delivered to PECO's city gate.

31. Q. Based on its experience in recent winters, is PECO considering any changes to its natural gas supply portfolio?

A. Yes, while the Company believes that its current mix of FT, firm storage, propane, LNG, and delivered peaking contracted services provides adequate peaking capacity to ensure the system reliability necessary to meet peak demand in a safe, least-cost manner at present, PECO continues to analyze supply portfolio and on-system LNG solutions to address observations from experiences these past few winters, as well as for peak-day demand projections. Although this past winter was relatively mild, the Company's projected growth in design day and overall demand supports the Company's continuing review of how to best manage its natural gas supply portfolio. To that end, PECO has continued its examination of potential long- and short-term solutions to assist in meeting customer demand during the heating season, including peak-day demand. The results of this examination are discussed below in response to Questions 34 through 36.

32. Q. Please provide an update on the steps the Company took to ensure availability of supply for the winter of 2023-2024.

A. As described in the Direct Testimony in PECO's prior PGC proceedings,[3] PECO continues to analyze and adopt multiple solutions to procure reliable, least-cost assets for both the short- and long-term peak day supply deficits. To that end, to ensure the availability of winter delivery services for the winter of 2023-2024 (as explained at page 2 of Section 22 of the Advance Information in PGC 40 (Docket

[3] *See* Direct Testimony of Carlos P. Thillet (PGC 35 through 38) and Direct Testimony of Scott J. Hughes (PGC 39).

No. R-2023-3040285)), PECO took the following steps to acquire the 128,695 Dth needed:

- PECO entered into a contract for a 10-day call option for 40,000 Dth/day of delivered supply at summer index prices, plus demand charges;
- PECO procured 36,000 Dth/day of delivered supply via the Company's approved Ratable Hedging program.
- PECO contracted for 32,922 Dth/day of REA early in-service capacity October 2023
- PECO also procured a 10 day call option for 20,043 Dth/Day via an RFP issued on September 11, 2023

33. Q. Did PECO purchase any trucked LNG or propane under the aforementioned call options and if so, why?

A. No, PECO did not purchase any trucked LNG or propane under the aforementioned call options.

34. Q. How does the Company plan to ensure availability of supply for the winter of 2024-2025?

A. PECO will utilize both short- and long-term solutions to address its supply needs for the winter of 2024-2025. As to the short-term solutions, similar to previous winters, PECO will depend on delivered supply in order to meet part of its design day requirements.[4] PECO has taken the following steps to ensure the availability of the 70,000 Dth/day of required delivered supply:

- PECO has in place a multi-year contract for a 10-day call option for 40,000 Dth/day of delivered supply at summer index prices, plus demand charges; and
- PECO will procure 30,000 Dth/day of delivered supply via the Company's Ratable Hedging program.

[4] PECO's design day requirements can be found at page 2 of Section 22 of the Advance Information.

In addition, PECO will take the following steps to obtain the remainder of the delivered natural gas resources needed:

- On or before July 1, 2024, PECO will issue a notice of Additional Capacity Constraints, as explained in the Company's DSO program, which is anticipated to produce a similar yield as in prior years.
- PECO will issue an RFP for delivered supply equal to the total winter delivered resources required, less those volumes obtained by the two contracts and DSO program participation listed above.

35. Q. Please describe the actions PECO is pursuing to address the longer term peak day requirements through the winter of 2030-2031.

A. To reduce reliance on delivered supply, the Company continues to investigate longer term solutions. The objectives of the longer-term solution are to provide PECO with a least-cost, reliable source of supply enabling the Company to meet its firm demand, eliminate the peak-day supply gap, while providing deliveries to PECO gate stations and further eliminating exposure to market area price volatility. To that end, PECO is currently involved in two projects that will aid it in meeting its long-term supply objectives.

First, PECO has continued its evaluation of participation in pipeline open seasons as a way of securing additional cost-effective FT to PECO's City Gate. As discussed below (also see the Company's response to Question 10, PECO Statement No. 3, the Direct Testimony of Julie Drezner) PECO's continued efforts to evaluate pipeline open seasons and capacity made available via permanent capacity releases to see if any new, cost-effective, firm natural gas transportation source to PECO's city gate became available. Provided in that discussion is a description of the Company's involvement in the Transco Regional Energy Access ("REA") Project. A portion of the REA Project is now in service and the additional contracted amount is projected to be in service by the end of summer 2024 and will provide PECO with 100,000 Dth/day of Firm Capacity from the Leidy Marcellus production area to PECO's City gate.

Second, as discussed in the Direct Testimony of Scott J. Hughes in PGC 39, and in detail in the Direct Testimony of Carlos P. Thillet submitted in PGC 32 through PGC 38, PECO has continued its LNG investment and continues to take actions that will lead to increasing LNG Vaporization capability at the Company's West Conshohocken facility from 160,000 Mcf/day to 220,000 Mcf/day, directly reducing reliance on delivered supply. The Natural Gas Reliability Project, of which the increased LNG Vaporization capability is a part, is also discussed in depth in the Direct Testimony of Carlos P. Thillet (PECO Statement No. 2) in Docket No. P-2021-3024328.[5] In that proceeding, PECO explained the need for the Natural Gas Reliability Project from the standpoint of ensuring the reliability of PECO's natural gas supply to meet design day requirements~~.~~

36. Q. How will the actions taken by PECO described above reduce the currently projected deficit between currently contracted-for pipeline storage and FT deliveries, as well as LNG and propane capacity and peak day demand requirements?

A. First, for reference, Table SA-3 provides a comparison of projected design day demand compared to current and planned future assets.

[5] PECO filed its Petition for a Finding of Necessity on May 14, 2021. A copy of the Direct Testimony in Docket No. P-2021-3024328, which is confidential, will be made available upon request and execution of a confidentiality agreement acceptable to PECO.

Table SA-3

DESIGN DAY DEMAND VS ASSETS (Dth/D)					
WINTER	DESIGN DAY DEMAND	PROJECTED TOTAL ASSETS	GAP	% GAP	Notes
2024-2025	936,313	980,568	44,255	5%	Assets equal current Pipeline FT and Storage deliveries plus PECO LNG and Propane vaporization assets. Includes Hedged Gas for executed contracts of 30,000 Dth/d and 61C Tioga contract of 40,000 Dth/d. Transco REA project planned in service date increases FT deliveries by 77,500 DTH/d. Reliability Project increased LNG vaporization by 35,500 DTH/d.
2025-2026	949,000	970,568	21,568	2%	61C/Tioga contract expires and decreases 40,000 Dth/d. Completion of the LNG reliability project increases LNG vaporization 30,000 DTH/d.
2026-2027	958,000	930,568	-27,432	-3%	Assets at steady state
2027-2028	969,000	930,568	-38,432	-4%	
2028-2029	986,000	930,568	-55,432	-6%	
2029-2030	987,000	930,568	-56,432	-6%	
2030-2031	988,000	930,568	-57,432	-6%	
2031-2032	989,000	930,568	-58,432	-6%	
2032-2033	990,000	930,568	-59,432	-6%	
2033-2034	991,000	930,568	-60,432	-6%	

The projected total assets for the winter of 2024-2025 include all of PECO's current firm assets, which increase by 113,000 Dth/day beginning in the winter of 2025-2026, and by an additional 30,000 Dth/day beginning in the winter of 2025-2026, resulting in a total additional 143,000 Dth/day.[6]

The acquisition of these firm assets will result in the elimination of the current firm gap between total assets and design day demand of -6.0%. By the winter of 2033-2034, PECO will have supplemental capacity beyond the projected design day of 2%. This supplemental capacity will better enable the Company to serve its customers should future instances occur where any of the interstate

[6] These increases in firm assets are directly tied to the in-service dates of the Company's Natural Gas Reliability Project and the REA project, respectively.

pipelines delivering supply to PECO's service area are subjected to equipment failures, integrity concerns, or other obstacles or force majeure events that prevent them from meeting their contracted obligations during periods of high natural gas demand. Supplemental capacity would also provide a degree of flexibility to ensure deliverability and help to lessen exposure to market area price volatility.

VI. REGIONAL AND SUSTAINABLE NATURAL GAS ACQUISITION STRATEGY

37. Q. Has the Company purchased any natural gas produced in Marcellus Shale regions?

A. Yes. PECO has purchased natural gas from Marcellus Shale production areas. Since 2010, PECO has incorporated increasing quantities of locally-produced Marcellus Shale natural gas into its portfolio of supply assets. The only supply PECO purchases that it presumes is not from the Marcellus production regions are those necessary for injections into its WSS storage contract, located upstream on Transco's main line.[7] PECO uses its FT contracts to purchase and transport natural gas primarily from both the Southwestern and the Northeastern/Leidy production areas in Pennsylvania.

PECO projects that most of its purchases going forward, other than those needed to refill its Transco WSS storage contract located in the Gulf Area storage, will be made at pooling points inside of Pennsylvania. PECO, however, remains mindful of its obligation to seek the least-cost natural gas for its customers. As such, it retains the ability to adjust its purchase points to coincide with changes to

[7] Due to the location of certain purchase receipt points, the Company reasonably assumes they are supported by Marcellus Shale gas produced in Pennsylvania. However, the Company is not privy to pipeline information regarding physical flows to the well head. Nor does the Company's least-cost obligation to its firm customers require it to request such proof from its counterparties.

industry fundamentals should those changes affect the cost of natural gas in different locations.

38. Q. Please describe any steps the Company has taken to Acquire Renewable Natural Gas (RNG).

A. PECO has continued to pursue a strategy to procure and support the growth of RNG production and secure a reliable source of RNG supply onto PECO's gas system at market-based gas prices. As previously noted in prior PGC filings, while PECO does not intend to pay a premium for, or otherwise acquire, the environmental attributes of the RNG, PECO would like maximum flexibility to pursue sources of RNG production that would be most advantageous to PECO's PGC customers.

Per the PGC 40 Settlement, if PECO were to acquire RNG, it committed to do so in a manner that is consistent with the Company's least-cost procurement strategy for natural gas, *e.g.*, it would pursue the least cost RNG, and would undertake commercially reasonable efforts to minimize the cost impact to PECO'S PGC customers from the costs associated with purchasing RNG.

VII. CONCLUSION

39. Q. Does this conclude your Direct Testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
V.
PECO ENERGY COMPANY

Docket No. R-2024-3048767

DIRECT TESTIMONY
OF
SCOTT J. HUGHES

PECO STATEMENT NO. 2

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DIRECT TESTIMONY OF SCOTT J. HUGHES

I. INTRODUCTION

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

A. My name is Scott J. Hughes. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, PA 19103.

2. Q. What is your educational background?

A. I received a Bachelor of Arts degree from Eastern University in 1994. I received a Master of Science degree from the University of Pennsylvania in 1997.

3. Q. Have you previously submitted testimony in rate proceedings?

A. Yes. I submitted testimony on behalf of PECO Energy Company ("PECO" or the "Company") in the following Purchased Gas Cost ("PGC") proceedings:

PGC 21	Docket No. R-0049423
PGC 37	Docket No. R-2020-3019661
PGC 38	Docket No. R-2021-3025629
PGC 39	Docket No. R-2022-3032250
PGC 40	Docket No. R-2023-3040285

4. Q. Please describe your work experience relevant to your Direct Testimony.

A. I have been employed by PECO since 1986. I started as a Credit Analyst and I have also spent time doing analytical work in both Revenue Protection and Customer Service. In 1995, I joined the Regulatory Performance and Planning Group as a Regulatory Assessor and in 1998, I joined the Large Account Services Group as an Account Manager for Commercial Developers. I joined the Gas Supply Group in 1999 as a Senior Operations

Area Analyst, then from 2001 to 2007, I worked as a Senior Natural Gas Analyst, before transitioning to the position of Principal Acquisition Analyst, which I held until May 2019. Over that time, my responsibilities included tracking departmental Key Performance Indicators, supply planning, storage asset management, asset optimization, daily, monthly, seasonal and long-term natural gas purchasing, analyzing and authorizing capacity releases and scheduling natural gas flow on interstate pipelines.

5. Q. Please identify your current job responsibilities.

A. In June 2019, I became the Manager of PECO's Gas Acquisition Department. In this position, I am responsible for the day-to-day management and oversight of the natural gas procurement, short- and long-term planning, the ratable hedging program, asset management agreements, and all natural gas asset optimization functions for PECO.

II. <u>PURPOSE OF TESTIMONY</u>

6. Q. What is the purpose of your Direct Testimony in this proceeding?

A. The purpose of my Direct Testimony is to present certain of the information required in Section 1317(a) of the Pennsylvania Public Utility Code (the "Code") (*See* 66 Pa. C.S.A. § 1317(a)) so that the Pennsylvania Public Utility Commission (the "Commission") may make the findings required by Section 1318 of the Code (*See* 66 Pa. C.S.A. § 1318) for a determination that PECO's PGC rates and charges for the historic period (April 1, 2023 through March 31, 2024), the estimated period (April 1, 2024 through November 30, 2024), and the PGC application period (December 1, 2024 through November 30, 2025) are just and reasonable. To that end, I will describe the Company's current hedging program. Additionally, I will discuss PECO's off-system sales sharing mechanism. Finally, I will furnish certain information that PECO committed to provide under the terms of the Joint Petition for Complete Settlement in the 2023 PGC proceeding at Docket No. R-2023-3040285 ("2023 Joint Petition").

7. Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibit SJH-1 which is discussed later in my Direct Testimony.

III. PECO'S HEDGING POLICY

8. Q. Please describe PECO's hedging policy.

A. PECO employs hedging as an additional tool to purchase natural gas on a basis that reasonably ensures system reliability at the least cost. PECO is required to lock-in (*i.e.*, hedge) the price of a minimum volume of its long-term natural gas purchases. This mechanism is designed to mitigate PECO's exposure to natural gas price volatility by locking-in increments of natural gas by preset deadlines so that PECO is not hedging all of its natural gas at the same time under the same market conditions.

9. Q. Please briefly summarize PECO's current Ratable Hedging Program.

A. In the 2016 Joint Petition for Complete Settlement (PGC 33, Docket No. R-2016-2545925), PECO agreed to implement its current "Ratable Hedging Program," which was extended for additional years in the 2017 Joint Petition for Complete Settlement (PGC 34, Docket No. R-2017-2602611), the 2018 Joint Petition for Complete Settlement (PGC 35, Docket No. R-2018-3001568), the 2019 Joint Petition for Complete Settlement (PGC 36, Docket

No. R-2019-3009624), the 2020 Joint Petition for Complete Settlement (PGC 37, Docket No. R-2020-3019661), the 2021 Joint Petition for Complete Settlement (PGC 38, Docket No. R-2021-3025629), the 2022 Joint Petition for Complete Settlement (PGC 39, Docket No. R-2022-3032250), and the 2023 Joint Petition for Complete Settlement (PGC 40, Docket No. R-2023-3040285).

Under this program, PECO hedges approximately 15% of its projected winter purchase volumes. The hedges under the Ratable Hedging Program began in November 2016 and will continue through July 2026. All hedges in this program are made between three (3) and 24 months in advance of the delivery date for the purchased natural gas. In addition, as agreed to in the 2020 Joint Petition, PECO no longer engages in hedging for summer purchases. For convenience, I have attached the current Ratable Hedging Program execution schedule to my Direct Testimony as Exhibit SJH-1.

Finally, pursuant to Paragraphs 19(c) and (d) of the 2016 Joint Petition, the following conditions are applicable to all hedges under the Ratable Hedging Program:

1. PECO will not enter into any individual hedge unless there are at least three qualified respondents to the RFP;

2. Each transaction will be evaluated and compared to current index market indicators, and if the proposed transaction is 10% higher than the indicators, then PECO will not conduct the transaction;

3. PECO will not purchase any of its hedged gas from Transco Zone 4, nor will it use NYMEX Transco Zone 4 basis contract pricing as a market price indicator; and

4. PECO will not make any financial hedges, only hedges of physical gas.

10. Q. Has PECO implemented the Ratable Hedging Program as required? If so, please summarize the results thus far.

A. Yes, during the historic period (April 1, 2023 through March 31, 2024), PECO issued RFPs for six (6) execution periods (these periods are highlighted in yellow in Exhibit SJH-1, with all previous executions appearing in blue). As shown in Table SJH-1 below, for the historic period, PECO has purchased approximately 5.44 MMDTH of hedged natural gas under the program at a weighted average cost of $4.9812 per Dth.

Table SJH-1

Ratable Hedge Program Executed Hedges April 2023 through March 2024				
Execution Month		**DTH**	**$/DTH**	**Total $**
July	2023	1,818,000	$ 5.4372	$ 9,884,850
November	2023	1,812,000	$ 5.4600	$ 9,893,520
March	2024	1,812,000	$ 4.0450	$ 7,329,540
Total		5,442,000	$ 4.9812	$ 27,107,910

11. Q. Is PECO proposing any changes to the Ratable Hedging Program?

A. Yes, PECO is proposing that the Ratable Hedging Program be extended for an additional year. Table SJH-2 below provides the proposed hedging schedule for Year 11:

Table SJH-2

Year 11 Winter			Execution Periods				
	Total Daily	Nov '25	Mar '26	Jul '26	Nov '26	Mar '27	Jul '27
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '27	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '27	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '28	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '28	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '28	36,000	6,000	6,000	6,000	6,000	6,000	6,000

IV. OFF-SYSTEM SALES SHARING MECHANISM

12. Q. Is PECO proposing to extend the Off-System Sales sharing mechanism?

A. Yes. Pursuant to Paragraph 23 of the 2023 Joint Petition, the Off-System Sales sharing mechanism was extended at the 25% rate through November 30, 2026. In this PGC proceeding, PECO is proposing to further extend this mechanism through November 30, 2027.

13. Q. How would PECO's natural gas customers benefit from an extension?

A. An extension will allow the Company to enter into longer term Asset Management Agreements. The Company believes that, under certain conditions, the per-Dth value of transportation and storage capacity released under a longer term arrangement is enhanced and, therefore, can potentially provide a larger reduction in natural gas costs.

V. <u>SETTLEMENT COMMITMENTS</u>

14. Q. Did the 2023 Joint Petition include any settlement commitments for the Ratable Hedging Program?

A. Yes, Paragraph 20 of the 2023 Joint Petition includes certain commitments regarding the Ratable Hedging Program.

15. Q. What does Paragraph 20 of the 2023 Joint Petition provide?

A. Paragraph 20(a) acknowledged that the Company had complied with the requirements of its Ratable Hedging Program for all hedges made through April 2023, and further confirmed that PECO would continue to do so.

Paragraph 20(b) acknowledged the extension of PECO's Ratable Hedging Program for an additional year beyond that which was approved in the 2022 Joint Petition. In addition, Paragraph 20(b) confirmed the removal of summer hedges from PECO's hedging schedule.

