COMMONWEALTH OF PENNSYLVANIA

September 12, 2022

E-FILED

Rosemary Chiavetta, Secretary
Pennsylvania Public Utility Commission
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. PECO Energy Company – Gas Division / Docket No. R-2022-3031113

Dear Secretary Chiavetta:

The Pennsylvania Public Utility Commission's Implementation Order at *Electronic Access to Pre-Served Testimony*, Docket No. M-2012-2331973, requires that all testimony furnished to the court reporter during a proceeding must subsequently be provided to the Secretary's Bureau.

As such, this letter will confirm that the Office of Small Business Advocate ("OSBA") has e-filed the **Public Version** of Direct Testimony and Exhibits RDK-1 and RDK-2 and RDK-3, of Robert D. Knecht, labeled OSBA Statement No.1 and the Rebuttal Testimony and Exhibits -RDK-1R and RDK-2R, of Robert D. Knecht labeled OSBA Statement No. 1-R and the Surrebuttal Testimony and Exhibit RDK-1-S and RDK-2S, of Robert D. Knecht labeled OSBA Statement No. 1-SR on behalf of the OSBA, in the above-captioned proceeding.

All known parties were previously served with the aforementioned Testimony. If you have any questions, please contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: Robert D. Knecht
Parties of Record (Cover Letter and Certificate of Service Only)

COMMONWEALTH OF PENNSYLVANIA

June 22, 2022

The Honorable F. Joseph Brady
Administrative Law Judge
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107

Re: Pennsylvania Public Utility Commission v. PECO Energy Company – Gas Division / Docket No. R-2022-3031113

Dear Judge Brady:

Enclosed please find the Direct Testimony and Exhibits of Robert D. Knecht, **Public Version**, labeled OSBA Statement No. 1, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures cc:
PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)
Robert D. Knecht
Parties of Record

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3031113**
PECO Energy Company (Gas Division)	:	

Direct Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

******* PUBLIC VERSION *******

Topics:

Cost Allocation
Revenue Allocation
Rate Design

Date Served: June 22, 2022

Date Submitted for the Record: August 11, 2022

DIRECT TESTIMONY OF ROBERT D. KNECHT

1. Introduction and Overview

Q. Please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am an independent consultant. Much of my practice involves analysis and the preparation of expert testimony in the field of regulatory economics. For 32 years, I was a Principal of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140, and I served as Treasurer of that firm for 15 years. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and an M.S. degree in Management from the Sloan School of Management at M.I.T. in 1982, with concentrations in applied economics and finance.

I am appearing in this proceeding on behalf of the Pennsylvania Office of Small Business Advocate ("OSBA"). I have represented the OSBA before the Pennsylvania Public Utility Commission in a variety of matters since 1994. I presented testimony in the most recent PECO Energy Company – Gas Division ("PECO Gas" or "the Company") base rate case at Docket No. R-2020-3018929. My résumé and a listing of the expert testimony that I have filed in utility regulatory proceedings during the past five years are attached in Exhibit RDK-1.

Q. What is the purpose of this testimony?

A. I was retained by the OSBA to review certain aspects of the PECO Gas base rates filing, and to evaluate whether the Company's proposed rate increases and tariff changes for small businesses are consistent with sound regulatory and economic principles.

In preparing this testimony, I relied in substantial part on analyses that I prepared for my direct testimony in the Company's last base rates proceeding at Docket No R-2020-3018929, particularly with respect to the intra-class customer consumption patterns that influence rate design. Because the load patterns for rate classes with many customers will change only gradually over time, my analysis from less than two years ago remains relevant to this

proceeding. I also borrowed some substantial portions of the verbiage from that testimony where that also remain relevant, with only minor editing.

Q. Please summarize your current conclusions and recommendations.

A. As detailed herein, I conclude the following:

- The Company's class cost of service study ("COSS") relies on (a) an allocation method for mains that is consistent with the Commission's decision in the Company's last base rates case, and (b) design day demand estimates for several rate classes that are substantially superior to those presented in the Company's last base rates case. The COSS does include errors related to Distribution System Improvement Charge ("DSIC") and purchased gas cost ("PGC") revenues which the Company has acknowledged but not yet corrected. Moreover, I identify cost allocation issues in this testimony that merit additional investigation.

- The Company's negotiated Rate NGS service allows the Company to discount its rates to meet competitive conditions related to customers' potential to bypass the utility or to use alternative fuels. The Company's proof of revenues indicates that it has about 8.3 Bcf of volume subject to negotiated rates (about 9 percent of system total), with a revenue shortfall of $6.5 million at the Company's proposed rates in the TS-F and TS-I rate classes. As a general rule, it is not reasonable to assign the entire shortfall from flex rate customers to their respective rate classes for revenue allocation purposes, because the competitive rate discounts benefit all customer classes. However, for PECO Gas, it appears that the allocated costs for the TS-F and TS-I classes are substantially reduced by the "direct assignment" method for allocating distribution plant costs to at least one of these flex rate customers. As such, I have made no adjustment to reassign revenue shortfalls to other rate classes. The Company should consider treating flex rate customers as a separate rate class for cost and revenue allocation purposes in the future.

- The Company has updated its competitive analysis of four of the current Rate NGS customers, to evaluate whether the discounts reasonably reflect competitive conditions. For those customers, the Company's analysis does not demonstrate

that the magnitude of the rate discounts are justified by competitive considerations. However, the revenue shortfalls in question, however, represent only a small percentage of the overall $6.5 million shortfall from Rate NGS customers.

- The Company's revenue allocation proposal is consistent with its cost allocation methodology, as evaluated using an unbiased revenue-cost ratio metric. I therefore do not propose an alternative revenue allocation in this testimony. If necessary, however, I will develop a revenue allocation proposal in surrebuttal testimony that reflects PECO's corrections to its COSS to reflect the revenue errors.

- In the last base rates case, the Company and the Commission generally accepted my proposals for Rate GC tariff design, by holding the customer charge at its then current levels and narrowing the differential in the commodity block charges. My analysis from that testimony, combined with updated analysis in this proceeding, justifies continuing this pattern in this proceeding. I therefore recommend that for rate design for Rate GC, no change be made to the Rate GC customer charge, and the narrowing of the block differential for the Rate GC commodity charges should continue. The Company may wish to consider establishing differentiated customer charges for Rate GC to reflect differences in cost causation between smaller and larger customers within the class, as other Pennsylvania natural gas distribution companies ("NGDCs") have done.

- The Company has not prepared any cost justification for the large volumetric rate differentials in Rates TS-F and TS-I between large and smaller customers, and it declined to provide the cost information necessary for me to prepare that evaluation. Based on my analysis of class load factors in the last base rates case, I recommend that those differentials be narrowed in this proceeding. I also recommend that the Company's proposed large increases to customer charges for the smaller TS-F and TS-I customers be reduced, as the Company has no cost justification for those proposals.

Q. How is your testimony organized?

A. Sections 2 through 4 address cost allocation, revenue allocation, and rate design respectively. Appendix A provides an explanation as to why the indexed rate of return can be an unreliable metric for evaluating progress toward cost-based rates. Exhibit RDK-2 presents a listing of the Company's responses to interrogatories to which I make reference in this testimony. Exhibit RDK-3 lists my electronic workpapers. Executable MS Excel versions of those workpapers are being circulated with this testimony.

2. <u>Cost Allocation</u>

Q. What is a utility cost allocation study?

A. A utility cost allocation study, in this case the Company's gas class cost of service study ("COSS"), is an analytical tool that assigns the utility's test year total costs (i.e., the "revenue requirement") among the various utility rate classes. Pennsylvania electric and gas utilities generally use an "embedded cost" approach to cost allocation, in which accounting book costs are directly assigned among the rate classes, rather than a marginal cost approach. It is generally agreed that costs should, to the extent practicable, be assigned among rate classes based on "cost causation," such that costs caused by a particular class of customers are assigned to that class. A cost allocation study generally involves a three-step process, in which costs are (a) segregated by function ("functionalization"), (b) further segregated by cost causation factor, notably throughput, peak demand, "excess" demand, and customer count ("classification"), and (c) allocated among the rate classes based on each class' contribution to the cost causation factor ("allocation").

Q. What purpose does the COSS serve in a utility rate proceeding?

A. The COSS informs both the assignment of the rate increase among customer classes ("revenue allocation") and the design of rates to recover the revenues assigned to each rate class. Revenue allocation is often used to move rate revenue more into line with allocated costs from the COSS. For rate design, classified costs, such as customer-related and demand-related costs, are used to inform the development of specific rate charges, such as monthly customer and demand charges.

Q. Please describe the various rate classes used in the Company's COSS.

A. The Company's COSS includes the following rate classes:

Rate GR, General Service Residential: Eligible customers include single-family residences, and multi-family master-metered residences of up to five units. Customers can choose between utility sales service and retail "Gas Choice" transportation service.

Rate GC, General Service Commercial and Industrial: Service is provided to commercial and industrial ("C&I") customers, where "commercial" includes a variety of entities including but not limited to commercial businesses, multi-family master-metered residences (over five units), government entities, institutions and office buildings.[1] For cost and revenue allocation purposes, the Company includes Rate OL Outdoor Lighting Service in the GC class.[2] Rate GC also includes a small number of transportation customers who purchase backup gas supplies through "Standby Sales Service. " GC customers can take utility sales or retail "Gas Choice" supply service. This is an extremely diverse class, in terms of the size of customers. Based on data from the Company's last base rates case, there are about 44,450 customers in the class. Of these, about 3,700 customers have annual load below 85 mcf (the average residential usage) while nearly 2,900 customers have annual load above 18,000 mcf (which is the Company's cutoff for the highest volume rate class).[3]

Rate L, Large High Load Factor Service: This tariff category appears to have been originally aimed at C&I customers who use gas at a high load factor, implying that the gas is used for process applications rather than for space heating.[4] In practice, however, there appear to be only five "regular service" customers remaining on this tariff, while the balance of the load relates to be Rate TS-F and TS-I transportation service customers who use Rate L for their Standby Sales Service volumes.