16. Q. What did the 2023 Joint Petition require of the Company with respect to Lost and Unaccounted For Gas ("LUFG") monitoring and reporting?

A. Paragraph 22 sets forth the three-year weighted average for the period ending March 31, 2023, and June 30, 2023. The 2023 Joint Petition, however, does not impose any further reporting obligations on the Company as it relates to LUFG. Nonetheless, consistent with its reporting in prior PGC proceedings, PECO has voluntarily provided the LUFG percentages for the period ending March 31, 2024 in Table SJH-3 below, consistent with the methodology set forth in Paragraph 20(c) of the 2015 Joint Petition. The weighted average LUFG for the 36-month period ending June 30, 2024 will be provided when the requisite data becomes available.

Table SJH-3

	Sendout in McF	Billed Sales in Mcf	LUFG
12 Months Ending 3/31/22	88,449,680	84,691,996	4.2%
12 Months Ending 3/31/23	86,824,606	84,280,413	2.9%
12 Months Ending 3/31/24	84,316,700	82,592,318	2.0%
36 Months Ending 3/31/24	259,590,986	251,564,727	3.1%

17. Q. What does the 2023 Joint Petition require with respect to the retainage volume adjustment?

A. Paragraph 19 of the 2023 Joint Petition requires the Company to use a retainage volume adjustment rate for transportation service customers of 3.0% for the twelve months beginning December 1, 2023 and ending November 30, 2024. PECO also agreed that the retainage volume adjustment for the twelve-month period ending November 30, 2024 would be calculated based on the weighted three-year average of LUFG plus the portion of Company-use natural gas attributable to preheater gate station usage for the period ending June 30, 2023. Accordingly, PECO will provide the new retainage rate (and the supporting calculations) for the PGC 41 application period when the data is available, in mid-July 2024.

The Company proposes to continue the agreed upon retainage calculation mechanism for the period ending November 30, 2025.

VI. CONCLUSION

18. Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Ratable Hedging Schedule

Year 7 Winter		**Execution Periods**					
	Total Daily	Nov '21	Mar '22	Jul '22	Nov '22	Mar '23	Jul '23
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '23	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '23	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '24	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '24	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '24	36,000	6,000	6,000	6,000	6,000	6,000	6,000

Year 8 Winter		**Execution Periods**					
	Total Daily	Nov '22	Mar '23	Jul '23	Nov '23	Mar '24	Jul '24
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '24	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '24	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '25	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '25	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '25	36,000	6,000	6,000	6,000	6,000	6,000	6,000

Year 9 Winter		**Execution Periods**					
	Total Daily	Nov '23	Mar '24	Jul '24	Nov '24	Mar '25	Jul '25
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '25	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '25	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '26	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '26	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '26	36,000	6,000	6,000	6,000	6,000	6,000	6,000

Year 10 Winter		**Execution Periods**					
	Total Daily	Nov '24	Mar '25	Jul '25	Nov '25	Mar '26	Jul '26
Delivery Month	Hedged DTH	24 Months Out	20 Months Out	16 Months Out	12 Months Out	8 Months Out	4 Months Out
Nov '26	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Dec '26	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Jan '27	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Feb '27	36,000	6,000	6,000	6,000	6,000	6,000	6,000
Mar '27	36,000	6,000	6,000	6,000	6,000	6,000	6,000

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION
V.
PECO ENERGY COMPANY

Docket No. R-2024-3048767

DIRECT TESTIMONY
OF
JULIE S. DREZNER

PECO STATEMENT NO. 3

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DIRECT TESTIMONY OF JULIE S. DREZNER

I. INTRODUCTION

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

A. My name is Julie S. Drezner. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, PA 19103.

2. Q. What is your educational background?

A. I received a Bachelor of Arts degree from the University of Wisconsin-Madison in 2009. I received a Master of Business Administration degree from Drexel University in 2012.

3. Q. Have you previously submitted testimony in rate proceedings?

A. Yes. I submitted testimony on behalf of PECO Energy Company ("PECO" or the "Company") in the Purchased Gas Cost ("PGC") 40 proceeding.

4. Q. Please describe your work experience relevant to your Direct Testimony.

A. I have been employed by PECO or its affiliate, Exelon Utilities since 2012. I started as a Business Analyst in the Exelon Utilities Planning and Performance group and was promoted to Senior Business Analyst in 2016. In that role, my responsibilities included tracking and compiling a comprehensive analysis of the Exelon utilities' Key Performance Metrics, overseeing Audit Reports, and leading Performance Indicator training sessions. In 2017, I became a Senior Financial Analyst and oversaw the production of the Benchmarking Gas and Electric Source Books for PECO. I managed the collection of data across various benchmarking surveys and represented PECO at industry benchmarking planning and results meetings. In 2020, I became the Senior Business Analyst for the PECO Technical Services Project Management Office.

5. Q. Please identify your current job responsibilities.

A. In my current role as Manager of Energy Supplier Services, I am responsible for oversight of the Gas Cost Accounting function. In addition, I am responsible for managing the financial and service reliability risk of PECO's interstate natural gas transportation and storage contracts through monitoring and actively participating in FERC proceedings. Lastly, I manage certain aspects of both PECO's High Volume Transportation ("HVT") and Low Volume Transportation ("LVT") Gas Choice programs.

II. <u>PURPOSE OF TESTIMONY</u>

6. Q. What is the purpose of your Direct Testimony in this proceeding?

A. The purpose of my Direct Testimony is to present certain of the information required in Section 1317(a) of the Pennsylvania Public Utility Code (the "Code") (*see* 66 Pa. C.S.A. § 1317(a)) so that the Pennsylvania Public Utility Commission (the "Commission") may make the findings required by Section 1318 of the Code (*see* 66 Pa. C.S.A. § 1318) for a determination that PECO's PGC rates and charges for the historic period (April 1, 2023 through March 31, 2024), the estimated period (April 1, 2024 through November 30, 2024), and the PGC application period (December 1, 2024 through November 30, 2025) are just and reasonable. To that end, I will describe the Company's natural gas purchase policies and practices, including PECO's use of natural gas pipeline transportation and storage contracts, and explain its HVT Gas Choice program.

7. Q. Are you sponsoring any exhibits?

A. Yes. I am sponsoring Exhibits JSD-1 and JSD-2, which are discussed later in my Direct Testimony.

III. THE BALANCING CHARGE

8. Q. Is the Company proposing a change to the balancing charge rate in this case?

A. Yes. Under the terms of the Settlement of the Company's 2008 Gas Distribution Base Rate Case at Docket No. R-2008-2028394, the Company is required to update the balancing charge as part of its annual 1307(f) filing. Pursuant to the terms of the 2020 Joint Petition for Complete Settlement in the PGC 37 proceeding (Docket No. R-2020-3025629), the balancing charge calculation was revised to include: (i) the costs associated with the interstate pipeline transportation arrangements required to deliver natural gas to and from storage; and (ii) aggregate daily HVT imbalances experienced during the summer months, as opposed to only the winter months as was the historical practice. As shown in Exhibit JSD-1 accompanying my Direct Testimony, the Company is proposing a balancing charge of $0.0225 per Mcf to become effective on December 1, 2024, which is $0.0022 less per Mcf than the currently effective balancing charge.

9. Q. Why did the balancing charge decrease by $0.0022 per Mcf?

A. Please refer to Exhibit JSD-2, which provides the calculations used to establish the current balancing charge and the proposed balancing charge, along with a line-by-line comparison showing the changes between the two. The decrease is driven by deviations in a number of different factors, including slightly decreased storage costs.

IV. PECO'S NATURAL GAS PURCHASE POLICIES AND PRACTICES

10. Q. Has PECO continued its evaluation of participation in pipeline open seasons as a way of securing additional cost-effective Firm Transportation to PECO's City Gate?

A. Yes. PECO continues to evaluate pipeline open seasons and capacity made available via permanent capacity releases to see if any new, cost-effective, firm natural gas transportation source to PECO's city gate became available. In general, each opportunity is analyzed to determine whether PECO's participation in the project is needed to meet projections for increased firm demand, or if the project offers a reliable least-cost alternative to an existing transportation or storage contract approaching its expiration date. In addition, projects are reviewed to determine: (1) their ability to deliver firm natural gas from a reliable, liquid market to PECO; and (2) if they are compatible with PECO's existing contracts and load profile.

The Regional Energy Access ("REA") project was referred to as Project X in Company Witness Carlos Thillet's Direct Testimony submitted in support of PECO's prior PGC proceedings – PGC 36, PGC 37, and PGC 38, and was also discussed in Company Witness Scott J. Hughes' Direct Testimony in support of PGC 39 and my Direct Testimony in support of PGC 40. On February 10, 2020, PECO executed a Precedent Agreement with Transco for 100,000 Dth/day of REA capacity. The firm transportation capacity will enable PECO to move natural gas from receipt points in the Leidy Pennsylvania Marcellus Shale production area to delivery points on PECO's distribution system. The initial term is for 15 years. The capacity will provide PECO with a least-cost, reliable, source of supply enabling the Company to meet its firm demand by reducing the delivered supply needed to eliminate the peak-day supply gap, while providing deliveries to PECO gate stations and further eliminating exposure to market area price volatility. Transco filed its 7(c) FERC Application on March 26, 2021. Subsequently, on April 28, 2021, Exelon Corporation filed comments in support of the REA application. A portion of the REA Project is now in service and the additional contracted amount is scheduled to be placed into service in 2024 and will provide PECO with 100,000 Dth/day of Firm Capacity from the Leidy Marcellus production area to PECO's City gate. On February 17, 2023, PECO executed a Service Agreement with Transco for 100,000 Dth/day of REA capacity. PECO negotiated an early in-service contract for 32,922 Dth/day of the 10,000 Dth/day REA firm capacity, effective October 1, 2023 for one year.

PECO also submitted two non-binding bids on open seasons in 2023. PECO submitted one bid for 22,500 Dth/day north-zone capacity on Adelphia for $0.0864 per MMBTU per day on September 19, 2023. PECO submitted the other bid was for 3,687,492 MSQ in Dth storage capacity on Mississippi Hub for $0.031 storage reservation charge in $/Dth/Month on November 9, 2023. The Mississippi Hub bid was an attempt to duplicate WSS storage, as discussed in the response to Question 12. Neither of PECO's submitted bids were selected.

11. Q. Did participation in PECO's LVT Gas Choice program continue to grow for the 12-month period ending March 31, 2024?

A. As indicated in Table JSD-1 below, PECO's LVT Gas Choice program continues to be robust. The number of customers in the program has typically increased year-over-year; however, for the 12-month period ending March 31, 2024 participation increased slightly. In addition, the number of suppliers decreased during this period from 60 to 59. PECO expects strong participation in this program to continue.

Table JSD-1

12-Month Period Ending March 31	Customers participating in LVT program	YOY Change	Aggregate Daily Delivery Quantity	Aggregate Daily Contract Quantity
2015	80,410	-	46,887	55,748
2016	81,088	0.80%	46,896	58,573
2017	81,472	0.50%	46,481	60,324
2018	84,161	3.30%	60,951	60,920
2019	95,293	13.20%	66,786	66,760
2020	105,312	10.50%	74,190	74,166
2021	96,625	-8.20%	70,841	70,841
2022	89,563	-7.30%	66,013	66,013
2023	83,504	-6.80%	64,743	64,743
2024	84,024	0.60%	67,178	67,178

V. FIRM INTERSTATE PIPELINE CONTRACTS

12. Q. Please identify the firm interstate natural gas pipeline service agreements that have been subject to renewal since PECO's last PGC proceeding (PGC 40) and that remain in effect.

A. Table JSD-2 below lists the storage and transportation service agreements that were subject to renewal/termination notice during the past year and identifies whether PECO opted to renew each agreement. All renewed contracts are listed below. The Early In-Service REA contract was not renewed and is being replaced with the full REA 100,000 Dth/day capacity contract as discussed in the response to Question 10. The WSS Storage contract was not renewed and is being replaced by WSS

Market Based Rates ("MBR"). For a description of the WSS MBR proceedings, please see the response to Question 15.

<u>Table JSD-2</u>

Pipeline Contract	Earliest Termination Date	Notice Period	Renewed (Yes or No)
Texas Eastern			
FT-1 Transportation	10/31/2026	24 Months	Yes
CDS Transportation	10/31/2026	24 Months	Yes
FT-1 Phila Lateral	10/31/2029	60 Months	Yes
FT-1 Phila Flex X	10/31/2029	60 Months	Yes
FT-1 Transportation ELA	10/31/2025	12 Months	Yes
FTS-2 Transportation	3/31/2026	12 Months	Yes
FTS-7 Transportation	4/15/2027	24 Months	Yes
FTS-8 Transportation	4/15/2027	24 Months	Yes
FTS Transportation	3/31/2027	24 Months	Yes
SS-1 Storage	4/30/2027	24 Months	Yes
Transco			
FT Transportation	3/31/2028	36 Months	Yes
FT Transportation	7/31/2027	36 Months	Yes
FT - Leidy	10/31/2026	24 Months	Yes
FT - Trenton Woodbury	10/31/2026	24 Months	Yes
WSS Storage	3/31/2025	12 Months	No
S-2 Storage	3/31/2026	12 Months	Yes
Early In Service REA	10/01/2024	12 Months	No
Eastern Gas Transmission & Storage, Inc.			
GSS Storage	3/31/2027	24 Months	Yes
UGI			
XD Firm	12/01/2025	12 Months	Yes

13. Q. Why did PECO choose to allow the contracts identified above to evergreen for an additional term?

A. First, PECO continues to require the above-mentioned services primarily to satisfy the temperature-sensitive demands of both its retail sales customers and its Gas Choice customers for whom PECO is the supplier of last resort ("SOLR").

Second, each of these agreements is designed to provide satisfactory capacity to transport the natural gas supplies needed to serve the demand of PECO's retail sales customers, especially during the winter period. As the SOLR, PECO also needs these contracts to serve Gas Choice customers that may return to PECO for supply during the winter period. PECO has not yet discovered a more economical alternative to continuing these contracts.

Third, consistent with the settlement of PECO's natural gas restructuring proceeding at Docket No. R-00994787, on June 5, 2023 and November 29, 2023, PECO issued RFPs for its firm storage and transportation contracts. The RFPs were sent to Pennsylvania NGSs, including Gas Choice Suppliers participating in PECO's Gas Choice programs, interstate pipeline companies and others. In response to the RFPs, interested parties were given the opportunity to provide a contract service as a replacement to service provided by the pipeline supplier. None of the responses received provided a more cost-effective alternative to the contracts listed in Table JSD-2 above.

14. Q. By what means other than the RFP process did PECO try to obtain comparable services at a lower cost than the existing services?

A. PECO regularly reviews all pipeline open seasons (*see* Question 10) to assess opportunities for new and replacement services. PECO also entered two open season which were not accepted (*see* Question 10). Additionally, PECO regularly contacted pipeline representatives to discuss its supply portfolio needs and to explore potentially less costly options to existing services. Despite these efforts, PECO could not obtain any comparable replacement services at a lower cost than the existing services. Therefore, it is necessary for PECO to retain these agreements as part of its overall capacity portfolio to satisfy the demand requirements of its retail sales and Gas Choice customers.

15. Q. Please explain how PGC customers benefit from PECO's active participation in the recent FERC rate case proceedings.

A. Please review Section 5 of the Advance Filing for a list of PECO's active involvement in FERC cases. PECO's active participation in the FERC rate case proceedings benefit PECO's PGC customers by achieving settlement rates that are less than the increases sought in the as-filed rates, resulting in smaller rate increases for PECO and its PGC customers. I provide a brief explanation the WSS MBR proceedings below.

WSS: PECO renewed and extended the WSS contract listed in Table JSD-2. In 2021, Transco filed for MBR authority for Rate Schedule WSS, which as originally proposed, would increase costs for the service by 140% to be effective on April 1, 2025. PECO and the WSS Customer Group protested and challenged

Transco's proposal in Dockets RP21-1143 and RP23-840. Despite the challenges of the WSS Customer Group, in 2022 and upon rehearing in 2023, FERC found the MBR to be just and reasonable. The WSS Customer Group appealed the decisions to the United States Court of Appeals for the District of Columbia Circuit. In 2023, after receiving the decision on rehearing affirming the MBR from FERC, Transco filed new General Terms and Conditions for the storage service with the Commission.

PECO provided data showing that Requests for Proposal were sent out on two occasions (*see* the response to Question 13) trying to replicate the WSS service, but that no licensed supplier in the Commonwealth of Pennsylvania responded. PECO also responded to an Open Season from Mississippi Hub Storage for a Market Based Rate storage equivalent for WSS, as referenced in the response to Question 10. The storage was similarly located to WSS, interconnected with Transco in Zone 4. PECO's bid was not accepted. PECO also submitted an affidavit as part of the WSS Customer Group protest in Docket RP23-840. FERC determined that these facts along with other issues warranted a Technical Conference on September 13, 2023. The parties reached a settlement in the proceeding that would increase WSS rates by 124% over a ten-year period and allow market-based rates.

PECO performed a cost analysis of the proposal and reviewed the analysis of outside consultants, ultimately finding the 124% cost increase to be a discount compared to the open market for storages interconnected with the Transco system. PECO elected to extend the WSS MBR agreement with the 10-year storage and commodity storage deal, in order to provide the lowest increase in fixed costs to PGC customers.

Tetco has notified LDCs of the intention to initiate a prefiling for a Section 4 Rate Case settlement in lieu of a Section 4 Rate Case. The settlement has not yet been finalized. However, parties have tentatively reached a settlement for all issues as of May 3, 2024. This settlement has not yet been approved by FERC.

Transco is planning to file a Section 4 Rate Case on or before August 30, 2024. PECO will continue to actively participate in all relevant FERC proceedings to achieve the best possible rates and reliability services for the PGC customers.

VI. <u>HVT GAS CHOICE PROGRAM INFORMATION</u>

16. Q. Please describe the HVT Gas Choice program.

A. Under PECO's HVT Gas Choice program, large commercial and industrial customers may purchase natural gas from an NGS for transport on the PECO system. The rules of the HVT Gas Choice program are set forth in PECO's Natural Gas Service Tariff.

17. Q. Did the Advance Information contain any information regarding the HVT Gas Choice program?

A. Yes, certain information regarding the HVT Gas Choice program was included in Sections 10 through 12 of the Advance Information.

18. Q. What information is contained in Section 10 of the Advance Information?

A. Section 10 of the Advance Information includes a copy of the PECO Gas Transportation Service Agreement form for large commercial and industrial customers electing to participate in the HVT Gas Choice program.