---

[1] See PECO Gas tariff page 18.

[2] There appear to be only three Rate OL customers with minimal volumes and revenues. See Attachment OCA-1-20(a), "JAB-4 OL" tab.

[3] See OSBA Statement No. 1 at Docket No. R-2020-3018929 at 15.

[4] "Load factor" is industry jargon for the ratio of average demand to peak demand. If a customer uses the same amount of gas on every day of the year, its average demand and peak demand are the same, and the load factor is 1.0 (or 100.0%). Customers who use gas primarily for space heating have relatively low load factors, since the demand on extremely cold days tends to be 4 to 5 times the customer's use on the average day of the year, implying load factors of 0.20 to 0.25 (20 to 25 percent).

Rate MV-F, Motor Vehicle Service - Firm: This tariff provides service to customers who use gas "exclusively as fuel for motor vehicles."[5] The Company forecasts that there will be 15 of these customers in the test year, with relatively high average annual volume of some 31,000 mcf.[6] Because these loads are not temperature sensitive, the class load factor is high and the unit cost to serve is relatively low. MV-F customers can take utility gas supply or Gas Choice service.

Rate MV-I, Motor Vehicle Service – Interruptible: Service is provided to customers whose sole use of gas is for motor vehicles and who maintain alternative fuel capability. The Company forecasts that there is only one of these customers remaining in the test year, with relatively low volumes. The service is priced at "flex" rates, which are reportedly based on the cost of unleaded gasoline and diesel, but the rates are capped at the tail block volumetric cost for Rate GC inclusive of purchased gas costs. Because prices are bundled, MV-I customers must take utility gas supply.

Rate IS, Interruptible Service: This tariff provides interruptible gas sales service to customers with alternative fuel capability whose summer month gas consumption is at least 3,000 mcf (or who also take service under another tariff). The Company forecasts that there is only one remaining customer for this service, with average annual use of some 11,000 mcf. The base rate tariff charge for this customer in the Company's forecast is lower than that for the largest of the TS-I interruptible transportation service customers (with volume over 18,000 mcf).[7]

Rate TCS, (Interruptible) Temperature Controlled Service: This tariff provides interruptible service to customers with dual-fuel equipment with rated input of at least 2.1 million BTU per hour and estimated fuel usage of 5,000 mcf during the winter months of

[5] PECO Gas tariff page 59.

[6] It is unclear why PECO Gas treats MV-F customers as a low-volume customer class (see, e.g., PECO Gas tariff page 6), since the average customer volume exceeds that for Rate TS-F. It is similarly unclear why MV-I customers are not treated as low-volume customers, as their average annual usage is below that of the average Rate GC customer.

[7] Offering a lower distribution rate to a customer because it takes utility gas supply service is a textbook example of undue discrimination. Nevertheless, the Commission explicitly approved continuation of this rate class. Cite decision.

December through March.[8] The Company forecasts that 22 customers will take service under this tariff in the fully projected future test year ("FPFTY") (down from 31 in the Company's last base rates case). Like MV-I and IS, the tariff rate is a flex rate based on the market price of alternative fuels, and customers take utility sales service.

Rate TS-F, Transportation Service – Firm: This tariff offers firm service to non-Choice transportation customers. These customers may also take standby gas supply service, for which they pay Rate GC or Rate L delivery rates. In addition, some customers who would otherwise take Rate TS-F service take negotiated rate service under Rate NGS, if they can "document a viable, currently available competitive alternative" to regular rate service. These volumes and revenues are included with TS-F for cost and revenue allocation purposes. This class also includes customers in a wide range of sizes. Based on my analysis in the last base rates case, roughly 20 percent of the customers have annual usage below 2,000 mcf, while the largest customers have loads in excess of 100,000 mcf.

Rate TS-I, Transportation Service – Interruptible: This tariff provides basic interruptible transportation service to a customer who arranges for its own gas supply and is willing to accept being interrupted. A showing of alternative fuel capability does not appear to be required. The Company does not consider the peak demands for these customers in its gas supply planning, nor (presumably) does it consider the peak demands of this class in distribution system planning. Rate TS-I customers may obtain standby gas supply service from the Company and are required to pay regular rate tariff delivery charges (Rate L or Rate GC) to deliver those standby supplies. However, standby gas supplies (even delivered at the firm tariff rates) are considered to be interruptible.[9]

Q. Do you agree with the Company's definition of rate classes for cost allocation purposes?

A. No. The Company's COSS has nine rate class categories, four of which represent over 99.8 percent of costs, and five of which represent only 44 customers and less than 0.2 percent of

[8] According to the Company's response to OSBA-II-21(f), it does not appear that the Company enforces the minimum winter volume levels after initial eligibility is determined.

[9] OSBA Statement No. 1 at Docket No. 2020-3018929 at 18.

costs. Meanwhile, the Company aggregates an enormous number of customers with a wide range of sizes into a single class for cost allocation, namely the GC class. Beyond the GC class, additional detail would be welcome is the TS-F and TS-I rate classes. The Company's tariffs for those classes have substantially different tariff charges for customers above and below annual volumes of 18 million cubic feet ("mmcf"). For example, the Company's volumetric charge for Rate TS-F customers below 18 mmcf per year is more than double the volumetric charge for TS-F customers over 18 mmcf per year. In effect, PECO Gas is setting separate rates for customers under 18 mmcf per year and customers over 18 mmcf per year.

Moreover, the TS-F and TS-I customer classes represent a substantial percentage (28 percent) of the Company's annual throughput, and a not-insignificant amount of base rate revenues (7 percent). As filed, the Company has no cost allocation basis for the rate differentials in the TS-F and TS-I rate classes.

Thus, despite the appearance of a wide array of rate classes, the information from the COSS is of only limited usefulness for revenue allocation and rate design purposes, particularly for the heterogenous non-residential rate classes.

Q. How do you address this issue?

A. I developed a working model of the Company's electronic cost allocation study, beginning with a near replication of the Company's results.[10] I intended to modify my model to segregate costs for both TS-F and TS-I classes between smaller and larger customers in each class. However, the Company declined to provide the details necessary for me to do so.[11] In the Company's last base rates case, facing the same conditions, I attempted to address the rate design issues within the TS-F and TS-I classes by reviewing the information available regarding load patterns. Nevertheless, I recommend that the Commission require the Company to separately allocate costs to the smaller and larger TS-F and TS-I customer groups in the future.

[10] See RDK WP1.

[11] OSBA-I-1(b).

Q. Turning to the issues of cost allocation methodology, what are the most important cost allocation issues for an NGDC like PECO Gas?

A. A COSS allocates rate base and associated capital costs, distribution expense, customer accounts/service expense, expense, administrative/general ("A&G") expense and taxes.[12] Often, costs are allocated on a derivative basis, based on costs already allocated. For example, depreciation, income taxes and return are often allocated in the same manner as, or in proportion to, rate base. General plant and A&G costs are typically allocated based on some combination of overall plant allocations or O&M expense or labor allocations. Thus, the overall results of a COSS are substantially driven by the allocation of a few large asset accounts. These "big ticket" issues for cost allocation are generally:

- Classification of mains costs, potentially into peak demand, throughput and/or customer components. For PECO Gas, mains represent 50 percent of the Company's gross plant.
- Definition and derivation of the peak-demand allocation factor, including the treatment of interruptible load in the allocator.
- Allocation of meters and services costs.

Q. Please describe the basic issues involved in gas utility mains cost causation.

A. Gas distribution mains are installed to meet two basic objectives: (a) to interconnect the customer with the interstate pipeline system (or other gas supply sources), and (b) to be able to transport sufficient gas to meet the demand of customers downstream under extreme peak conditions.

However, having stated that, it is not easy to develop an analytical model capable of reflecting these cost causation factors. Ideally, the cost of any particular segment of main would only be allocated to those specific customers who are served downstream from that segment. In practice, undertaking such an analysis can be detailed, costly and time

[12] Distribution, customer accounts/service and A&G expenses are collectively called operating and maintenance ("O&M") expense.

consuming. Nevertheless, with the significant improvements in computer modeling of gas distribution systems, one would expect that this approach could be implemented in 2022. Alas, to my knowledge, no Pennsylvania natural gas utility has recently attempted such an approach.[13] And without significant efforts on the part of the utility, it is impossible for outsiders to conduct this type of analysis.

Q. What are the more traditional approaches to mains cost classification?

A. In place of the detailed modeling approaches various analytical models are used. These methods attempt to address the following questions:

- What causation factors best correlate with mains costs?
- Are mains costs causally related to the number of customers? And, if so, how should the "customer component" of mains costs be derived?
- How should mains costs that are not causally related to number of customers be allocated among the various rate classes?