19. Q. What information is provided in Sections 11 and 12 of the Advance Information?

A. Section 11 of the Advance Information includes a report reflecting specific contract information for each HVT Gas Choice customer. Specifically, the following information is provided for each customer: the customer's rate, size category (greater than or less than 18,000 Mcf per year), daily transportation contract quantity, firm stand-by sales quantity, if any, and commodity rate. Section 12 of the Advance Information provides the monthly transportation volume for each transportation customer for each month beginning April 1, 2023 and ending March 31, 2024. Specifically, the following information is provided for each customer: the customer's rate; total monthly deliveries in Mcf; and total transportation deliveries. Because this information is voluminous, PECO does not file it with the Advance Information but will provide it upon request.

VII. CONCLUSION

20. Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Exhibit JSD-1

2024 Balancing Charges

Annual Cost for Storage (PECO PGC 40, Section 7, Page 1)					$ 31,570,000
Aggreate Imbalances for TS Customers					
	Aggregate Daily Excess Deliveries	Aggregate Daily Deficient Deliveries			
Dec-22	52,041	73,244			
Jan-23	31,278	52,746			
Feb-23	73,799	69,655			
Mar-23	41,223	50,508			
Apr-23	52,378	43,910			
May-23	46,324	34,833			
Jun-23	25,815	40,097			
Jul-23	44,433	45,471			
Aug-23	34,311	56,079			
Sep-23	20,843	71,704			
Oct-23	27,168	69,714			
Nov-23	47,044	87,971			
Total	496,657	695,932			
Total Aggregate 12 Month Daily TS Imbalance in MCF					1,192,589
Projected Annual PGC Volume in MCF					68,253,410
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)					1.75%
Annual Storage Cost Applicable to Transportation Customers					
1.75% of		$ 31,570,000			$ 551,621
Revenue From Excess Delivery Penalty Charge for Dec 22 through Nov 23 in mcf			76,105	$ 0.25	$ 19,026.25
Calculation of the Proposed Adjusted Balancing Charges					
Storage Cost applicable to Transportation Customers					$ 532,595
Divided by TS MCF Actual Dec 22 through Nov 23					23,652,714
Balancing Charge per MCF					$ 0.0225

2024 Balancing Charges Exhibit JSD-2

Annual Cost for Storage (PECO PGC 40, Section 7, Page 1)

Fixed Storage Costs (includes associated transport)	$ 31,570,000
Storage Injection Cost	$ -
Storage Withdrawl Cost	$ -
Total	$ 31,570,000

Aggreate Imbalances for TS Customers

	Aggregate Daily Excess Deliveries	Aggregate Daily Deficient Deliveries
Dec-22	52,041	73,244
Jan-23	31,278	52,746
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May-23	46,324	34,833
Jun-23	25,815	40,097
Jul-23	44,433	45,471
Aug-23	34,311	56,079
Sep-23	20,843	71,704
Oct-23	27,168	69,714
Nov-23	47,044	87,971
Total	496,657	695,932

Total Aggregate 12 Month Daily TS Imbalance in MCF					1,192,589
Projected Annual PGC Volume in MCF					68,253,410
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)					1.75%
Annual Storage Cost Applicable to Transportation Customers					
1.75%	of	$ 31,570,000			$ 551,621
Revenue From Excess Delivery Penalty Charge for Dec 22 through Nov 23 in mcf			76,105	$ 0.25	$ 19,026.25
Calculation of the Proposed Adjusted Balancing Charges					
Storage Cost applicable to Transportation Customers					$ 532,595
Divided by TS MCF Actual Dec 22 through Nov 23					23,652,714
Balancing Charge per MCF					$ 0.0225

2023 Balancing Charges Exhibit JSD-2

Annual Cost for Storage (PECO PGC 39, Section 7, Page 1)

Fixed Storage Costs (includes associated transport)	$ 35,723,000
Storage Injection Cost	$ -
Storage Withdrawl Cost	$ -
Total	$ 35,723,000

Aggreate Imbalances for TS Customers

	Aggregate Daily Excess Deliveries	Aggregate Daily Deficient Deliveries
Dec-21	107,360	40,483
Jan-22	25,772	83,178
Feb-22	58,828	56,218
Mar-22	66,142	77,118
Apr-22	50,275	24,407
May-22	34,645	28,901
Jun-22	32,686	43,181
Jul-22	29,319	46,170
Aug-22	32,374	28,794
Sep-22	31,940	57,468
Oct-22	27,143	46,136
Nov-22	72,179	64,499
Total	568,663	596,553

Total Aggregate 12 Month Daily TS Imbalance in MCF					1,165,216
Projected Annual PGC Volume in MCF					65,471,348
Percentage of Storage Cost applicable to PGC customers (Agg Imbal/projected vol)					1.78%
Annual Storage Cost Applicable to Transportation Customers					
1.78%	of	$ 35,723,000			$ 635,774
Revenue From Excess Delivery Penalty Charge for Dec 21 through Nov 22 in mcf			83,004	$ 0.25	$ 20,751.00
Calculation of the Proposed Adjusted Balancing Charges					
Storage Cost applicable to Transportation Customers					$ 615,023
Divided by TS MCF Actual Dec 21 through Nov 22					24,865,821
Balancing Charge per MCF					$ 0.0247

PECO STATEMENT NO. 4

BEFORE THE

PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION

V.

PECO ENERGY COMPANY

DOCKET NO. R-2024-3048767

DIRECT TESTIMONY

OF

ANTHONY P. DIFELICE

Table of Contents

DIRECT TESTIMONY OF ANTHONY P. DIFELICE

I. INTRODUCTION

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

A. My name is Anthony P. DiFelice. My business address is PECO Energy Company, 2301 Market Street, Philadelphia, PA 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 Senior Engineer in the Retail Rates Division.

3. Q. Please describe your educational background.

A. I graduated from the University of Pennsylvania in 1981 with a Bachelor of Applied Science degree from the School of Engineering and Applied Science. I obtained a Master of Business Administration degree with a concentration in Finance from Drexel University in 1989.

4. Q. Please describe your employment history with PECO.

A. I began working for PECO in January of 1982. Since that time, I have been employed in the Rates area of the Company, currently known as Retail Rates. Among other responsibilities, my duties include the calculation of the rate for the Purchased Gas Cost ("PGC") adjustment.

5. Q. Have you previously submitted testimony in rate proceedings?

A. Yes. I submitted testimony on behalf of the Company in the following proceedings:

a. PGC No. 18 at Docket No. R-00016366;

b. PGC No. 19 at Docket No. R-00027391;

c. PGC No. 20 at Docket No. R-00038409;

d. PGC No. 21 at Docket No. R-00049423;

e. PGC No. 22 at Docket No. R-00050537;

f. PGC No. 23 at Docket No. R-00061501;

g. PGC No. 24 at Docket No. R-00072331;

h. PGC No. 26 at Docket No. R-2009-2108705;

i. PGC No. 27 at Docket No. R-2010-2174034;

j. PGC No. 28 at Docket No. R-2011-2239263;

k. PGC No. 29 at Docket No. R-2012-2302784;

l. PGC No. 30 at Docket No. R-2013-2363227;

m. PGC No. 31 at Docket No. R-2014-2420283;

n. PGC No. 32 at Docket No. R-2015-2480969;

o. PGC No. 33 at Docket No. R-2016-2545925;

p. PGC No. 34 at Docket No. R-2017-2602611;

q. PGC No. 35 at Docket No. R-2018-3001568;

r. PGC No. 36 at Docket No. R-2019-3009624;

s. PGC No. 37 at Docket No. R-2020-3019661;

t. PGC No. 38 at Docket No. R-2021-3025629;

u. PGC No. 39 at Docket No. R-2022-3032250; and

v. PGC No. 40 at Docket No. R-2023-3040285.

In addition, I submitted testimony in the Company's proceeding, regarding the determination of the Gas Procurement Charge ("GPC"), at Docket No. P-2012-2328614, in compliance with the Pennsylvania Public Utility Commission's (the

"Commission") Order for Promotion of Competitive Retail Markets at Docket No. L-2008-2069114.

II. PURPOSE OF TESTIMONY

6. Q. What is the purpose of your Direct Testimony?

A. My Direct Testimony will describe and support the development of the PGC rates filed by the Company in this proceeding, PGC No. 41, to become effective December 1, 2024. Pursuant to the Company's Gas Restructuring Settlement, filed and approved at Docket No. R-00994787, the PGC rate is unbundled into the Sales Service Cost ("SSC") and the Balancing Service Cost ("BSC"). The SSC is a charge to those customers purchasing natural gas supply from PECO. The BSC recovers costs associated with the operations of contract storage facilities and PECO's peaking services from all of PECO's low-volume customers, whether they purchase their natural gas supply from PECO or from a competitive natural gas supplier. Low-volume customers are defined as customers taking service under Rate Schedules GR, CAP, GC, OL, L and MV-F.

My Direct Testimony also will provide the monthly demand charge for Rate TS (Transportation Service) standby sales service to become effective December 1, 2024.

III. EXHIBITS SPONSORED

7. Q. Please identify the exhibits you are sponsoring in this proceeding.

A. I am sponsoring the following exhibits:

- Exhibit APD-1 is a table comparing the Company's current PGC No. 40Q1 rates, effective on March 1, 2024, with the proposed PGC No. 41 rates, effective December 1, 2024.

- Exhibit APD-2 provides the development of the Merchant Function Charge ("MFC") for the applicable rate classes for the proposed December 1, 2024 PGC rates as well as the total PGC rates for the applicable rate classes.
- Exhibit APD-3 summarizes the computation of the PGC No. 41 SSC, exclusive of the MFC.
- Exhibit APD-4 summarizes the computation of the PGC No. 41 BSC.

Also included in my Direct Testimony as Exhibit APD-5 are the following pages, in both regular text and "redlined" versions, of PECO's proposed Supplement No. 15 to Tariff Gas – Pa. P.U.C. No. 5 ("Supplement No. 15"):

- 14th revised Page No. 1 and 14th revised Page No. 2.
- 7th revised Page Nos. 43 and 49, reflecting a $0.0549 per Mcf total increase in the Section 1307(f) rates for Rates GR and CAP, a $0.0552 per Mcf total increase for Rate GC and a $0.0552 per Mcf total increase for Rates OL, L and MV-F.
- 4th revised Page No. 44, extending the Off-System Sales Sharing Mechanism through November 30, 2027.
- 7th revised Page Nos. 47 and 48, reflecting the Merchant Function Charge and the Price to Compare.
- 4th revised Page No. 71, reflecting a $0.0022 per Mcf decrease in the Transportation Balancing Charge to a value of $0.0225 per Mcf.

IV. PROPOSED PGC RATES

8. Q. Please identify the specific time periods relevant to this filing.

A. The period December 1, 2023 through April 30, 2024 reflects actual data and the period May 1, 2024 through November 30, 2024 reflects projected data and together comprise the "E" factor period. The "C" factor period, or PGC No. 41 application period, begins December 1, 2024 and ends November 30, 2025.

9. Q. Did you prepare Exhibits APD-1, 2, 3, 4 and 5 identified above?

A. Yes. In addition, the natural gas cost information previously filed by the Company on April 30, 2024 in support of PGC 41 (the "Advance Information") is sponsored by Company Witness Suzette E. Adams, who is submitting PECO Statement No. 1. Similarly, the proposed extension of the Off-System Sales Sharing Mechanism is sponsored by Company Witness Scott J. Hughes, who is submitting PECO Statement No. 2. Finally, the determination of the Transportation Balancing Charge is sponsored by Company Witness Julie S. Drezner, who is submitting PECO Statement No. 3.

10. Q. Please summarize how the Company recovers its projected cost of purchased natural gas and prior period over/under collections through current rates.

A. As set forth in its tariff, the Company recovers the projected cost of purchased natural gas and natural gas procurement charges through the Commodity Charge ("CC") factor of the SSC and the "C" factor of the BSC. In addition, amounts for prior period over/under collections, refunds, interest and other items are recovered through the GCA of the SSC and the "E" factor of the BSC. In total, under PGC No. 40, which was approved by the Commission at Docket No. R-2023-3040285, the Company began recovering \$4.2401 per Mcf for Rates GR and CAP, \$4.2278 per Mcf for Rate GC and \$4.2239 per Mcf for Rates OL, L and MV-F as the bundled SSC and BSC charges applicable to its retail sales service as of December 1, 2023. These amounts were updated by a February 28, 2024 filing for PGC No. 40-Q1 that put into effect, as of March 1, 2024, PGC rates of \$4.7578 per Mcf for Rates GR and CAP, \$4.7450 per Mcf for Rate GC and \$4.7411 per Mcf for Rates OL, L and MV-F.

11. Q. Please describe the MFC and its impact on the June 1, 2024 PGC rate.

A. As a result of the Commission's Order at Docket No. P-2012-2328614,[1] an MFC was created separately for Rates GR and CAP and Rate GC. The charge recovers uncollectible charge-offs related to natural gas supply from PGC customers who procure their natural gas supply from PECO. It is currently based on write-off factors of 0.42% for Rates GR and CAP and 0.13% for Rate GC and 0.04% for Rates OL, L and MV-F. These write-off factors are from the Commission's Final Order in PECO's 2022 Gas Distribution Base Rate Case at Docket No. R-2022-3031113. The write-off factors are applied to the CC, including the GPC portion of the PGC rate, to produce the applicable MFCs. Subsequently, the MFCs are included in the CC portion of the SSC. The MFC charges initially became effective on June 1, 2015.

These MFCs will change with PGC rate changes due to the changing CC, including GPC charges, and are not reconcilable. As a result of the different MFCs and the subsequent different CCs, the PGC rates will have different values depending on the applicable rate classes. Specifically, the March 1, 2024 value of the MFC is $0.0185 per Mcf for Rates GR and CAP, $0.0057 per Mcf for Rate GC and $0.0018 per Mcf for Rates OL, L and MV-F. This leads to a March 1, 2024 total CC value of $4.4203 per Mcf for Rates GR and CAP, $4.4075 per Mcf for Rate GC and $4.4036 per Mcf for Rates OL, L and MV-F (*see* Table APD-1, below).

[1] *Petition of PECO Energy Company – Gas Division – Pursuant to 66 Pa. C.S. 1308(a) For Approval of its Proposed Tariff Revisions,* Docket No. P-2012-2328614, Order (Issued April 18, 2013).

Table APD-1

	Rates GR and CAP ($/Mcf)	**Rate GC ($/Mcf)**	**Rates OL, L and MV-F ($/Mcf)**
CC including GPC	$4.4018	$4.4018	$4.4018
MFC	$0.0185	$0.0057	$0.0018
Total CC including GPC and MFC **Effective March 1, 2024**	$4.4203	$4.4075	$4.4036

The March 1, 2024 GCA credit value of ($0.0468) per Mcf is the same for Rates GR, CAP, GC, OL, L and MV-F. The March 1, 2024 BSC of $0.3843 per Mcf is also the same for these rates. The resultant PGC rates are shown below in Table APD-2.

Table APD-2

	Rates GR and CAP ($/Mcf)	**Rate GC ($/Mcf)**	**Rates OL, L and MV-F ($/Mcf)**
CC	$4.4203	$4.4075	$4.4036
GCA	($0.0468)	($0.0468)	($0.0468)
BSC	$0.3843	$0.3843	$0.3843
Total PGC Rate **Effective March 1, 2024**	$4.7578	$4.7450	$4.7411

12. Q. How does the MFC impact the December 1, 2024 PGC No. 41 rate?

A. The PGC rates will differ, depending on the applicable tariff rate class. Exhibit APD-2 shows the derivation of the proposed December 1, 2024 PGC rates.

The write-off factors for uncollectible charge-offs are applied to the December 1, 2024 CC, including the GPC, to yield an MFC (effective December 1, 2024) of $0.0181 per Mcf for Rates GR and CAP, $0.0056 per Mcf for Rate GC and $0.0017 per Mcf for Rates OL, L and MV-F. As a result, the total December 1, 2024 CC, including the GPC and MFC, is $4.3386 per Mcf for Rates GR and CAP, $4.4.3261 per Mcf for Rate GC and $4.3222 per Mcf for Rates OL, L and MV-F as shown below in Table APD-3 and in Exhibit APD-2.

Table APD-3

	Rates GR and CAP ($/Mcf)	**Rate GC ($/Mcf)**	**Rates OL, L and MV-F ($/Mcf)**
CC including GPC	$4.3205	$4.3205	$4.3205
MFC	$0.0181	$0.0056	$0.0017
Total CC including GPC and MFC **Effective December 1, 2024**	$4.3386	$4.3261	$4.3222

Note that the GPC and the write-off factors for the MFC calculation will be updated based on the Commission's final determination in PECO's 2024 natural gas distribution base rate case at Docket No. R-2024-3046932 (the "2024 Gas Base Rate Case"). The effective date of rates for the 2024 Gas Base Rate Case is anticipated to be on January 1, 2025.

13. Q. Please describe the rates proposed for PGC No. 41 effective December 1, 2024.

A. Adding the GCA value of $0.1493 per Mcf and the BSC of $0.3248 per Mcf to the above total CC values produces PGC rates effective December 1, 2024, of $4.8127 per Mcf for Rates GR and CAP, $4.8002 per Mcf for Rate GC and $4.7963 per Mcf for Rates OL, L and MV-F as shown below in Table APD-4 and in Exhibit APD-2.

Table APD-4

	Rates GR and CAP ($/Mcf)	Rate GC ($/Mcf)	Rates OL, L and MV-F ($/Mcf)
CC	$4.3386	$4.3261	$4.3222
GCA	$0.1493	$0.1493	$0.1493
BSC	$0.3248	$0.3248	$0.3248
Total PGC Rate Effective **December 1, 2024**	$4.8127	$4.8002	$4.7963

14. Q. Please summarize the differences between the PGC No. 41 and the PGC No. 40-Q2 rates.

A. The CC component of the SSC, exclusive of the MFC, is projected to decrease by $0.0817 per Mcf, from $4.4018 per Mcf in PGC No. 40-Q1 to $4.3205 per Mcf in PGC No. 41. The GCA reconciliation component of the SSC will increase from a credit value of ($0.0468) per Mcf in PGC No. 40-Q1 to a value of $0.1493 per Mcf in PGC No. 41. Lastly, the BSC will decrease from $0.3843 per Mcf to $0.3248 per Mcf.

15. Q. Please explain what caused the CC component of the SSC, exclusive of the MFC, to decrease from $4.4018 per Mcf in PGC No. 40-Q1 to $4.3205 per Mcf in PGC No. 41.