Regarding the first question, the traditional cost allocation parameters include throughput, peak demand, excess peak over average demand, and number of customers. As a matter of arithmetic, a throughput allocation factor is equivalent to an "energy" allocator, a "commodity" allocator, a "volumetric" allocator, and an "average demand" allocator.[14]

Regarding the second question, the common-sense argument (to which I generally subscribe) is that more footage of mains must be installed to interconnect many small customers than to connect one larger customer with the same aggregate load. This approach is particularly appealing for small to medium business customers who are often more geographically concentrated in commercial areas, thereby requiring less mains footage. This conceptual

[13] UGI Gas did prepare such an analysis in 1995. Unfortunately, in more recent base rates proceedings, UGI Gas abandoned that approach.

[14] Average demand is generally measured as annual throughput divided by 365 days. As such, it is arithmetically equivalent to annual throughput when used as an allocation factor. The ratio of average demand to peak day demand is generally referred to as load factor. High load factor customers typically use gas for manufacturing process applications; low load factor customers often rely on gas primarily for heating purposes.

argument is supported by aggregate industry statistical analysis.[15] Consequently, mains footage is causally related to the number of customers, and therefore mains costs are partially customer-related.

Commission precedent indicates that the Commission has rejected the use of a customer component for gas distribution utilities in Pennsylvania, in the most recent cases of which I am aware. However, recent Commission precedent for electric distribution utilities, where the conceptual arguments regarding cost causation are similar, supports the recognition of a customer component for joint-use distribution plant allocation.[16]

In this proceeding, the Company's COSS does not include a customer component for mains costs.

Q. Have you incorporated a customer component into your mains cost allocation in this proceeding?

A. While I believe that the economies associated with attaching fewer larger customers provide conceptual support for including a customer component in mains allocation, I have not done so in this proceeding for reasons of Commission precedent for gas distribution utilities.

Q. If there is no customer component of mains costs, what methods are in general use for allocating those costs?

A. The traditional allocation methods include three general approaches: a peak demand method; a peak-and-average ("P&A") method; and an average-and-excess ("A&E") method.

Because mains must be sized to meet the design day peak demand of all downstream customers, I conclude that the peak demand method is most consistent with cost causation.

---

[15] See, for example, a report prepared by Black & Veatch for Gaz Métropolitain, at http://publicsde.regie-energie.qc.ca/projets/235/DocPrj/R-3867-2013-B-0005-Demande-Piece-2013_11_15.pdf, pages 12-16.

[16] For example, PPL Electric used a minimum system methodology for many years for secondary system plant, and subsequently expanded the minimum system method to primary system plant in its 2010 and 2012 base rates cases. This methodology was fully litigated and explicitly approved by the Commission. *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2010-2161694, at 46 (Order entered December 21, 2010), and *Pa. PUC v. PPL Electric Utilities Corp.*, Docket No. R-2012-2200597, at 113 (Order entered December 28, 2011.)

Other analysts, however, favor the P&A method, in which allocation factors represent a weighted average (most often 50/50) of a throughput allocator and a peak demand allocator. Relative to the peak demand method, this approach assigns more cost to customers who use gas on a more level basis throughout the year (high load factor customers) and less cost to customers whose gas use is primarily for heating purposes. I respectfully disagree with the use of this allocation method, because mains costs are not causally related to average use. A main that serves a high load factor industrial customer with a design day load of 10 mcf per day and a set of low load factor residential and small commercial customers with a combined designed day demand of 10 mcf per day must be sized to meet maximum demand of 20 mcf per day. Each class is equally responsible for the cost of that main. A peak demand allocator would reflect that reality. By contrast, the P&A allocator would assign a majority of the costs to the higher load factor industrial customer.

The A&E allocation factor is a weighted average of average demand (i.e., throughput) and "excess" demand. Excess demand is measured as the difference between peak demand and average demand. Because this allocation factor consists of an average demand component and a "peak minus average" demand component, it is typically more similar in magnitude to a peak demand allocator than to a P&A allocator. However, this observation depends on the weighting factor used to derive the A&E factor. Under specific conditions, namely when the weighting factor is based on the system load factor and there is no diversity of demand across classes, the P&A allocator is arithmetically identical to the A&E factor.

In this proceeding, the Company uses the A&E allocation method (denoted average and extra), and it generally relies on a system load factor weighting of the average and the excess components. As such, the A&E allocator used by the Company produces results that are nearly identical to those that would result from a peak demand allocator. As shown in my workpapers, the Company's A&E allocation factor is arithmetically equivalent to an allocator that is weighted at 99.2 percent based on non-coincident peak demands and 0.8 percent based on average demands.

Q. Please review Commission precedent with respect to mains cost allocation methods.

A. In a case involving PPL Gas at Docket No. R-00061398, the Commission approved an allocation of all mains costs using a variant on the A&E allocation method advanced by the utility expert witness. In that proceeding, the approved weighting was 40 percent to average demand and 60 percent to excess demand. This weighting was not based on system load factor.[17] Also, in a case involving the Philadelphia Gas Works ("PGW") at Docket No. R-00061931, PGW proposed to classify some mains costs as customer-related and the balance as demand-related, and proposed to allocate demand-related costs using a peak demand allocator. However, the Commission concluded that no mains costs should be classified as customer-related, and that mains costs should be allocated using a variant of the A&E allocation method advanced by the expert from what was then the Commission's Office of Trial Staff. In the PGW proceeding, the approved weighting was 50 percent to average demand and 50 percent to excess demand. This weighting was also not based on system load factor.[18] Moreover, the Commission explicitly indicated that the allocation should reflect "both annual and peak" demand. Going further back, the Commission explicitly approved the use of the P&A method in a proceeding involving National Fuel Gas Distribution at Docket No. R-00942991.

More recently, in the Columbia Gas proceeding at Docket No. R-2020-3018835, the Commission adopted the OCA proposal to rely on a 50/50 weighted P&A allocation factor. The Commission indicated:

> Furthermore, distribution mains exist and are related to both annual demands and peak demands. Both annual and peak demands must be recognized in the allocation of distribution mains cost if the allocation is to be in accord with the principle of cost-causality. It is not reasonable to allocate distribution mains investment based solely on design peak day demands as in Columbia's Customer-Demand ACCOSS. The basic reason Columbia invests in its distribution system is to meet the annual demands for gas by customers. Additionally, a portion of the total cost of distribution service is related to

[17] PA PUC et al. v. PPL Gas Utilities Corporation, Docket No. R-00061398 (Order entered February 8, 2007), pages 112 – 114.

[18] See PA PUC v. Philadelphia Gas Works, Docket No. R-00061931, Recommended Decision, July 24, 2007, page 63, and PA PUC v. Philadelphia Gas Works, Docket No. R-00061931 (Order Entered September 28, 2007), page 80.

> installing a system with enough throughput capacity to meet design peak demands in excess of annual demands.[19]

It should be noted that no party had put forward an A&E allocation methodology in that proceeding, and thus it was presumably not an option for the Commission. The Commission also explicitly rejected consideration of a mains cost allocation methodology that included a customer component of costs.

Finally, in the Company's most recent base rates proceeding, the Commission approved the Company's proposed A&E allocation method, that produced an allocation factor substantially similar to a peak demand allocator. In so doing, the Commission stressed the importance of peak demand as a cost causation factor for mains costs, citing to the gas distributions system being designed to meet peak demands, the need to assign considerable weight to the excess demand component of costs, the problematic double counting of average demand in the P&A allocator in both the peak component and the average demand component, and the P&A overstatement of the cost of service of more efficient gas users.[20] The Commission also declined to establish a standard methodology for mains cost allocation, concluding that cost causation may vary among the various NGDCs.[21]

Q. Has the Company adopted the same method for allocating mains costs in this proceeding as in the 2020 base rates case?

A. It has. Thus, for reasons of Commission precedent, I take no exception to that method. In so doing, I recognize that this method is probably the least favorable approach for small businesses, because it fails to recognize the economies of scale of serving larger customers (particularly in more geographically concentrated commercial areas) and because it does not

[19] Opinion and Order, Pennsylvania Public Utility Commission, Docket Nos. R-2020-3018835 et al., Order Entered February 19, 2021, at 217-218.

[20] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2020-3018929 et al., Order Entered June 17, 2021, at 228-231. The Commission did not directly address the issue of the treatment of interruptible service within the A&E allocator.

[21] *Id*.

provide the cost-avoidance benefits to weather-sensitive customers associated with the P&A approach.

Q. Please explain how the Company quantitatively develops the A&E allocation factor.

A. The A&E factor consists of three components: class average day demands, class excess day demands, and the weighting factor.

Average day demands are simply the total test year forecast volume divided by 365 days. The average demand allocator is arithmetically equivalent to an annual volume commodity allocator.

The excess demand allocator is based on peak demand *minus* average demand. Thus, the Company must develop a peak demand measure for each class. And it must do so for firm service and interruptible service customer classes. For firm service customers, the Company uses design day demands, which reflect the Company's estimate of the load level under design weather conditions. For interruptible service customers, the Company simply uses the average day demands as the peak, meaning that the excess demand factor in the A&E is zero. I discuss this issue at some length below.

The weighting factor determines how much the A&E allocator relies on average demand and how much relies on excess demand. Weighting the A&E with system coincident peak ("CP") load factor is the traditional approach. The Company uses an approach that includes all rate classes in the average day demand and only the firm peak design day demands, producing a 24.59 percent load factor for weighting.

Q. Regarding the issue of developing peak day demands, how does the Company develop its design day demands for its firm service customers for use in the A&E allocation factor?