A. The $4.3205 per Mcf value of the CC, exclusive of the MFC, for PGC No. 41 is comprised of two parts. The first component is the projected recoverable fuel cost of $291.9 million for the period December 1, 2024 through November 30, 2025 divided by twelve-month projected sales of 68,167,987 Mcf's for the same period, which equates to $4.2819 per Mcf. In addition, a GPC of $0.0386 per Mcf is included in the

CC component. The calculation of the $4.4018 per Mcf CC rate, exclusive of the MFC, for PGC No. 40-Q1 reflects a value of $4.3632 per Mcf for the combination of actual and projected fuel costs and certain over/under collection data for the period December 1, 2023 through November 30, 2024.[2] The CC rate also includes the same GPC value of $0.0386 per Mcf.

16. Q. Please explain what caused the GCA rate to increase from a credit value of ($0.0468) per Mcf in PGC No. 40-Q1 to a value of $0.1493 per Mcf in PGC No. 41.

A. The $0.1961 per Mcf increase in the GCA rate is due to four factors. First, there was a change in the over/under collection component for the commodity cost, from a $13.8 million under-collection balance as of November 30, 2023, reflected in the PGC No. 40-Q1 rate, to a projected $9.1 million under-collection balance as of November 30, 2024, which is to be collected from customers during the PGC No. 41 application period.

Second, there was a change in the accompanying interest balance from a $0.5 million under-collection balance as of November 30, 2023, reflected in the PGC No. 40-Q1 rate, to a projected $0.7 under-collection balance as of November 30, 2024, which is to be recovered from customers during the PGC No. 41 application period.

Third, there was a decrease in the balance for supplier refunds, including interest, from an over-collection balance of $16.5 million as of November 30, 2023, reflected in the PGC 40-Q2 rate, to a projected over-collection balance of $2.3 million

[2] This was calculated in accordance with the PGC quarterly calculation methodology approved in the Company's PGC No. 20 proceeding at Docket No. R-00038409.

as of November 30, 2024. Finally, the balance of Rate IS (Interruptible Service) profit has changed from an over-collection balance of $869 as of November 30, 2023, to a projected over-collection balance of $1,219 as of November 30, 2024. The changes in interest and supplier refunds act to increase the GCA rate. The changes in the commodity cost under-collection and interest, supplier refund and the Rate IS profit balance act to decrease the GCA rate.

17. Q. Please explain what caused the BSC rate to decrease from $0.3843 per Mcf in PGC No. 40-Q1 to $0.3248 per Mcf for PGC No. 41.

A. The portion of the total BSC rate for PGC No. 41 associated with contract storage and peaking services of $0.3874 per Mcf is based on a projected recoverable cost of $26.4 million for the period December 1, 2024 through November 30, 2025, divided by twelve-month projected sales of 68,167,987 Mcf's for the same period. The associated value of $0.4498 per Mcf for PGC No. 40-Q1 reflects a combination of actual and projected costs and certain over/under-collection data for the period December 1, 2023 through November 30, 2024.[3] This change caused a decrease of $0.0624 per Mcf in the BSC rate for PGC No. 41.

The combination of changes for over/under-collection balances for various items of the BSC rate act to increase the BSC rate by $0.0029 per Mcf. The over/under-collection balance associated with contract storage and peaking services changed from a $2.3 million over-collection balance as of November 30, 2023, to a projected over-

[3] This was calculated in accordance with the PGC quarterly calculation methodology approved in the Company's PGC No. 20 proceeding at Docket No. R-00038409.

collection balance of $2.6 million as of November 30, 2024. In addition, the over-collection balance for miscellaneous surcharge monies decreased from $1.2 million as of December 1, 2023, to a projected over-collection balance of $1.0 million as of November 30, 2024. Lastly, the net interest balance changed from an over-collection balance of $0.7 million as of November 30, 2023, to a projected over-collection balance of $0.6 million as of November 30, 2024.

V. SALES SERVICE COST COMPONENTS

18. Q. Please describe the information shown in Exhibit APD-1.

A. Exhibit APD-1 is a single sheet titled "Proposed Changes in PGC Rate Prices Effective December 1, 2024." This sheet consists of three columns, the first of which shows the unbundled rates effective March 1, 2024, from PGC No. 40-Q1. The second column shows the proposed changes to the PGC No. 40-Q1rates. The third column is the sum of Columns 1 and 2 and shows the PGC No. 41 proposed rates set forth in Supplement No. 15, which are to become effective on December 1, 2024. Exhibit APD-1 shows a total increase of $0.0549 per Mcf between the proposed PGC No. 41 rates and current PGC No. 40-Q1 rates for Rates GR and CAP, a total increase of $0.0552 per Mcf for Rate GC and a total increase of $0.0552 per Mcf for Rates OL, L and MV-F.

19. Q. Please describe the information shown in Exhibit APD-2.

A. Exhibit APD-2 provides the development of the MFC and its effect on the CC by rate class for the PGC No. 41 rate to be effective December 1, 2024. In addition, the GCA and BSC are included to determine the total PGC No. 41 rates by rate class to be effective December 1, 2024.

20. Q. Please describe the information shown on page 1 of Exhibit APD-3, which develops the SSC, exclusive of the MFC, for PGC No. 41 to be effective December 1, 2024.

A. Exhibit APD-3, page 1, summarizes the projected cost of natural gas, the GPC and details of the experienced net under-collection ("E" factor or GCA). Page 1, line 1, shows the allocated projection of the commodity cost of natural gas of $291,890,012 and the associated rate of $4.2819 per Mcf.

In addition, as a result of the Commission's Order at Docket No. R-2022-3031113, the Company's 2022 gas distribution base rate case, a GPC of $0.0386 per Mcf, to recover procurement-related costs including labor, pensions, benefits, outside legal, information technology and working capital, is shown on page 1, line 1. It is applied to PGC customers who obtain natural gas supply from PECO. This charge is included in the calculation of the CC portion of the SSC for PGC No. 40-Q1 and the proposed PGC No. 41. The charge is not reconcilable and will remain constant until the next distribution base rate case.

Note that the GPC and the write-off factors for the MFC calculation will be updated based on the Commission's final determination in PECO's 2024 natural gas distribution base rate case at Docket No. R-2024-3046932 (the "2024 Gas Base Rate Case"). The effective date of rates for the 2024 Gas Base Rate Case is anticipated to be on January 1, 2025.

Summing the components of the projected cost of natural gas of $4.2819 per Mcf and the GPC of $0.0386 per Mcf, results in a CC, exclusive of the MFC, of $4.3205 per Mcf.

Lines 2.a. - d. summarize the items used to develop the GCA factor. This sheet shows a net amount of approximately $7.6 million in under-collections, Rate IS profits, supplier refunds and interest to be returned to customers through the GCA factor during the PGC No. 41 application period.

21. Q. Please explain the basis for the approximately $7.6 million net under-collection to be recovered from customers through the GCA factor.

A. Four items determine the net amount. They are set forth below:

<u>Item 1: Over/(Under) Collections (Exhibit APD-3, Pages 2-4)</u>

The recoverable cost of natural gas is subtracted from the CC revenues received, including the adjustment for the prior period reconciliation and excluding GPC and MFC revenues. As of November 30, 2024, the estimated total under-collection balance after reconciliation is expected to be $9,092,745. That figure is brought forward from page 2 to page 1.

<u>Item 2: Rate IS Profit (Exhibit APD-3, Page 5)</u>

The difference between revenues received and costs comprises "profit" from Rate IS customers. As a result of the compliance filing of the 2020 Gas Base Rate Case at Docket No. R-2020-3018929 and later implemented on the effective date of December 1, 2021, for PGC No. 38 at Docket No. R-2021-3025629, future profits are incorporated in distribution base rates. The remaining balance of profits through November 30, 2024, of $1,219, will be returned to customers and is determined by reconciling prior refunds/recoveries of profits through November 30, 2024.

Item 3: Net Interest on Item 1 (Exhibit APD-3, Page 6)

The current period over/under-collection for the SSC is determined monthly. The current interest is calculated by applying an annual interest rate to these over/under collections which is then multiplied by a factor based on an equivalent payback to the midpoint of the PGC No. 41 application period.

Effective December 1, 2016, as a result of PA Act 47 as reflected in the Company's PGC No. 33 Compliance Filing at Docket No. R-2016-2545925, the interest rate used to determine monthly interest for current period under-collections and over-collections is the prime rate for commercial borrowing in effect sixty days prior to the tariff filing in accordance with Section 1307(f).

In accordance with Paragraph 24 of the 2023 Joint Petition for Complete Settlement in the PGC No. 40 proceeding, the Company used the prime rate effective sixty days prior to the date of this filing, which was 8.50%, or the period December 2023 through November 2024. Based on this interest rate, the current interest for the period December 2023 through November 2024 to be recovered from customers for the GCA during the PGC No. 41 application period amounts to $370,572.

Combining the under-collection balance of $491,118 as of November 30, 2023, the current interest to be recovered from customers for the December 2023 through November 2024 time period of $370,572 and the estimated recovery from customers of $116,300 from December 1, 2023 through November 30, 2024 (Exhibit APD-3, page 6), the total interest balance at November 30, 2024, for the GCA to be recovered from customers during the PGC No. 41 application period has an estimated value of $745,390..

<u>Item 4: Supplier Refunds (Including Interest) (Exhibit APD-3, Page 8)</u>

This item is comprised of the actual refunds returned to the Company by suppliers after July 1, 2001, plus interest calculated at 6% through the midpoint of the PGC No. 40 application period less the amount expected to be recovered from customers through November 30, 2024. The net result is an estimated amount of $2,250,387 to be returned to customers as of November 30, 2024.

VI. BALANCING SERVICE COST COMPONENTS

22. Q. Please describe the information shown on page 1 of Exhibit APD-4, which develops the BSC for PGC No. 41 to be effective December 1, 2024.

A. Exhibit APD-4, page 1, summarizes the projected cost that PECO will incur under natural gas storage and peaking agreements with various interstate pipeline and natural gas marketing companies and details the experienced net over/under-collection balance. Page 1, line 1, shows the projected costs for contract storage and peaking services. Lines 2 a. - d. summarize the items used to develop the "E" factor. This sheet shows that the projected recoverable cost for contract storage and peaking services is $26.4 million for the period December 1, 2024 through November 30, 2025. There is also a projected over-collection balance of $4.3 million as of November 30, 2024. This amount includes over-collections, refunds, interest, and miscellaneous surcharge monies to be returned to customers during the PGC No. 41 application period. Page 1, line 3 shows the $22.1 million net amount to be recovered from customers.

23. Q. Please explain the basis for the $22.1 million net amount to be recovered from customers.

A. Five items determine the net amount. They are set forth below:

Item 1: Projected Cost of Gas (Exhibit APD-4, Page 1)

The projected recoverable cost for contract storage facilities and peaking services is $26,408,521 as shown on Exhibit APD-4, page 1.

Item 2: Over/(Under) Collections (Exhibit APD-4, Pages 2-4)

The recoverable cost of natural gas is subtracted from the BSC revenues received, including the adjustment for the prior period reconciliation. The resulting balance is an estimated over-collection of $2,640,891 as of November 30, 2024, which figure is brought forward from page 2 to page 1.

Item 3: Miscellaneous Surcharge Monies (Exhibit APD-4, Page 5)

Transportation balancing surcharges and penalties applied to transportation, Rate TCS and Rate IS customers are returned to firm service customers through the BSC. After reconciling refunds of prior balances and adding current surcharge monies, a projected balance of $1,034,448 as of November 30, 2024, is expected to be returned to customers.

Item 4: Net Interest on Item 2 (Exhibit APD-4, Page 6)

The current period over/under-collections for the BSC are determined monthly. Current interest for the over/under-collections for the BSC is calculated in the same manner as current period interest on over/under-collections for the SSC as described above.

As a result, the current interest for the period December 2023 through November 2024 to be returned to customers for the BSC during the PGC No. 41 application period amounts to $537,596. The current interest is based on the 8.50% interest rate previously described above for the SSC.

Combining the current interest to be returned to customers of $537,596 for the period December 2023 through November 2024 with the over-collected balance of prior period interest of $716,791 as of December 1, 2023, and including the amount returned to customers of $660,951 during the December 1, 2023 through November 30, 2024 period results in an estimated interest balance for the BSC of $593,436 to be returned to customers during the PGC No. 41 application period.

<u>Item 5: Supplier Refunds (Including Interest) (Exhibit APD-4, Page 7)</u>

This item is comprised of the actual refunds returned to the Company by suppliers on or before July 1, 2001, plus interest calculated at 6% through the midpoint of the PGC No. 40 application period, less the amount expected to be returned to customers through November 30, 2024. The net result is an estimated amount of $2,041 as of November 30, 2024, to be returned to customers.

VII. OTHER RATES

24. Q. Does the Company propose to update the monthly demand charge for Rate TS standby sales service?

Yes. The updated monthly demand charge for Rate TS standby sales service will be $20.31 per Mcf.

VIII. CONCLUSION

25. Q. Does this conclude your Direct Testimony?

A. Yes, it does.

Exhibit APD-1

Exhibit APD-1

Changes in Preliminary PGC Rate Prices Effective December 1, 2024

Rates GR, CAP, GC, L, OL and MV-F
(Values in $ per Mcf)

			03/01/24 Unbundled Rates	Change in Rates	12/01/24 Unbundled Rates
Rates GR and CAP		CC	$4.4203	($0.0817)	$4.3386
		GCA	($0.0468)	$0.1961	$0.1493
		BSC	$0.3843	($0.0595)	$0.3248
		Total	$4.7578	$0.0549	$4.8127
Rates GC		CC	$4.4075	($0.0814)	$4.3261
		GCA	($0.0468)	$0.1961	$0.1493
		BSC	$0.3843	($0.0595)	$0.3248
		Total	$4.7450	$0.0552	$4.8002
Rates OL, L and MV-F		CC	$4.4036	($0.0814)	$4.3222
		GCA	($0.0468)	$0.1961	$0.1493
		BSC	$0.3843	($0.0595)	$0.3248
		Total	$4.7411	$0.0552	$4.7963
Rate OL					
	(1.5 MCF)	**CC**	$6.6054	($0.1221)	$6.4833
	(1.7 MCF)		$7.4861	($0.1384)	$7.3477
	(2.1 MCF)		$9.2476	($0.1710)	$9.0766
	(2.4 MCF)		$10.5686	($0.1953)	$10.3733
	(1.5 MCF)	**GCA**	($0.0702)	$0.2942	$0.2240
	(1.7 MCF)		($0.0796)	$0.3334	$0.2538
	(2.1 MCF)		($0.0983)	$0.4118	$0.3135
	(2.4 MCF)		($0.1123)	$0.4706	$0.3583
	(1.5 MCF)	**BSC**	$0.5765	($0.0893)	$0.4872
	(1.7 MCF)		$0.6533	($0.1011)	$0.5522
	(2.1 MCF)		$0.8070	($0.1249)	$0.6821
	(2.4 MCF)		$0.9223	($0.1428)	$0.7795
Rate L					
First 50% of Usage		**CC**	$4.4036	($0.0814)	$4.3222
Additional Use			$4.4036	($0.0814)	$4.3222
First 50% of Usage		**GCA**	($0.0468)	$0.1961	$0.1493
Additional Use			($0.0468)	$0.1961	$0.1493
First 50% of Usage		**BSC**	$0.3843	($0.0595)	$0.3248
Additional Use			$0.3843	($0.0595)	$0.3248
Standby Sales Demand Charge Under Rate TS-F			$19.15	$1.1600	$20.31
Unit Credit for Rate TS-F Standby Sales Purchases			$0.63	$0.0400	$0.67
Balancing Charge-Transportation			$0.0247	($0.0022)	$0.0225

Exhibit APD-2

Exhibit APD-2

PGC No. 41 Calculation Including Gas Procurement Charge (GPC) and Merchant Function Charge (MFC)
Application Period : December 1, 2024 through November 30, 2025
Computation Period : December 1, 2024 through November 30, 2025
$/Mcf

		Rates GR and CAP	Rate GC	Rates OL, L and MV F
CC Including GPC	Exhibit APD-3, Page 1	$4.3205	$4.3205	$4.3205
x				
Write-Off Factor (a)		0.42%	0.13%	0.04%
=				
MFC		$0.0181	$0.0056	$0.0017
CC Including GPC and MFC		$4.3386	$4.3261	$4.3222
GCA	Exhibit APD-3, Page 1	$0.1493	$0.1493	$0.1493
BSC	Exhibit APD-4, Page 1	$0.3248	$0.3248	$0.3248
Total PGC		$4.8127	$4.8002	$4.7963

(a) From Docket No. R-2022-3031113, the 2022 PECO Gas Distribution Base Rate Case

Exhibit APD-3

Computation of Sales Service Cost Adjustment No. 41
Application and Computation Period : 12 Months
December 1, 2024 Through November 30, 2025

1. Projected Commodity Charge Excluding Gas Procurement Charge (GPC)	$291,890,012	Pg. 2	$4.2819	/Mcf
GPC From Docket No. R-2022-3031113			$0.0386	/Mcf
Total CC = Commodity Charge Including GPC			**$4.3205**	/Mcf
2. E = Experienced and Estimated Net Over/(Under)				
a. Commodity Cost Over / (Under)	($9,092,745)	Pg. 2	($0.1789)	/Mcf
b. Rate IS Profit Monies	$1,219	Pg. 5	$0.0000	/Mcf
c. Net Interest on Item a.	($745,390)	Pg. 6	($0.0147)	/Mcf
d. Supplier Refunds (Including Interest)	$2,250,387	Pg. 8	$0.0443	/Mcf
Experienced Net Over/Under Collections - GCA	($7,586,529)		($0.1493)	/Mcf
3. S = Projected Sales for Computation Period CC	68,167,987	mcf		
4. S = Projected Sales for Computation Period GCA	50,811,719	mcf		
GCA Charge / (Credit) to Customers	**$0.1493**	/Mcf		