A. To its credit, the Company has substantially modified its methodology for developing design day demands for the vast majority of its customers, namely those in Rates R, GC, MV-F and L. Because these customers are not daily metered, the Company must rely on monthly load patterns to divine a design day demand. As detailed in PECO Gas Statement No. 6, the Company uses a historical dataset consisting of monthly loads by class from 2017 through

2021. For each class, the Company determines an average per customer non-heating load based on average July/August loads, and it derives a per-customer usage per heating degree day based on the average heating loads in January and February. Design day demands are derived by multiplying the use per HDD by the design conditions (65 HDD), and adding that to the average daily non-heating load. Class load factors under design conditions are calculated for each class for the historical period, and then applied to FPFTY forecast customer count and loads.[22]

For its TS-F customers, it appears that the Company relies on contract demands, denoted transportation contract quantity ("TCQ").[23] Little information is offered as to how TCQs are developed, or whether they represent a reasonable proxy for the maximum load that the customer is expected to require under extreme weather conditions. However, it is not uncommon for NGDCs to use contract quantities as a measure of design day demand for daily metered customers for cost allocation purposes.

Q. Do you have any specific concerns regarding the Company's approach for developing design day demands for firm service customers?

A. I have two. First, I am concerned that the TS-F design day demand value of 69,000 mcf/day is not supported by the evidence. PECO indicates that the 69,000 value is derived in the PGC proceeding, and it has not advanced any supporting calculations. I have tried to evaluate whether that value is reasonable for cost allocation purposes. First, using the data in the Company's attachment to OSBA-I-2(a), I prepared a statistical analysis of the temperature sensitivity of TS-F customers using monthly data, and derived design day demand levels. Unfortunately, the Company did not fully segregate the data between TS-F and TS-I customers, so I can conclude only that the design day demand would be about 57,000 mcf/day plus some portion of the 15,000 mcf/day of joint TS-F/TS-I customers. Those values suggest that the Company's 69,000 value is not obviously unreasonable. However, in reviewing actual maximum daily usages for the TS-F customers, the Company's data in Attachment OSBA-I-2(b) indicate that maximum TS-F customer use is

[22] See Attachment OSBA-I-1(d).

[23] *Id.* The Company reports in this workpaper that the TS-F design day demands are based on TCQ.

in the 74,000 to 84,000 mcf/day range. I have not made any adjustments at this time, pending further justification from the Company for its 69,000 mcf/day value.[24]

Second, I have concerns regarding the Rate L allocation factor (recognizing of course that it applies only to five customers). Allocation of costs to Rate L is complicated by the fact that Rate L is a regular tariff distribution service, but PECO Gas also uses it as backup service for its TS-F and TS-I customers.[25] Thus, Rate L volumes can include both high load factor regular customers and extremely low load factor standby service. This resulted in nonsensical costs for Rate L in the Company's last base rates case. As I understand it, the Company attempted to address this issue in this proceeding by allocating costs to Rate L based only on the load patterns for the regular service customers. I agree that this would be a reasonable approach. However, the load factor for Rate L in the COSS is still surprisingly low at 28.2 percent. As I understand the Company's response to OSBA-I-2(f), it appears that the Company has included peak demands for Rate L only for regular customers but has continued to include volumes for the standby service. At this writing, I am unsure whether this is an inadvertent inconsistency, or whether the Company has a rationale for this approach.

Q. Have you made any adjustments to adjust for these concerns?

A. No. Pending the Company's rebuttal testimony, I will make any necessary modifications to the cost allocation analysis in my surrebuttal testimony.

Q. Turning to the issue of the Company's treatment of interruptible service for mains cost allocation. Please start with a discussion of the conceptual issues of allocating costs to interruptible service customers.

A. As its name implies, interruptible service customers take service from a natural gas utility that is subject to being interrupted, typically during periods of extreme weather and

[24] See RDK WP2.

[25] This, of course, makes no sense at all, and is a historical anachronism. Nevertheless, the Commission approved it in the last base rates case.

correspondingly high system demand. In exchange, the customer is offered a rate below that for firm service.

A gas utility may offer an interruptible service option for two reasons. First, being able to interrupt a utility gas sales customer (who buys gas from the utility) during extreme periods will allow the utility to reduce its need for design day capacity. This cost savings typically involves reducing the need for storage deliverability capacity and/or peak shaving capacity such as LNG. Thus, allocating gas supply costs to these customers generally reflects a reduced charge for those services.

Second, the utility may offer interruptible gas transportation service, which would allow the utility to avoid making reliability and expansion investments in its distribution system by being able to interrupt the customers when the distribution system is stressed. Cost allocation for these customers thus tends to reflect a reduction in costs that are related to peak system demand relative to firm service customers.

Unfortunately, these two rationales for offering interruptible service are sometimes muddled in utility cost allocation and rate design, particularly where legacy rates are in place associated with the historical practice of bundled gas supply and distribution service. For example, the interruptibility of utility gas supplies (often for economic reasons) may not provide any distribution benefits. For costing purposes, such a customer should be assigned reduced gas supply costs, but not a reduction to base distribution rate costs.