Month	Gross Cost of Gas Excl. TOP	Total Exclusions	Net Cost of Gas	Allocation Factor	Recoverable Cost of Gas	CC/GCA Revenues In Base	Monthly Over/(Under) Collection	Cumulative Total
	(1)	(2)	(3) = (1) - (2)	(4)	(5) = (3) x (4)	(6)	(7) = (6) - (5)	(8)
Balance - Nov. 30, 2022								($28,308,925)
Dec	$83,176,348	$65,533	$83,110,815	0.99922085	$83,046,059	$50,456,405	($32,589,654)	($60,898,579)
Jan '23	$46,958,810	$104,852	$46,853,958	0.99967838	$46,838,889	$59,559,311	$12,720,422	($48,178,157)
Feb	$37,940,427	$91,402	$37,849,025	0.99935738	$37,824,703	$55,697,736	$17,873,033	($30,305,124)
March	$36,820,397	$22,605	$36,797,792	0.99940670	$36,775,960	$36,285,824	($490,136)	($30,795,260)
April	$7,722,178	$25,666	$7,696,512	0.99965323	$7,693,843	$23,991,509	$16,297,666	($14,497,594)
May	$6,633,770	$13,310	$6,620,460	0.99956264	$6,617,564	$12,875,496	$6,257,932	($8,239,662)
June	$5,222,697	$41,394	$5,181,303	0.99987138	$5,180,637	$7,113,342	$1,932,705	($6,306,957)
July	$5,044,792	$55,792	$4,989,000	0.99983468	$4,988,175	$5,102,325	$114,150	($6,192,807)
Aug	$4,611,997	$2,667	$4,609,330	0.99994228	$4,609,064	$4,532,883	($76,181)	($6,268,988)
Sept	$4,688,398	($2,677)	$4,691,075	0.99973012	$4,689,809	$4,687,633	($2,176)	($6,271,164)
Oct	$6,828,153	$1,822	$6,826,331	0.99948890	$6,822,842	$6,693,191	($129,651)	($6,400,815)
Nov	$22,341,830	$8,586	$22,333,244	0.99925507	$22,316,607	$14,754,720	($7,561,887)	($13,962,702)
12 Months	$267,989,797	$430,952	$267,558,845		$267,404,152	$281,750,375	$14,346,223	
+ PAPUC Bureau of Audits Adjustment (Off System Sales Credit)								$141,990
12 Months -Nov 30, 2024	$223,198,974	$305,313	$222,893,661		$222,801,722		Balance at Nov 30, 2023	($13,820,712)

Exhibit APD-3 Page 2

Month	Gross Cost of Gas Excl. TOP	Total Exclusions	Net Cost of Gas	Allocation Factor	Recoverable Cost of Gas	CC/GCA Revenues In Base	Monthly Over/(Under) Collection	Cumulative Total
	(1)	(2)	(3) = (1) - (2)	(4)	(5) = (3) x (4)	(6)	(7) = (6) - (5)	(8)
Balance - Nov. 30, 2023								($13,820,712)
Dec	$27,676,820	$76,582	$27,600,238	0.99958747	$27,588,852	$29,411,516	$1,822,664	($11,998,048)
Jan '24	$46,944,004	$51,701	$46,892,303	0.99918483	$46,854,078	$33,209,325	($13,644,753)	($25,642,801)
Feb	$29,338,682	$44,380	$29,294,302	1.00000000	$29,294,302	$29,334,453	$40,151	($25,602,650)
March	$21,574,284	$216	$21,574,068	0.99926522	$21,558,216	$28,715,078	$7,156,862	($18,445,788)
April	$10,044,184	$86	$10,044,098	0.99909284	$10,034,986	$19,200,728	$9,165,742	($9,280,046)
May (est)	$11,389,000	$33,779	$11,355,221	0.99966308	$11,351,395	$12,474,891	$1,123,496	($8,156,550)
June (est)	$9,974,000	$24,685	$9,949,315	0.99991268	$9,948,446	$8,234,546	($1,713,900)	($9,870,450)
July (est)	$10,194,000	$16,195	$10,177,805	0.99990212	$10,176,809	$7,358,705	($2,818,104)	($12,688,554)
Aug (est)	$10,089,000	$16,110	$10,072,890	0.99996890	$10,072,577	$7,197,481	($2,875,096)	($15,563,650)
Sept (est)	$9,805,000	$13,790	$9,791,210	0.99985929	$9,789,832	$7,691,209	($2,098,623)	($17,662,273)
Oct (est)	$12,431,000	$9,293	$12,421,707	0.99980022	$12,419,225	$14,739,227	$2,320,002	($15,342,271)
Nov (est)	$23,739,000	$18,496	$23,720,504	0.99968382	$23,713,004	$29,962,530	$6,249,526	($9,092,745)
12 Months	$223,198,974	$305,313	$222,893,661		$222,801,722	$227,529,689	$4,727,967	
12 Months -Nov 30, 2025	$292,536,600	$557,988	$291,978,612		$291,890,012			

	Exclusions						
Month	cost of cgs gas (a) (1)	Cost of Reg IS Cust. Gas (a) (2)	Cost of Indtdpt. IS Gas (a) (3)	Cost of TCS Gas (b) (4)	Cost of MV-I Gas (a) (5)	Rate NGS Exclusion (c) (6)	Total Exclusions (7)
Dec	$0	$51,177	$0	$13,724	$632	$0	$65,533
Jan '23	$0	$30,157	$0	$74,314	$381	$0	$104,852
Feb	$0	$3,445	$0	$87,937	$20	$0	$91,402
March	$0	$7,856	$0	$14,468	$281	$0	$22,605
April	$0	$1,880	$0	$23,674	$112	$0	$25,666
May	$0	$143	$0	$13,066	$101	$0	$13,310
June	$0	$38	$0	$41,333	$23	$0	$41,394
July	$0	$10	$0	$55,772	$10	$0	$55,792
Aug	$0	$2,658	$0	$0	$9	$0	$2,667
Sept	$0	($2,938)	$0	$250	$11	$0	($2,677)
Oct	$0	$24,624	$0	($22,965)	$163	$0	$1,822
Nov	$0	$3,463	$0	$5,016	$107	$0	$8,586
12 Months	$0	$122,513	$0	$306,589	$1,850	$0	$430,952
12 Months -Nov 30, 2024	$0	$0	$0	$0	$0	$0	$0

	Allocation Factor Calculation				
Month	Interdept. Firm Mcf (1)	CC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)	GCA Sales Mcf (5)
Dec	5,098	6,537,888	6,542,986	0.99922085	6,537,888
Jan '23	2,646	8,224,493	8,227,139	0.99967838	8,224,493
Feb	4,947	7,693,270	7,698,217	0.99935738	7,693,270
March	3,261	5,493,108	5,496,369	0.99940670	5,493,108
April	1,365	3,934,905	3,936,270	0.99965323	3,934,905
May	924	2,111,741	2,112,665	0.99956264	2,111,741
June	158	1,228,302	1,228,460	0.99987138	1,228,302
July	158	955,581	955,739	0.99983468	955,581
Aug	49	848,934	848,983	0.99994228	848,934
Sept	237	877,916	878,153	0.99973012	877,916
Oct	641	1,253,524	1,254,165	0.99948890	1,253,524
Nov	2,060	2,763,315	2,765,375	0.99925507	2,763,315
12 Months	21,544	41,922,977	41,944,521		41,922,977

(a) CGS, IS, Eddystone IS and MV-I Sales Volumes x Commodity Price Excl. TOP , CGS incl. Off-Peak Reservation Charge
(b) TCS Sales Volume x (Commodity Price Excl TOP + TCS Fixed Commodity Cost Component)
(c) Demand portion based on Rate CGS Firm Reservation Supply Charge / 30.41 x NGS Sales Volume,
Commodity portion based on Weighted Average Commodity Cost of Gas x NGS Sales Volume

Exclusions and Allocation Factor

Exhibit APD-3 Page 3

	Exclusions						
Month	cost of cgs gas (a) (1)	Cost of Reg IS Cust. Gas (a) (2)	Cost of Indtdpt. IS Gas (a) (3)	Cost of TCS Gas (b) (4)	Cost of MV-I Gas (a) (5)	Rate NGS Exclusion (c) (6)	Total Exclusions (7)
Dec	$0	$32,285	$0	$44,107	$190	$0	$76,582
Jan '24	$0	$13,622	$0	$37,669	$410	$0	$51,701
Feb	$0	$22,174	$0	$22,092	$114	$0	$44,380
March	$0	$0	$0	$0	$216	$0	$216
April	$0	$0	$0	$0	$86	$0	$86
May (est)	$0	$2,124	$0	$31,607	$48	$0	$33,779
June (est)	$0	$2,315	$0	$22,315	$55	$0	$24,685
July (est)	$0	$2,658	$0	$13,478	$59	$0	$16,195
Aug (est)	$0	$2,644	$0	$13,403	$63	$0	$16,110
Sept (est)	$0	$2,356	$0	$11,376	$58	$0	$13,790
Oct (est)	$0	$2,233	$0	$7,006	$54	$0	$9,293
Nov (est)	$0	$3,192	$0	$15,221	$83	$0	$18,496
12 Months	$0	$85,603	$0	$218,274	$1,436	$0	$305,313
12 Months -Nov 30, 2025	$0	$41,662	$0	$515,330	$996	$0	$557,988

	Allocation Factor Calculation				
Month	Interdept. Firm Mcf (1)	CC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)	GCA Sales Mcf (5)
Dec	2,517	6,098,923	6,101,440	0.99958747	6,098,923
Jan '24	6,562	8,043,336	8,049,898	0.99918483	8,043,336
Feb	0	7,107,764	7,107,764	1.00000000	7,107,764
March	4,858	6,606,635	6,611,493	0.99926522	6,606,635
April	3,746	4,125,640	4,129,386	0.99909284	4,125,640
May (est)	924	2,741,532	2,742,456	0.99966308	1,764,236
June (est)	158	1,809,285	1,809,443	0.99991268	1,170,136
July (est)	158	1,614,054	1,614,212	0.99990212	1,087,572
Aug (est)	49	1,575,319	1,575,368	0.99996890	1,114,335
Sept (est)	237	1,684,137	1,684,374	0.99985929	1,179,448
Oct (est)	641	3,207,864	3,208,505	0.99980022	2,553,900
Nov (est)	2,060	6,513,293	6,515,353	0.99968382	5,308,563
12 Months	21,910	51,127,781	51,149,691		46,160,487

(a) CGS, IS, Eddystone IS and MV-I Sales Volumes x Commodity Price Excl. TOP , CGS incl. Off-Peak Reservation Charge
(b) TCS Sales Volume x (Commodity Price Excl TOP + TCS Fixed Commodity Cost Component)
(c) Demand portion based on Rate CGS Firm Reservation Supply Charge / 30.41 x NGS Sales Volume,
Commodity portion based on Weighted Average Commodity Cost of Gas x NGS Sales Volume

	CC Appl. Sales In Month (1)	CC Gas Rates (Excl GRT) (2)	CC Revenues (3) = (1) x (2)	GCA Appl. Sales In Month (4)	Prior Pd. O/(U) Adjust. Rate (5)	Prior Pd. O/(U) Adjust. Revenue (6) = (4) x (5)	Total Revenues Recovered In Base Rates (7) = (3) + (6)
Dec bef 12/1	3,346,941	$7.6921	$25,745,005	3,346,941	$0.4791	$1,603,519	$27,348,524
Dec aft 12/1	3,190,947	$7.0529	$22,505,430	3,190,947	$0.1888	$602,451	$23,107,881
Jan '23 bef 12/1	-	$7.6921	$0		$0.4791	$0	$0
Jan '23 aft 12/1	8,224,493	$7.0529	$58,006,527	8,224,493	$0.1888	$1,552,784	$59,559,311
Feb	7,693,270	$7.0502	$54,239,092	7,693,270	$0.1896	$1,458,644	$55,697,736
March	5,493,108	$6.1688	$33,885,885	5,493,108	$0.4369	$2,399,939	$36,285,824
April	3,934,905	$5.4618	$21,491,664	3,934,905	$0.6353	$2,499,845	$23,991,509
May	2,111,741	$5.4618	$11,533,907	2,111,741	$0.6353	$1,341,589	$12,875,496
June	1,228,302	$5.1612	$6,339,512	1,228,302	$0.6300	$773,830	$7,113,342
July	955,581	$4.7174	$4,507,858	955,581	$0.6221	$594,467	$5,102,325
Aug	848,934	$4.7174	$4,004,761	848,934	$0.6221	$528,122	$4,532,883
Sept	877,916	$4.7174	$4,141,481	877,916	$0.6221	$546,152	$4,687,633
Oct	1,253,524	$4.7174	$5,913,374	1,253,524	$0.6221	$779,817	$6,693,191
Nov	2,763,315	$4.7174	$13,035,662	2,763,315	$0.6221	$1,719,058	$14,754,720
12 Months	41,922,977		$265,350,158	41,922,977		$16,400,217	$281,750,375

SSC Revenues Exhibit APD-3 Page 4

	CC Appl. Sales In Month (1)	CC Gas Rates (Excl GRT) (2)	CC Revenues (3) = (1) x (2)	GCA Appl. Sales In Month (4)	Prior Pd. O/(U) Adjust. Rate (5)	Prior Pd. O/(U) Adjust. Revenue (6) = (4) x (5)	Total Revenues Recovered In Base Rates (7) = (3) + (6)
Dec bef 12/1	3,497,732	$4.7174	$16,500,201	3,497,732	$0.6221	$2,175,939	$18,676,140
Dec aft 12/1	2,601,191	$4.2347	$11,015,264	2,601,191	($0.1076)	($279,888)	$10,735,376
Jan '24 bef 12/1	-	$4.7174	$0		$0.6221	$0	$0
Jan '24 aft 12/1	8,043,336	$4.2354	$34,066,745	8,043,336	($0.1066)	($857,420)	$33,209,325
Feb	7,107,764	$4.2347	$30,099,248	7,107,764	($0.1076)	($764,795)	$29,334,453
March	6,606,635	$4.2882	$28,330,572	6,606,635	$0.0582	$384,506	$28,715,078
April	4,125,640	$4.3632	$18,000,992	4,125,640	$0.2908	$1,199,736	$19,200,728
May (est)	2,741,532	$4.3632	$11,961,851	1,764,236	$0.2908	$513,040	$12,474,891
June (est)	1,809,285	$4.3632	$7,894,271	1,170,136	$0.2908	$340,275	$8,234,546
July (est)	1,614,054	$4.3632	$7,042,439	1,087,572	$0.2908	$316,266	$7,358,705
Aug (est)	1,575,319	$4.3632	$6,873,432	1,114,335	$0.2908	$324,049	$7,197,481
Sept (est)	1,684,137	$4.3632	$7,348,226	1,179,448	$0.2908	$342,983	$7,691,209
Oct (est)	3,207,864	$4.3632	$13,996,553	2,553,900	$0.2908	$742,674	$14,739,227
Nov (est)	6,513,293	$4.3632	$28,418,800	5,308,563	$0.2908	$1,543,730	$29,962,530
12 Months	51,127,781		$221,548,594	46,160,487		$5,981,095	$227,529,689

IS Profits

	Gross	IS Gas	Unauth.	"Net"	Reg IS		Total	Increase	Profit to Be	Applicable	IS Profit	IS Profits	Cumulative
	Gross Reg IS Revenue	IS Gas Penalty Revenue	Unauth. IS Gas Revenue	"Net" IS Reg Revenue	Reg IS Sales Mcf	Commodity Cost/Mcf	Total Reg IS Cost of Gas	Increase In Taxable Income	Profit to Be Returned To Customers	Applicable GCA Sales	IS Profit Return Rate	IS Profits Distributed to Custs.	Cumulative Over/(Under) Reconciliation
	(1)	(2)	(3)	(4) = (1)-(2)-(3)	(5)	(6)	(7) = (5) x (6)	(8) = (4) - (7)	(9) = (8) x 0% (a)	(10)	(11)	(12) = (10) x (11)	(13) = (9) - (12)
Balance - Nov. 30, 2022													($5,330)
Dec bef 12/1										3,346,941	($0.0007)	($2,343)	($2,987)
Dec aft 12/1	$52,498	$0	$0	$52,498	6,401	$7.9952	$51,177	$1,321	$0	3,190,947	($0.0001)	($319)	($2,668)
Jan '23 bef 12/1										0	($0.0007)	$0	($2,668)
Jan '23 aft 12/1	$42,443	$0	$0	$42,443	4,434	$6.8013	$30,157	$12,286	$0	8,224,493	($0.0001)	($822)	($1,846)
Feb	$5,244	$0	$0	$5,244	506	$6.8078	$3,445	$1,799	$0	7,693,270	($0.0001)	($769)	($1,077)
March	$14,562	$0	$0	$14,562	1,593	$4.9317	$7,856	$6,706	$0	5,493,108	($0.0001)	($549)	($528)
April	$5,595	$0	$0	$5,595	655	$2.8698	$1,880	$3,715	$0	3,934,905	($0.0001)	($393)	($135)
May	$628	$0	$0	$628	64	$2.2334	$143	$485	$0	2,111,741	($0.0001)	($211)	$76
June	$363	$0	$0	$363	23	$1.6560	$38	$325	$0	1,228,302	($0.0001)	($123)	$199
July	$272	$0	$0	$272	8	$1.2926	$10	$262	$0	955,581	($0.0001)	($96)	$295
Aug	$13,619	$0	$0	$13,619	2,042	$1.3015	$2,658	$10,961	$0	848,934	($0.0001)	($85)	$380
Sept	($9,887)	$0	$0	($9,887)	(1,567)	$1.8752	($2,938)	($6,949)	$0	877,916	($0.0001)	($88)	$468
Oct	$53,459	$0	$0	$53,459	7,567	$3.2541	$24,624	$28,835	$0	1,253,524	($0.0001)	($125)	$593
Nov	$7,126	$0	$0	$7,126	941	$3.6797	$3,463	$3,663	$0	2,763,315	($0.0001)	($276)	$869
12 Months	$185,922	$0	$0	$185,922	22,667		$122,513	$63,409	$0	41,922,977		($6,199)	$6,199
Balance at Nov 30, 2023													$869

(a) From Docket No. R-2020-3018929 and Docket No. R-2021-3025629

IS Profits

	Gross Reg IS Revenue	IS Gas Penalty Revenue	Unauth. IS Gas Revenue	"Net" IS Reg Revenue	Reg IS Sales Mcf	Commodity Cost/Mcf	Total Reg IS Cost of Gas	Increase In Taxable Income	Profit to Be Returned To Customers	Applicable GCA Sales	IS Profit Return Rate	IS Profits Distributed to Custs.	Cumulative Over/(Under) Reconciliation
	(1)	(2)	(3)	(4) = (1)-(2)-(3)	(5)	(6)	(7) = (5) x (6)	(8) = (4) - (7)	(9) = (8) x 0% (a)	(10)	(11)	(12) = (10) x (11)	(13) = (9) - (12)
Balance - Nov. 30, 2023													$869
Dec bef 12/1										3,497,732	($0.0001)	($350)	$1,219
Dec aft 12/1	$85,443	$0	$0	$85,443	10,012	$3.2246	$32,285	$53,158	$0	2,601,191	$0.0000	$0	$1,219
Jan '24 bef 12/1										0	($0.0001)	$0	$1,219
Jan '24 aft 12/1	$7,095	$0	$0	$7,095	931	$14.6321	$13,622	($6,527)	$0	8,043,336	$0.0000	$0	$1,219
Feb	$35,935	$0	$0	$35,935	5,054	$4.3875	$22,174	$13,761	$0	7,107,764	$0.0000	$0	$1,219
March	$0	$0	$0	$0	0	$3.4775	$0	$0	$0	6,606,635	$0.0000	$0	$1,219
April	$0	$0	$0	$0	0	$2.1930	$0	$0	$0	4,125,640	$0.0000	$0	$1,219
May (est)	$5,956	$0	$0	$5,956	1,370	$1.5500	$2,124	$3,832	$0	1,764,236	$0.0000	$0	$1,219
June (est)	$6,148	$0	$0	$6,148	1,370	$1.6900	$2,315	$3,833	$0	1,170,136	$0.0000	$0	$1,219
July (est)	$6,490	$0	$0	$6,490	1,370	$1.9400	$2,658	$3,832	$0	1,087,572	$0.0000	$0	$1,219
Aug (est)	$6,477	$0	$0	$6,477	1,370	$1.9300	$2,644	$3,833	$0	1,114,335	$0.0000	$0	$1,219
Sept (est)	$6,189	$0	$0	$6,189	1,370	$1.7200	$2,356	$3,833	$0	1,179,448	$0.0000	$0	$1,219
Oct (est)	$6,066	$0	$0	$6,066	1,370	$1.6300	$2,233	$3,833	$0	2,553,900	$0.0000	$0	$1,219
Nov (est)	$7,025	$0	$0	$7,025	1,370	$2.3300	$3,192	$3,833	$0	5,308,563	$0.0000	$0	$1,219
12 Months	$172,822	$0	$0	$172,822	25,587		$85,603	$87,219	$0	46,160,487		($350)	$350
Balance at Nov 30, 2024													$1,219

(a) From Docket No. R-2020-3018929 and Docket No. R-2021-3025629

Interest on Moneys Owed to Customers - Summary

	CC Portion of SSC	Recoverable	Current Over/(Under)	Interest	Interest	Total Interest	Interest Given Back To (or Collected From) Customers			
	of SSC Revenue	Recoverable Cost of Gas	Over/(Under) Collection for Interest	Interest Rate	Interest Time Factor	Interest to be Ret. to Custs.	Interest Given Back To (or Collected From) Customers			
							GCA Applicable Sales	Interest Refund rate	Interest Refund	Cumulative Total
Month	(1)	(2)	(3) = (1) - (2)	(4)	(5)	(6) = (3) x (4) x (5)	(7)	(8)	(9) = (7) x (8)	(10) = (6) - (9)
Balance - Nov. 30, 2022										($745,087)
Dec bef 12/1							3,346,941	($0.0071)	($23,763)	($721,324)
Dec aft 12/1	$48,250,435	$83,046,059	($34,795,624)	8.00%	18/12	($4,175,475)	3,190,947	($0.0075)	($23,932)	($4,872,867)
Jan '23 bef 12/1							-	($0.0071)	$0	($4,872,867)
Jan '23 aft 12/1	$58,006,527	$46,838,889	$11,167,638	8.00%	17/12	$1,265,666	8,224,493	($0.0075)	($61,684)	($3,545,517)
Feb	$54,239,092	$37,824,703	$16,414,389	8.00%	16/12	$1,750,868	7,693,270	($0.0075)	($57,700)	($1,736,949)
March	$33,885,885	$36,775,960	($2,890,075)	8.00%	15/12	($289,008)	5,493,108	($0.0126)	($69,213)	($1,956,744)
April	$21,491,664	$7,693,843	$13,797,821	8.00%	14/12	$1,287,797	3,934,905	($0.0167)	($65,713)	($603,234)
May	$11,533,907	$6,617,564	$4,916,343	8.00%	13/12	$426,083	2,111,741	($0.0167)	($35,266)	($141,885)
June	$6,339,512	$5,180,637	$1,158,875	8.00%	12/12	$92,710	1,228,302	($0.0166)	($20,390)	($28,785)
July	$4,507,858	$4,988,175	($480,317)	8.00%	11/12	($35,223)	955,581	($0.0164)	($15,672)	($48,336)
Aug	$4,004,761	$4,609,064	($604,303)	8.00%	10/12	($40,287)	848,934	($0.0164)	($13,923)	($74,700)
Sept	$4,141,481	$4,689,809	($548,328)	8.00%	9/12	($32,900)	877,916	($0.0164)	($14,398)	($93,202)
Oct	$5,913,374	$6,822,842	($909,468)	8.00%	8/12	($48,505)	1,253,524	($0.0164)	($20,558)	($121,149)
Nov	$13,035,662	$22,316,607	($9,280,945)	8.00%	7/12	($433,111)	2,763,315	($0.0164)	($45,318)	($508,942)
12 Months	$265,350,158	$267,404,152	($2,053,994)			($231,385)	41,922,977		($467,530)	$236,145
+ PAPUC Bureau of Audits Adjustment (Off System Sales Credit Int Adj = $20,220 and Supplier Refund Int Adj = -$2,396)										$17,824
Balance at Nov 30, 2023										($491,118)

Interest on Moneys Owed to Customers - Summary

Exhibit APD-3 Page 6

	CC Portion of SSC Revenue	Recoverable Cost of Gas	Current Over/(Under) Collection for Interest	Interest Rate	Interest Time Factor	Total Interest to be Ret. to Custs.	Interest Given Back To (or Collected From) Customers			
							GCA Applicable Sales	Interest Refund rate	Interest Refund	Cumulative Total
Month	(1)	(2)	(3) = (1) - (2)	(4)	(5)	(6) = (3) x (4) x (5)	(7)	(8)	(9) = (7) x (8)	(10) = (6) - (9)
Balance - Nov. 30, 2023										($491,118)
Dec bef 12/1							3,497,732	($0.0164)	($57,363)	($433,755)
Dec aft 12/1	$27,515,465	$27,588,852	($73,387)	8.50%	18/12	($9,357)	2,601,191	$0.0073	$18,989	($462,101)
Jan '24 bef 12/1							-	($0.0164)	$0	($462,101)
Jan '24 aft 12/1	$34,066,745	$46,854,078	($12,787,333)	8.50%	17/12	($1,539,808)	8,043,336	$0.0073	$58,716	($2,060,625)
Feb	$30,099,248	$29,294,302	$804,946	8.50%	16/12	$91,227	7,107,764	$0.0073	$51,887	($2,021,285)
March	$28,330,572	$21,558,216	$6,772,356	8.50%	15/12	$719,563	6,606,635	$0.0000	$0	($1,301,722)
April	$18,000,992	$10,034,986	$7,966,006	8.50%	14/12	$789,962	4,125,640	($0.0103)	($42,494)	($469,266)
May (est)	$11,961,851	$11,351,395	$610,456	8.50%	13/12	$56,213	1,764,236	($0.0103)	($18,172)	($394,881)
June (est)	$7,894,271	$9,948,446	($2,054,175)	8.50%	12/12	($174,605)	1,170,136	($0.0103)	($12,052)	($557,434)
July (est)	$7,042,439	$10,176,809	($3,134,370)	8.50%	11/12	($244,220)	1,087,572	($0.0103)	($11,202)	($790,452)
Aug (est)	$6,873,432	$10,072,577	($3,199,145)	8.50%	10/12	($226,606)	1,114,335	($0.0103)	($11,478)	($1,005,580)
Sept (est)	$7,348,226	$9,789,832	($2,441,606)	8.50%	9/12	($155,652)	1,179,448	($0.0103)	($12,148)	($1,149,084)
Oct (est)	$13,996,553	$12,419,225	$1,577,328	8.50%	8/12	$89,382	2,553,900	($0.0103)	($26,305)	($1,033,397)
Nov (est)	$28,418,800	$23,713,004	$4,705,796	8.50%	7/12	$233,329	5,308,563	($0.0103)	($54,678)	($745,390)
12 Months	$221,548,594	$222,801,722	($1,253,128)			($370,572)	46,160,487		($116,300)	($254,272)
Balance at Nov 30, 2024										($745,390)

PUC Adjustment plus Interest — Exhibit APD-3 — Page 7

GCA PUC Adj. PUC Adjust.

Month	GCA Applicable Sales (1)	PUC Adj. Factor $/Mcf (2)	PUC Adjust. Revenues Retrnd To Custs. (3) = (1) x (2)	
Balance - Nov. 30, 2022				($1,311)
Dec bef 12/1	3,346,941	$0.0000	$0	($1,311)
Dec aft 12/1	3,190,947	$0.0000	$0	($1,311)
Jan '23 bef 12/1	-	$0.0000	$0	($1,311)
Jan '23 aft 12/1	8,224,493	$0.0000	$0	($1,311)
Feb	7,693,270	$0.0000	$0	($1,311)
March	5,493,108	$0.0000	$0	($1,311)
April	3,934,905	$0.0000	$0	($1,311)
May	2,111,741	$0.0000	$0	($1,311)
June	1,228,302	$0.0000	$0	($1,311)
July	955,581	$0.0000	$0	($1,311)
Aug	848,934	$0.0000	$0	($1,311)
Sept	877,916	$0.0000	$0	($1,311)
Oct	1,253,524	$0.0000	$0	($1,311)
Nov	2,763,315	$0.0000	$0	($1,311)
12 Months	41,922,977		$0	
Balance at Nov 30, 2023				($1,311)

PUC Adjustment plus Interest — Exhibit APD-3 — Page 7

Month	GCA Applicable Sales (1)	PUC Adj. Factor $/Mcf (2)	PUC Adjust. Revenues Retrnd To Custs. (3) = (1) x (2)	
Balance - Nov. 30, 2023				($1,311)
Dec bef 12/1	3,497,732	$0.0000	$0	($1,311)
Dec aft 12/1	2,601,191	$0.0000	$0	($1,311)
Jan '24 bef 12/1	-	$0.0000	$0	($1,311)
Jan '24 aft 12/1	8,043,336	$0.0000	$0	($1,311)
Feb	7,107,764	$0.0000	$0	($1,311)
March	6,606,635	$0.0000	$0	($1,311)
April	4,125,640	$0.0000	$0	($1,311)
May (est)	1,764,236	$0.0000	$0	($1,311)
June (est)	1,170,136	$0.0000	$0	($1,311)
July (est)	1,087,572	$0.0000	$0	($1,311)
Aug (est)	1,114,335	$0.0000	$0	($1,311)
Sept (est)	1,179,448	$0.0000	$0	($1,311)
Oct (est)	2,553,900	$0.0000	$0	($1,311)
Nov (est)	5,308,563	$0.0000	$0	($1,311)
12 Months	46,160,487		$0	
Balance at Nov 30, 2024				($1,311)

Supplier Refunds Including Interest - Summary Sheet | Exhibit APD-3 | Page 8

	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			
	to be Returned to Customers					Actually Returned to Customers			
	Supplier Refunds (1)	Interest Rate (2)	Time Factor (3)	Interest (4) =(1) x (2) x (3)	Total (5) = (1) + (4)	GCA Applicable Sales (6)	Supplier Refund Rate (7)	Supplier Refund (8) = (6) x (7)	Cumulative Total (9) = (5) - (8)
Balance - Nov. 30, 2022									($295,139)
Dec bef 12/1		6.00%			$0	3,346,941	$0.0566	$189,437	($484,576)
Dec aft 12/1	$0	6.00%	18/12	$0	$0	3,190,947	($0.0097)	($30,952)	($453,624)
Jan '23 bef 12/1		6.00%			$0	-	$0.0566	$0	($453,624)
Jan '23 aft 12/1	$4,029	6.00%	17/12	$342	$4,371	8,224,493	($0.0097)	($79,778)	($369,475)
Feb	$456	6.00%	16/12	$36	$492	7,693,270	($0.0097)	($74,625)	($294,358)
March	$607,635	6.00%	15/12	$45,573	$653,208	5,493,108	($0.0080)	($43,945)	$402,795
April	$15,519,161	6.00%	14/12	$1,086,341	$16,605,502	3,934,905	($0.0066)	($25,970)	$17,034,267
May	$1,254,773	6.00%	13/12	$81,560	$1,336,333	2,111,741	($0.0066)	($13,937)	$18,384,537
June	($1,856,967)	6.00%	12/12	($111,418)	($1,968,385)	1,228,302	($0.0066)	($8,107)	$16,424,259
July	$21,716	6.00%	11/12	$1,194	$22,910	955,581	($0.0065)	($6,211)	$16,453,380
Aug	($633)	6.00%	10/12	($32)	($665)	848,934	($0.0065)	($5,518)	$16,458,233
Sept	$0	6.00%	9/12	$0	$0	877,916	($0.0065)	($5,706)	$16,463,939
Oct	$35,891	6.00%	8/12	$1,436	$37,327	1,253,524	($0.0065)	($8,148)	$16,509,414
Nov	$3,146	6.00%	7/12	$110	$3,256	2,763,315	($0.0065)	($17,962)	$16,530,632
12 Months	$15,589,207			$1,105,142	$16,694,349	41,922,977		($131,422)	$16,825,771
+ PAPUC Bureau of Audits Adjustment (Interest for Supplier Refunds)									$4,184
Balance at Nov 30, 2023									$16,534,816

Supplier Refunds Including Interest - Summary Sheet | Exhibit APD-3 | Page 8

	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			
	Supplier Refunds (1)	Interest Rate (2)	Time Factor (3)	Interest (4) =(1) x (2) x (3)	Total (5) = (1) + (4)	GCA Applicable Sales (6)	Supplier Refund Rate (7)	Supplier Refund (8) = (6) x (7)	Cumulative Total (9) = (5) - (8)
Balance - Nov. 30, 2023									$16,534,816
Dec bef 12/1		6.00%			$0	3,497,732	($0.0065)	($22,735)	$16,557,551
Dec aft 12/1	$8,985	6.00%	18/12	$809	$9,794	2,601,191	$0.3238	$842,266	$15,725,079
Jan '24 bef 12/1		6.00%			$0	-	($0.0065)	$0	$15,725,079
Jan '24 aft 12/1	$378	6.00%	17/12	$32	$410	8,043,336	$0.3233	$2,600,411	$13,125,078
Feb	$0	6.00%	16/12	$0	$0	7,107,764	$0.3238	$2,301,494	$10,823,584
March	$0	6.00%	15/12	$0	$0	6,606,635	$0.3338	$2,205,295	$8,618,289
April	$0	6.00%	14/12	$0	$0	4,125,640	$0.3479	$1,435,310	$7,182,979
May (est)	$0	6.00%	13/12	$0	$0	1,764,236	$0.3479	$613,778	$6,569,201
June (est)	$0	6.00%	12/12	$0	$0	1,170,136	$0.3479	$407,090	$6,162,111
July (est)	$0	6.00%	11/12	$0	$0	1,087,572	$0.3479	$378,366	$5,783,745
Aug (est)	$0	6.00%	10/12	$0	$0	1,114,335	$0.3479	$387,677	$5,396,068
Sept (est)	$0	6.00%	9/12	$0	$0	1,179,448	$0.3479	$410,330	$4,985,738
Oct (est)	$0	6.00%	8/12	$0	$0	2,553,900	$0.3479	$888,502	$4,097,236
Nov (est)	$0	6.00%	7/12	$0	$0	5,308,563	$0.3479	$1,846,849	$2,250,387
12 Months	$9,363			$841	$10,204	46,160,487		$14,294,633	($14,284,429)
Balance at Nov 30, 2024									$2,250,387

Month	Gross Cost of Gas Excl. TOP (1)	Total Exclusions (2)	Net Cost of Gas (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost of Gas (5) = (3) x (4)
Balance - Nov. 30, 2024					
Dec (est)	$38,542,550	$49,181	$38,493,369	0.99975996	$38,484,129
Jan '25 (est)	$49,395,550	$90,037	$49,305,513	0.99949618	$49,280,672
Feb (est)	$43,164,300	$97,544	$43,066,756	1.00000000	$43,066,756
March (est)	$35,577,800	$87,893	$35,489,907	0.99947111	$35,471,137
April (est)	$20,216,300	$58,985	$20,157,315	0.99925326	$20,142,263
May (est)	$14,757,300	$46,606	$14,710,694	0.99966442	$14,705,757
June (est)	$12,297,300	$32,811	$12,264,489	0.99991335	$12,263,426
July (est)	$12,337,300	$20,853	$12,316,447	0.99990309	$12,315,253
Aug (est)	$12,141,300	$20,623	$12,120,677	0.99996921	$12,120,304
Sept (est)	$11,748,300	$17,741	$11,730,559	0.99986070	$11,728,925
Oct (est)	$15,328,300	$12,575	$15,315,725	0.99980228	$15,312,697
Nov (est)	$27,030,300	$23,139	$27,007,161	0.99968647	$26,998,693
12 Months	$292,536,600	$557,988	$291,978,612		$291,890,012

SSC Revenues

	CC Appl. Sales In Month (1)	CC Gas Rates (Excl GRT) (2)	CC Revenues (3) = (1) x (2)
Dec bef 12/1	5,379,003	$4.3632	$23,469,666
Dec aft 12/1	5,104,340	$4.2819	$21,856,274
Jan '25 bef 12/1	-	$4.3632	$0
Jan '25 aft 12/1	13,017,998	$4.2819	$55,741,767
Feb (est)	11,165,429	$4.2819	$47,809,250
March (est)	9,180,357	$4.2819	$39,309,369
April (est)	5,012,713	$4.2819	$21,463,935
May (est)	2,752,522	$4.2819	$11,786,026
June (est)	1,823,243	$4.2819	$7,806,943
July (est)	1,630,199	$4.2819	$6,980,347
Aug (est)	1,591,425	$4.2819	$6,814,321
Sept (est)	1,701,174	$4.2819	$7,284,257
Oct (est)	3,241,308	$4.2819	$13,878,956
Nov (est)	6,568,277	$4.2819	$28,124,704
12 Months	68,167,987		$292,325,815

Interest on Moneys Owed to Customers - Summary

Month	CC Portion of SSC Revenue (1)	Recoverable Cost of Gas (2)	Current Over/(Under) Collection for Interest (3) = (1) - (2)
Balance - Nov. 30, 2024			
Dec bef 12/1			
Dec aft 12/1	$45,325,940	$38,484,129	$6,841,811
Jan '25 bef 12/1			
Jan '25 aft 12/1	$55,741,767	$49,280,672	$6,461,095
Feb (est)	$47,809,250	$43,066,756	$4,742,494
March (est)	$39,309,369	$35,471,137	$3,838,232
April (est)	$21,463,935	$20,142,263	$1,321,672
May (est)	$11,786,026	$14,705,757	($2,919,731)
June (est)	$7,806,943	$12,263,426	($4,456,483)
July (est)	$6,980,347	$12,315,253	($5,334,906)
Aug (est)	$6,814,321	$12,120,304	($5,305,983)
Sept (est)	$7,284,257	$11,728,925	($4,444,668)
Oct (est)	$13,878,956	$15,312,697	($1,433,741)
Nov (est)	$28,124,704	$26,998,693	$1,126,011
12 Months	$292,325,815	$291,890,012	$435,803

Exhibit APD-4

Computation of Balancing Service Cost Adjustment No. 41
Application and Computation Period : 12 Months
December 1, 2024 Through November 30, 2025

1. C = Projected Cost of Gas for Application Period	$26,408,521	Pg. 2	$0.3874	/Mcf
2. E = Experienced and Estimated Net Over/(Under)				
a. Balancing Over / (Under)	$2,640,891	Pg. 2	$0.0387	/Mcf
b. Miscellaneous Surcharge Monies	$1,034,448	Pg. 5	$0.0152	/Mcf
c. Net Interest on Item a.	$593,436	Pg. 6	$0.0087	/Mcf
d. Supplier Refunds (Including Interest)	$2,041	Pg. 7	$0.0000	/Mcf
Experienced Net Over/(Under) Collections	$4,270,816		$0.0626	/Mcf
3. C - E	$22,137,705		$0.3248	/Mcf
4. S = Projected Sales for Computation Period	68,167,987	mcf		
Charge / (Credit) to Customers	$0.3248	/Mcf		

Over/(Under) Collections

Month	Gross Cost of Storage (1)	Total Exclusions (2)	Net Cost of Storage (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost (5) = (3) x (4)	BSC Revenues In Base (6)	Monthly Over/(Under) Collection (7) = (6) - (5)	Cumulative Total (8)
Balance	-Nov 30, 2022							($911,479)
Dec	$2,643,188	$25,127	$2,618,061	0.99942853	$2,616,565	$4,638,358	$2,021,793	$1,110,314
Jan '23	$2,680,550	$33,273	$2,647,277	0.99976352	$2,646,651	$6,471,327	$3,824,676	$4,934,990
Feb	$2,606,166	$33,787	$2,572,379	0.99951594	$2,571,134	$5,908,295	$3,337,161	$8,272,151
March	$2,550,415	$27,013	$2,523,402	0.99958039	$2,522,343	$4,406,183	$1,883,840	$10,155,991
April	$2,244,364	$29,096	$2,215,268	0.99975379	$2,214,723	$3,093,952	$879,229	$11,035,220
May	$2,119,795	$28,353	$2,091,442	0.99970097	$2,090,817	$1,724,300	($366,517)	$10,668,703
June	$2,127,861	$34,775	$2,093,086	0.99991540	$2,092,909	$872,473	($1,220,436)	$9,448,267
July	$2,114,726	$37,640	$2,077,086	0.99989340	$2,076,865	$493,082	($1,583,783)	$7,864,484
Aug	$2,136,965	$25,768	$2,111,197	0.99996259	$2,111,118	$435,810	($1,675,308)	$6,189,176
Sept	$2,124,862	$25,651	$2,099,211	0.99982861	$2,098,851	$459,992	($1,638,859)	$4,550,317
Oct	$2,118,583	$20,164	$2,098,419	0.99966407	$2,097,714	$634,621	($1,463,093)	$3,087,224
Nov	$2,129,251	$24,821	$2,104,430	0.99948112	$2,103,338	$1,320,168	($783,170)	$2,304,054
12 Months	$27,596,726	$345,468	$27,251,258		$27,243,028	$30,458,561	$3,215,533	
12 Months -Nov 30, 2024	$25,906,860	$294,337	$25,612,523		$25,605,531			

Over/(Under) Collections

Month	Gross Cost of Storage (1)	Total Exclusions (2)	Net Cost of Storage (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost (5) = (3) x (4)	BSC Revenues In Base (6)	Monthly Over/(Under) Collection (7) = (6) - (5)	Cumulative Total (8)
Balance	-Nov 30, 2023							$2,304,054
Dec	$2,101,934	$26,721	$2,075,213	0.99970230	$2,074,595	$3,110,210	$1,035,615	$3,339,669
Jan '24	$2,176,115	$24,632	$2,151,483	0.99940813	$2,150,210	$4,601,633	$2,451,423	$5,791,092
Feb	$2,217,872	$20,892	$2,196,980	1.00000000	$2,196,980	$4,076,411	$1,879,431	$7,670,523
March	$2,168,234	$16,983	$2,151,251	0.99947034	$2,150,112	$3,802,513	$1,652,401	$9,322,924
April	$2,179,705	$20,599	$2,159,106	0.99936098	$2,157,726	$2,425,372	$267,646	$9,590,570
May (est)	$2,149,000	$28,044	$2,120,956	0.99966308	$2,120,241	$1,134,994	($985,247)	$8,605,323
June (est)	$2,128,000	$25,680	$2,102,320	0.99991268	$2,102,136	$749,044	($1,353,092)	$7,252,231
July (est)	$2,149,000	$24,940	$2,124,060	0.99990212	$2,123,852	$668,218	($1,455,634)	$5,796,597
Aug (est)	$2,149,000	$24,296	$2,124,704	0.99996890	$2,124,638	$652,182	($1,472,456)	$4,324,141
Sept (est)	$2,128,000	$23,407	$2,104,593	0.99985929	$2,104,297	$697,233	($1,407,064)	$2,917,077
Oct (est)	$2,149,000	$26,519	$2,122,481	0.99980022	$2,122,057	$1,328,055	($794,002)	$2,123,075
Nov (est)	$2,211,000	$31,624	$2,179,376	0.99968382	$2,178,687	$2,696,503	$517,816	$2,640,891
12 Months	$25,906,860	$294,337	$25,612,523		$25,605,531	$25,942,368	$336,837	
12 Months -Nov 30, 2025	$26,791,000	$375,385	$26,415,615		$26,408,521			

	Exclusions					Allocation Factor Calculation			
Month	Standby Sales Service (1)	Cost of TCS Gas (a) (2)	Rate NGS Exclusion (b) (3)	Total Exclusions (4) = (1) + (2) + (3)		Interdept. Firm Mcf (1)	BSC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)
Dec	$24,279	$848	$0	$25,127	Dec	5,098	8,915,764	8,920,862	0.99942853
Jan '23	$26,975	$6,298	$0	$33,273	Jan '23	2,646	11,186,391	11,189,037	0.99976352
Feb	$25,529	$8,258	$0	$33,787	Feb	4,947	10,214,894	10,219,841	0.99951594
March	$25,680	$1,333	$0	$27,013	March	3,261	7,768,307	7,771,568	0.99958039
April	$25,834	$3,262	$0	$29,096	April	1,365	5,542,730	5,544,095	0.99975379
May	$25,846	$2,507	$0	$28,353	May	924	3,089,037	3,089,961	0.99970097
June	$25,569	$9,206	$0	$34,775	June	158	1,867,451	1,867,609	0.99991540
July	$25,259	$12,381	$0	$37,640	July	158	1,482,063	1,482,221	0.99989340
Aug	$25,768	$0	$0	$25,768	Aug	49	1,309,918	1,309,967	0.99996259
Sept	$25,590	$61	$0	$25,651	Sept	237	1,382,605	1,382,842	0.99982861
Oct	$24,798	($4,634)	$0	$20,164	Oct	641	1,907,488	1,908,129	0.99966407
Nov	$24,183	$638	$0	$24,821	Nov	2,060	3,968,045	3,970,105	0.99948112
12 Months	$305,310	$40,158	$0	$345,468	12 Months	21,544	58,634,693	58,656,237	
12 Months -Nov 30, 2024	$0	$0	$0	$0					

(a) TCS Sales Volume x TCS Fixed Cost Storage Component
(b) Based on C factor portion of Balancing Service Charge (BSC) x NGS Sales Volume

Exclusions and Allocation Factor Exhibit APD-4 Page 3

	Exclusions					Allocation Factor Calculation			
Month	Standby Sales Service (1)	Cost of TCS Gas (a) (2)	Rate NGS Exclusion (b) (3)	Total Exclusions (4) = (1) + (2) + (3)		Interdept. Firm Mcf (1)	BSC Sales Mcf (2)	Total Applicable Sales Mcf (3) = (1) + (2)	Allocation Factor (4) = (2)/(3)
Dec	$21,914	$4,807	$0	$26,721	Dec	2,517	8,452,307	8,454,824	0.99970230
Jan '24	$21,062	$3,570	$0	$24,632	Jan '24	6,562	11,080,263	11,086,825	0.99940813
Feb	$18,333	$2,559	$0	$20,892	Feb	0	9,813,218	9,813,218	1.00000000
March	$16,983	$0	$0	$16,983	March	4,858	9,167,098	9,171,956	0.99947034
April	$20,599	$0	$0	$20,599	April	3,746	5,858,386	5,862,132	0.99936098
May (est)	$22,402	$5,642	$0	$28,044	May (est)	924	2,741,532	2,742,456	0.99966308
June (est)	$21,898	$3,782	$0	$25,680	June (est)	158	1,809,285	1,809,443	0.99991268
July (est)	$22,845	$2,095	$0	$24,940	July (est)	158	1,614,054	1,614,212	0.99990212
Aug (est)	$22,206	$2,090	$0	$24,296	Aug (est)	49	1,575,319	1,575,368	0.99996890
Sept (est)	$21,500	$1,907	$0	$23,407	Sept (est)	237	1,684,137	1,684,374	0.99985929
Oct (est)	$25,305	$1,214	$0	$26,519	Oct (est)	641	3,207,864	3,208,505	0.99980022
Nov (est)	$29,529	$2,095	$0	$31,624	Nov (est)	2,060	6,513,293	6,515,353	0.99968382
12 Months	$264,576	$29,761	$0	$294,337	12 Months	21,910	63,516,755	63,538,665	
12 Months -Nov 30, 2025	$325,250	$50,135	$0	$375,385					

(a) TCS Sales Volume x TCS Fixed Cost Storage Component
(b) Based on C factor portion of Balancing Service Charge (BSC) x NGS Sales Volume

BSC Revenues

	BSC Appl. Sales mcf (1)	Cost of Gas Rates (Excl GRT) (2)	Cost of Gas Revenues (3) = (1) x (2)	Prior Pd. O/(U) Adjust. Rate (4)	Prior Pd. O/(U) Adjust. Revenue (5) = (1) x (4)	Total Revenues Recovered In Base Rates (6) = (3) + (5)
Dec bef 12/1	4,564,247	$0.4639	$2,117,354	$0.0008	$3,651	$2,121,005
Dec aft 12/1	4,351,517	$0.5799	$2,523,445	($0.0014)	($6,092)	$2,517,353
Jan '23 bef 12/1	-	$0.4639	$0	$0.0008	$0	$0
Jan '23 aft 12/1	11,186,391	$0.5799	$6,486,988	($0.0014)	($15,661)	$6,471,327
Feb	10,214,894	$0.5798	$5,922,596	($0.0014)	($14,301)	$5,908,295
March	7,768,307	$0.5598	$4,348,698	$0.0074	$57,485	$4,406,183
April	5,542,730	$0.5437	$3,013,582	$0.0145	$80,370	$3,093,952
May	3,089,037	$0.5437	$1,679,509	$0.0145	$44,791	$1,724,300
June	1,867,451	$0.4526	$845,208	$0.0146	$27,265	$872,473
July	1,482,063	$0.3180	$471,296	$0.0147	$21,786	$493,082
Aug	1,309,918	$0.3180	$416,554	$0.0147	$19,256	$435,810
Sept	1,382,605	$0.3180	$439,668	$0.0147	$20,324	$459,992
Oct	1,907,488	$0.3180	$606,581	$0.0147	$28,040	$634,621
Nov	3,968,045	$0.3180	$1,261,838	$0.0147	$58,330	$1,320,168
12 Months	58,634,693		$30,133,317		$325,244	$30,458,561

BSC Revenues

	BSC Appl. Sales mcf (1)	Cost of Gas Rates (Excl GRT) (2)	Cost of Gas Revenues (3) = (1) x (2)	Prior Pd. O/(U) Adjust. Rate (4)	Prior Pd. O/(U) Adjust. Revenue (5) = (1) x (4)	Total Revenues Recovered In Base Rates (6) = (3) + (5)
Dec bef 12/1	4,847,398	$0.3180	$1,541,473	$0.0147	$71,257	$1,612,730
Dec aft 12/1	3,604,909	$0.4605	$1,660,061	($0.0451)	($162,581)	$1,497,480
Jan '24 bef 12/1	-	$0.3180	$0	$0.0147	$0	$0
Jan '24 aft 12/1	11,080,263	$0.4603	$5,100,245	($0.0450)	($498,612)	$4,601,633
Feb	9,813,218	$0.4605	$4,518,987	($0.0451)	($442,576)	$4,076,411
March	9,167,098	$0.4560	$4,180,197	($0.0412)	($377,684)	$3,802,513
April	5,858,386	$0.4498	$2,635,102	($0.0358)	($209,730)	$2,425,372
May (est)	2,741,532	$0.4498	$1,233,141	($0.0358)	($98,147)	$1,134,994
June (est)	1,809,285	$0.4498	$813,816	($0.0358)	($64,772)	$749,044
July (est)	1,614,054	$0.4498	$726,001	($0.0358)	($57,783)	$668,218
Aug (est)	1,575,319	$0.4498	$708,578	($0.0358)	($56,396)	$652,182
Sept (est)	1,684,137	$0.4498	$757,525	($0.0358)	($60,292)	$697,233
Oct (est)	3,207,864	$0.4498	$1,442,897	($0.0358)	($114,842)	$1,328,055
Nov (est)	6,513,293	$0.4498	$2,929,679	($0.0358)	($233,176)	$2,696,503
12 Months	63,516,755		$28,247,702		($2,305,334)	$25,942,368

Miscellaneous Surcharge Revenues — Exhibit APD-4 — Page 5

	Other Monies To Be Refunded				Other Monies Actually Refunded			
	Unauth TCS/TS Penalty Gas (1)	Rate IS Penalty Gas (2)	Transp Bal Penalty + Surcharge (3)	Total (4) = (1) + (2) + (3)	BSC Applicable Sales (5)	Misc. Surcharge (6)	Misc. Surcharge Refund (7) = (5) x (6)	Cumulative Over/(Under) Refund (8) = (4)-(7)
Balance -Nov 30, 2022								$909,194
Dec bef 12/1					4,564,247	$0.0081	$36,970	$872,224
Dec aft 12/1	$32,250	$0	$78,638	$110,888	4,351,517	$0.0131	$57,005	$926,107
Jan '23 bef 12/1					-	$0.0081	$0	$926,107
Jan '23 aft 12/1	$119,025	$0	$72,357	$191,382	11,186,391	$0.0131	$146,542	$970,947
Feb	$300,600	$0	$59,613	$360,213	10,214,894	$0.0131	$133,815	$1,197,345
March	$0	$0	$46,241	$46,241	7,768,307	$0.0139	$107,979	$1,135,607
April	$0	$0	$53,472	$53,472	5,542,730	$0.0145	$80,370	$1,108,709
May	$0	$0	$38,807	$38,807	3,089,037	$0.0145	$44,791	$1,102,725
June	$0	$0	$35,722	$35,722	1,867,451	$0.0146	$27,265	$1,111,182
July	$0	$0	$37,741	$37,741	1,482,063	$0.0147	$21,786	$1,127,137
Aug	$25,425	$0	$44,513	$69,938	1,309,918	$0.0147	$19,256	$1,177,819
Sept	$2,425	$0	$40,002	$42,427	1,382,605	$0.0147	$20,324	$1,199,922
Oct	$75	$0	$34,562	$34,637	1,907,488	$0.0147	$28,040	$1,206,519
Nov	$1,825	$0	$47,542	$49,367	3,968,045	$0.0147	$58,330	$1,197,556
12 Months	$481,625	$0	$589,210	$1,070,835	58,634,693		$782,473	$288,362
Balance at Nov 30, 2023								$1,197,556

Miscellaneous Surcharge Revenues — Exhibit APD-4 — Page 5

	Other Monies To Be Refunded				Other Monies Actually Refunded			
	Unauth TCS/TS Penalty Gas (1)	Rate IS Penalty Gas (2)	Transp Bal Penalty + Surcharge (3)	Total (4) = (1) + (2) + (3)	BSC Applicable Sales (5)	Misc. Surcharge (6)	Misc. Surcharge Refund (7) = (5) x (6)	Cumulative Over/(Under) Refund (8) = (4)-(7)
Balance -Nov 30, 2023								$1,197,556
Dec bef 12/1					4,847,398	$0.0147	$71,257	$1,126,299
Dec aft 12/1	$14,625	$0	$77,745	$92,370	3,604,909	$0.0168	$60,562	$1,158,107
Jan '24 bef 12/1					-	$0.0147	$0	$1,158,107
Jan '24 aft 12/1	$42,075	$0	$93,784	$135,859	11,080,263	$0.0168	$186,148	$1,107,818
Feb	$42,900	$0	$77,086	$119,986	9,813,218	$0.0168	$164,862	$1,062,942
March	$172,050	$0	$60,093	$232,143	9,167,098	$0.0175	$160,424	$1,134,661
April	$8,175	$0	$39,442	$47,617	5,858,386	$0.0186	$108,966	$1,073,312
May (est)	$0	$0	$42,893	$42,893	2,741,532	$0.0186	$50,992	$1,065,213
June (est)	$0	$0	$41,929	$41,929	1,809,285	$0.0186	$33,653	$1,073,489
July (est)	$0	$0	$43,742	$43,742	1,614,054	$0.0186	$30,021	$1,087,210
Aug (est)	$0	$0	$42,518	$42,518	1,575,319	$0.0186	$29,301	$1,100,427
Sept (est)	$0	$0	$41,167	$41,167	1,684,137	$0.0186	$31,325	$1,110,269
Oct (est)	$0	$0	$48,452	$48,452	3,207,864	$0.0186	$59,666	$1,099,055
Nov (est)	$0	$0	$56,540	$56,540	6,513,293	$0.0186	$121,147	$1,034,448
12 Months	$279,825	$0	$665,391	$945,216	63,516,755		$1,108,324	($163,108)
Balance at Nov 30, 2024								$1,034,448

Interest on Revenues to be Returned to Customers

Month	CC Portion of BSC Revenue (1)	Recoverable Cost of Gas (2)	Current Over/(Under) Collection for Interest (3) = (1) - (2)	Interest Rate (4)	Interest Time Factor (5)	Total Interest to be Retd. to Custs. (6) = (3) x (4) x (5)	Interest Given Back To (or Collected From) Customers: BSC Applicable Sales (7)	Interest Refund (8)	Interest Refund (9) = (7) x (8)	Cumulative Total (10) = (6) - (9)
Balance -Nov 30, 2022										$169,529
Dec bef 12/1							4,564,247	$0.0020	$9,128	$160,401
Dec aft 12/1	$4,640,799	$2,616,565	$2,024,234	8.00%	18/12	$242,908	4,351,517	$0.0029	$12,619	$390,690
Jan '23 bef 12/1							-	$0.0020	$0	$390,690
Jan '23 aft 12/1	$6,486,988	$2,646,651	$3,840,337	8.00%	17/12	$435,238	11,186,391	$0.0029	$32,441	$793,487
Feb	$5,922,596	$2,571,134	$3,351,462	8.00%	16/12	$357,489	10,214,894	$0.0029	$29,623	$1,121,353
March	$4,348,698	$2,522,343	$1,826,355	8.00%	15/12	$182,636	7,768,307	$0.0028	$21,751	$1,282,238
April	$3,013,582	$2,214,723	$798,859	8.00%	14/12	$74,560	5,542,730	$0.0027	$14,965	$1,341,833
May	$1,679,509	$2,090,817	($411,308)	8.00%	13/12	($35,647)	3,089,037	$0.0027	$8,340	$1,297,846
June	$845,208	$2,092,909	($1,247,701)	8.00%	12/12	($99,816)	1,867,451	$0.0027	$5,042	$1,192,988
July	$471,296	$2,076,865	($1,605,569)	8.00%	11/12	($117,742)	1,482,063	$0.0027	$4,002	$1,071,244
Aug	$416,554	$2,111,118	($1,694,564)	8.00%	10/12	($112,971)	1,309,918	$0.0027	$3,537	$954,736
Sept	$439,668	$2,098,851	($1,659,183)	8.00%	9/12	($99,551)	1,382,605	$0.0027	$3,733	$851,452
Oct	$606,581	$2,097,714	($1,491,133)	8.00%	8/12	($79,527)	1,907,488	$0.0027	$5,150	$766,775
Nov	$1,261,838	$2,103,338	($841,500)	8.00%	7/12	($39,270)	3,968,045	$0.0027	$10,714	$716,791
12 Months	$30,133,317	$27,243,028	$2,890,289			$708,307	58,634,693		$161,045	$547,262
Balance at Nov 30, 2023										$716,791

Interest on Revenues to be Returned to Customers

Exhibit APD-4 Page 6

Month	CC Portion of BSC Revenue (1)	Recoverable Cost of Gas (2)	Current Over/(Under) Collection for Interest (3) = (1) - (2)	Interest Rate (4)	Interest Time Factor (5)	Total Interest to be Retd. to Custs. (6) = (3) x (4) x (5)	Interest Given Back To (or Collected From) Customers: BSC Applicable Sales (7)	Interest Refund (8)	Interest Refund (9) = (7) x (8)	Cumulative Total (10) = (6) - (9)
Balance -Nov 30, 2023										$716,791
Dec bef 12/1							4,847,398	$0.0027	$13,088	$703,703
Dec aft 12/1	$3,201,534	$2,074,595	$1,126,939	8.50%	18/12	$143,685	3,604,909	$0.0110	$39,654	$807,734
Jan '24 bef 12/1							-	$0.0027	$0	$807,734
Jan '24 aft 12/1	$5,100,245	$2,150,210	$2,950,035	8.50%	17/12	$355,233	11,080,263	$0.0110	$121,883	$1,041,084
Feb	$4,518,987	$2,196,980	$2,322,007	8.50%	16/12	$263,161	9,813,218	$0.0110	$107,945	$1,196,300
March	$4,180,197	$2,150,112	$2,030,085	8.50%	15/12	$215,697	9,167,098	$0.0110	$100,838	$1,311,159
April	$2,635,102	$2,157,726	$477,376	8.50%	14/12	$47,340	5,858,386	$0.0111	$65,028	$1,293,471
May (est)	$1,233,141	$2,120,241	($887,100)	8.50%	13/12	($81,687)	2,741,532	$0.0111	$30,431	$1,181,353
June (est)	$813,816	$2,102,136	($1,288,320)	8.50%	12/12	($109,507)	1,809,285	$0.0111	$20,083	$1,051,763
July (est)	$726,001	$2,123,852	($1,397,851)	8.50%	11/12	($108,916)	1,614,054	$0.0111	$17,916	$924,931
Aug (est)	$708,578	$2,124,638	($1,416,060)	8.50%	10/12	($100,304)	1,575,319	$0.0111	$17,486	$807,141
Sept (est)	$757,525	$2,104,297	($1,346,772)	8.50%	9/12	($85,857)	1,684,137	$0.0111	$18,694	$702,590
Oct (est)	$1,442,897	$2,122,057	($679,160)	8.50%	8/12	($38,486)	3,207,864	$0.0111	$35,607	$628,497
Nov (est)	$2,929,679	$2,178,687	$750,992	8.50%	7/12	$37,237	6,513,293	$0.0111	$72,298	$593,436
12 Months	$28,247,702	$25,605,531	$2,642,171			$537,596	63,516,755		$660,951	($123,355)
Balance at Nov 30, 2024										$593,436

	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			
Month	Supplier Refunds (1)	Interest Rate (2)	Time Factor (3)	Interest (4) = (1) x (2) x (3)	Total (5) = (1)+(4)	BSC Applicable Sales (6)	Supplier Refund Rate (7)	Supplier Refund (8) = (6) x (7)	Cumulative Total (9) = (5)-(8)
Balance	-Nov 30, 2022								$2,041
Dec bef 12/1						4,564,247	$0.0000	$0	$2,041
Dec aft 12/1	$0	6.00%	18/12	$0	$0	4,351,517	$0.0000	$0	$2,041
Jan '23 bef 12/1						-	$0.0000	$0	$2,041
Jan '23 aft 12/1	$0	6.00%	17/12	$0	$0	11,186,391	$0.0000	$0	$2,041
Feb	$0	6.00%	16/12	$0	$0	10,214,894	$0.0000	$0	$2,041
March	$0	6.00%	15/12	$0	$0	7,768,307	$0.0000	$0	$2,041
April	$0	6.00%	14/12	$0	$0	5,542,730	$0.0000	$0	$2,041
May	$0	6.00%	13/12	$0	$0	3,089,037	$0.0000	$0	$2,041
June	$0	6.00%	12/12	$0	$0	1,867,451	$0.0000	$0	$2,041
July	$0	6.00%	11/12	$0	$0	1,482,063	$0.0000	$0	$2,041
Aug	$0	6.00%	10/12	$0	$0	1,309,918	$0.0000	$0	$2,041
Sept	$0	6.00%	9/12	$0	$0	1,382,605	$0.0000	$0	$2,041
Oct	$0	6.00%	8/12	$0	$0	1,907,488	$0.0000	$0	$2,041
Nov	$0	6.00%	7/12	$0	$0	3,968,045	$0.0000	$0	$2,041
12 Months	$0			$0	$0	58,634,693		$0	$0
Balance at Nov 30, 2023									$2,041

Supplier Refunds : Including Interest - Summary Sheet Exhibit APD-4 Page 7

	Refunds and Interest to be Returned to Customers					Refunds and Interest Actually Returned to Customers			
Month	Supplier Refunds (1)	Interest Rate (2)	Time Factor (3)	Interest (4) = (1) x (2) x (3)	Total (5) = (1)+(4)	BSC Applicable Sales (6)	Supplier Refund Rate (7)	Supplier Refund (8) = (6) x (7)	Cumulative Total (9) = (5)-(8)
Balance	-Nov 30, 2023								$2,041
Dec bef 12/1						4,847,398	$0.0000	$0	$2,041
Dec aft 12/1	$0	6.00%	18/12	$0	$0	3,604,909	$0.0000	$0	$2,041
Jan '24 bef 12/1						-	$0.0000	$0	$2,041
Jan '24 aft 12/1	$0	6.00%	17/12	$0	$0	11,080,263	$0.0000	$0	$2,041
Feb	$0	6.00%	16/12	$0	$0	9,813,218	$0.0000	$0	$2,041
March	$0	6.00%	15/12	$0	$0	9,167,098	$0.0000	$0	$2,041
April	$0	6.00%	14/12	$0	$0	5,858,386	$0.0000	$0	$2,041
May (est)	$0	6.00%	13/12	$0	$0	2,741,532	$0.0000	$0	$2,041
June (est)	$0	6.00%	12/12	$0	$0	1,809,285	$0.0000	$0	$2,041
July (est)	$0	6.00%	11/12	$0	$0	1,614,054	$0.0000	$0	$2,041
Aug (est)	$0	6.00%	10/12	$0	$0	1,575,319	$0.0000	$0	$2,041
Sept (est)	$0	6.00%	9/12	$0	$0	1,684,137	$0.0000	$0	$2,041
Oct (est)	$0	6.00%	8/12	$0	$0	3,207,864	$0.0000	$0	$2,041
Nov (est)	$0	6.00%	7/12	$0	$0	6,513,293	$0.0000	$0	$2,041
12 Months	$0			$0	$0	63,516,755		$0	$0
Balance at Nov 30, 2024									$2,041

Month	Gross Cost of Storage (1)	Total Exclusions (2)	Net Cost of Storage (3) = (1) - (2)	Allocation Factor (4)	Recoverable Cost (5) = (3) x (4)
Balance	-Nov 30, 2024				
Dec (est)	$2,232,000	$37,628	$2,194,372	0.99975996	$2,193,845
Jan '25 (est)	$2,232,000	$42,599	$2,189,401	0.99949618	$2,188,298
Feb (est)	$2,168,000	$40,659	$2,127,341	1.00000000	$2,127,341
March (est)	$2,232,000	$40,853	$2,191,147	0.99947111	$2,189,988
April (est)	$2,218,000	$31,587	$2,186,413	0.99925326	$2,184,780
May (est)	$2,243,000	$27,623	$2,215,377	0.99966442	$2,214,634
June (est)	$2,218,000	$24,886	$2,193,114	0.99991335	$2,192,924
July (est)	$2,243,000	$24,645	$2,218,355	0.99990309	$2,218,140
Aug (est)	$2,243,000	$24,296	$2,218,704	0.99996921	$2,218,636
Sept (est)	$2,218,000	$23,205	$2,194,795	0.99986070	$2,194,489
Oct (est)	$2,243,000	$26,322	$2,216,678	0.99980228	$2,216,240
Nov (est)	$2,301,000	$31,082	$2,269,918	0.99968647	$2,269,206
12 Months	$26,791,000	$375,385	$26,415,615		$26,408,521

BSC Revenues

	BSC Appl. Sales mcf (1)	Cost of Gas Rates (Excl GRT) (2)	Cost of Gas Revenues (3) = (1) x (2)
Dec bef 12/1 (est)	5,379,003	$0.4498	$2,419,476
Dec aft 12/1 (est)	5,104,340	$0.3874	$1,977,421
Jan '25 bef 12/1 (est)	-	$0.4498	$0
Jan '25 aft 12/1 (est)	13,017,998	$0.3874	$5,043,173
Feb (est)	11,165,429	$0.3874	$4,325,487
March (est)	9,180,357	$0.3874	$3,556,470
April (est)	5,012,713	$0.3874	$1,941,925
May (est)	2,752,522	$0.3874	$1,066,327
June (est)	1,823,243	$0.3874	$706,324
July (est)	1,630,199	$0.3874	$631,539
Aug (est)	1,591,425	$0.3874	$616,518
Sept (est)	1,701,174	$0.3874	$659,035
Oct (est)	3,241,308	$0.3874	$1,255,683
Nov (est)	6,568,277	$0.3874	$2,544,550
12 Months	68,167,987		$26,743,928

Interest on Revenues to be Returned to Customers

Month	CC Portion of BSC Revenue (1)	Recoverable Cost of Gas (2)	Current Over/(Under) Collection for Interest (3) = (1) - (2)
Balance -Nov 30, 2024			
Dec bef 12/1 (est)			
Dec aft 12/1 (est)	$4,396,897	$2,193,845	$2,203,052
Jan '25 bef 12/1 (est)			
Jan '25 aft 12/1 (est)	$5,043,173	$2,188,298	$2,854,875
Feb (est)	$4,325,487	$2,127,341	$2,198,146
March (est)	$3,556,470	$2,189,988	$1,366,482
April (est)	$1,941,925	$2,184,780	($242,855)
May (est)	$1,066,327	$2,214,634	($1,148,307)
June (est)	$706,324	$2,192,924	($1,486,600)
July (est)	$631,539	$2,218,140	($1,586,601)
Aug (est)	$616,518	$2,218,636	($1,602,118)
Sept (est)	$659,035	$2,194,489	($1,535,454)
Oct (est)	$1,255,683	$2,216,240	($960,557)
Nov (est)	$2,544,550	$2,269,206	$275,344
12 Months	$26,743,928	$26,408,521	$335,407

Exhibit APD-5

PECO ENERGY COMPANY

GAS SERVICE TARIFF

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 3.

Issued May 31, 2024 Effective December 1, 2024

.

ISSUED BY: D. Velazquez - President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE.

LIST OF CHANGES MADE BY THIS SUPPLEMENT

SALES SERVICE COSTS (SSC) – 7th Revised Page No. 43
The Commodity Charges are decreased. The Gas Cost Adjustment is increased.

SALES SERVICE COSTS (SSC) – 4th Revised Page No. 44
The Off-System Sales Sharing Mechanism is extended through November 30, 2027.

MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – 7th Revised Page No. 47 and 7th Revised Page No. 48
The Merchant Function Charges are decreased and the Prices to Compare are increased.

BALANCING SERVICE COSTS (BSC) – 7th Revised Page No, 49
The Balancing Service Cost is decreased.

GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS – 4th Revised Page No. 71
The Balancing Charge is decreased.

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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 **$4.3386** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, **$4.3261** per Mcf for Rate Schedules GC and **$4.3222** **(D)** 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 **0.1493** 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.

(D) Denotes Decrease
(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, 2027 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.

(C) Denotes Change

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 **$0.0181**per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, at **$0.0056** per Mcf for Rate Schedule GC and at **$0.0017** 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-2022-3031113. 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. **(D)** **(D)**

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 **(0.42%),** Rate Schedule GC **(0.13%)** and Rate Schedules OL, L and MV-F (**0.04%)** as determined at Docket No R-2022-3031113, the Company's 2022 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	$4.2819 per Mcf	**(D)**
Gas Cost Adjustment	$0.1493 per Mcf	**(I)**
Gas Procurement Charge	$0.0386 per Mcf	
Merchant Function Charge	$0.0181 per Mcf	**(D)**
Price to Compare	$4.4879 per Mcf	**(I)**

COMPONENT	RATES GC	
Commodity Charge excluding GPC and MFC	$4.2819 per Mcf	**(D)**
Gas Cost Adjustment	$0.1493 per Mcf	**(I)**
Gas Procurement Charge	$0.0386 per Mcf	
Merchant Function Charge	$0.0056 per Mcf	**(D)**
Price to Compare	$4.4754 per Mcf	**(I)**

(D) Denotes Decrease

() Denotes crease

COMPONENT	**RATES OL, L and MV-F**	
Commodity Charge excluding GPC and MFC	$4.2819 per Mcf	**(D)**
Gas Cost Adjustment	$0.1493 per Mcf	**(I)**
Gas Procurement Charge	$0.0386 per Mcf	
Merchant Function Charge	$0.0017 per Mcf	**(D)**
Price to Compare	$4.4715.per Mcf	**(I)**

(D) Denotes Decrease

(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 **$0.3248** 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. **(D)**

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.

(D) Denotes Decrease

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 **$0.0225** 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) **(C)**
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.

(C) Denotes Change

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PECO ENERGY COMPANY

GAS SERVICE TARIFF

COMPANY OFFICE LOCATION

2301 Market Street

Philadelphia, Pennsylvania 19103

For List of Communities Served, See Page 3.

Issued May 31, 2024 Effective December 1, 2024

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ISSUED BY: D. Velazquez - President & CEO
PECO Energy Distribution Company
2301 MARKET STREET
PHILADELPHIA, PA. 19103

NOTICE.

Supplement No. 15 to
Gas-Pa. P.U.C. No. 5
Fourteenth Revised Page No. 1
PECO Energy Company Supersedes Thirteenth Revised Page No. 1

LIST OF CHANGES MADE BY THIS SUPPLEMENT

SALES SERVICE COSTS (SSC) – 7th Revised Page No. 43
The Commodity Charges are decreased. The Gas Cost Adjustment is increased.

SALES SERVICE COSTS (SSC) – 4th Revised Page No. 44
The Off-System Sales Sharing Mechanism is extended through November 30, 2027.

MERCHANT FUNCTION CHARGE AND PRICE TO COMPARE – 7th Revised Page No. 47 and 7th Revised Page No. 48
The Merchant Function Charges are decreased and the Prices to Compare are increased.

BALANCING SERVICE COSTS (BSC) – 7th Revised Page No, 49
The Balancing Service Cost is decreased.

GAS TRANSPORTATION SERVICE - GENERAL TERMS AND CONDITIONS – 4th Revised Page No. 71
The Balancing Charge is decreased.

Issued May 31, 2024 Effective December 1, 2024

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Revised DSIC rate from 0.00% to 0.07%.¶
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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 $4.3386 per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, $4.3261 per Mcf for Rate Schedules GC and $4.3222 (D) 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 0.1493 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.

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(I) Denotes Increase

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"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, 2027 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. **(C)**

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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 **$0.0181** per Mcf (1,000 cubic feet) for Rate Schedules GR and CAP, at **$0.0056** per Mcf for Rate Schedule GC and at **$0.0017** 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-2022-3031113. 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. **(D)** **(D)**

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 **(0.42%),** Rate Schedule GC **(0.13%)** and Rate Schedules OL, L and MV-F (**0.04%)** as determined at Docket No R-2022-3031113, the Company's 2022 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	$4.2819 per Mcf	(D)
Gas Cost Adjustment	$0.1493 per Mcf	(I)
Gas Procurement Charge	$0.0386 per Mcf	
Merchant Function Charge	$0.0181 per Mcf	(D)
Price to Compare	$4.4879 per Mcf	(I)

COMPONENT	RATES GC	
Commodity Charge excluding GPC and MFC	$4.2819 per Mcf	(D)
Gas Cost Adjustment	$0.1493 per Mcf	(I)
Gas Procurement Charge	$0.0386 per Mcf	
Merchant Function Charge	$0.0056 per Mcf	(D)
Price to Compare	$4.4754 per Mcf	(I)

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COMPONENT	RATES OL, L and MV-F	
Commodity Charge excluding GPC and MFC	$4.2819 per Mcf	(D)
Gas Cost Adjustment	$0.1493 per Mcf	(I)
Gas Procurement Charge	$0.0386 per Mcf	
Merchant Function Charge	$0.0017 per Mcf	(D)
Price to Compare	$4.4715 per Mcf	(I)

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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 **$0.3248** 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. **(D)**

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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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Supplement No. 15 to
Gas-Pa. P.U.C. No. 5
Fourth Revised Page No. 71
PECO Energy Company **Supersedes Third Revised Page No. 71**

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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 **$0.0225** 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) **(C)**

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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.

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Issued May 31, 2024 Effective December 1, 2024

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