As a general rule, for utility costing purposes, the system benefits of interruptible sales service should reflect the savings in gas supply costs. In Pennsylvania, interruptible sales service options should be addressed in annual Section 1307(f) purchased gas cost ("PGC") proceedings. Distribution system benefits related to customer interruptibility are addressed in base rate proceedings.

Q. Please discuss the Company's treatment of interruptible service customers in developing its mains cost allocation method.

A. In this case, the Company proposes to treat customers in four rate classes as providing distribution benefits associated with their interruptibility, namely the MV-I, IS, TCS, and TS-I rate classes.

Because the MV-I, IS and TCS rate classes have rates set based on market conditions, and because these classes represent only a tiny fraction of PECO Gas costs, and because the Commission approved PECO Gas' retention of these rate classes, I take no position on the treatment of costs assigned to these classes. These allocated costs have little or no bearing on revenue allocation and rate design.

For the TS-I rate class rate class, the Company sets the "average" portion of the A&E allocator based on the class average day throughput excluding the customers for whom mains are directly assigned, and it sets the "excess" portion of the A&E allocator to zero. Because the Company's A&E method is heavily weighted to excess demand, the TS-I rate class in the PECO COSS represents 2.5 percent of mains A&E demand, while representing some 10.3 percent of annual throughput. This approach was, at least implicitly, approved by the Commission in its order in the 2020 base rates case.[26]

Q. Please explain how the Company allocates meters and services costs.

Regarding the allocation of meters and services costs, the Company uses a modified direct assignment approach, which is consistent with sound utility cost allocation practice.

To allocate meters costs, the Company has compiled the number of meters by size for each rate class and applied the unit cost for each sized meter (inclusive of installation cost), to develop an average cost per meter for each rate class.[27] This unit cost is then applied to the number of customers for the rate class in the COSS, to derive a meters allocation factor that applies to both meters plant (account 381) and meters installation plant (account 382).

[26] Opinion and Order, Pennsylvania Public Utility Commission, Docket No. R-2020-3018929 et al., Order Entered June 17, 2021, at 228-231. The Commission did not directly address the issue of the treatment of interruptible service within the A&E allocator.

[27] See Attachment OSBA-I-1(e) and OSBA-I-1(d)

In reviewing this information, I note in particular that the derivation of the meters cost allocator reinforces the heterogeneous nature of Rate GC class, in that the workpapers show that the class is served by 38 different meter sizes. Also, it should be recognized that over 75 percent of the Rate GC meters are the same size as the most common Residential meters (sizes 11 to 20 and 33), with an average cost of $384, compared to the class average cost of $1,352 and individual meters costs up to $37,816.[28] As discussed further below, it is not reasonable to set the customer charge for the GC class based on an average meters cost of $1,352, when the vast majority of customers subject to that charge cause a cost of $384.

Turning to the allocation of service line costs, recognize first that this is an enormous cost component. Where mains costs attract all of the methodological attention in a COSS, services costs represent nearly 32 percent of the Company's net plant (with mains at 56 percent). The Company's allocation method for services is addressed in some detail in PECO Statement No. 6. The Company's records do not track actual service costs by rate class, so PECO uses the actual service costs incurred during the past five years to allocate the cost for a single service line by rate category. The Company then multiplies the cost per line by the number of customers in the class to develop the allocation factor. The Company ignores the fact that many customers are served by multiple service lines in developing this allocator, due to a lack of data.[29]

In this proceeding, and to its credit, the Company has made an effort to improve the allocation of services costs, and it has modified the data set from which it draws cost data for non-residential services. However, even with expansion, the services cost dataset is not sufficiently robust for the Company to differentiate costs by non-residential service class, so it simply lumps all the non-residential customers into a single unit cost category. In effect, the service line cost for the smallest Rate GC customer is assumed to be the same as that for the largest Rate GC customer, and the same as that for each TS-F and TS-I customer. The Company's method indicates that the average cost for a non-residential service is 2.9 times

[28] See Attachment OSBA-I-2(e).

[29] See OSBA-I-2(j). In the last base rates proceeding, the Company's data for multiple service lines indicated that this method unfairly treats Rate GC customers, where multiple customers being served by one service line appeared to be more prevalent.

that for a residential service. At this writing, it is unclear why PECO Gas limits its analysis to the most recent five years of cost information. If the sample is expanded to ten years, PECO Gas reports that the non-residential to residential unit cost ratio is 2.6 rather than 2.9.

Pending clarification from the Company as to why the dataset is limited, I have not made any adjustments to the Company's services cost allocation method, although it appears to assign excessive costs to small business customers. Moreover, I encourage the Company to continue with its efforts to refine and enhance the services cost allocation method, given the large magnitude of that cost.

In addition, as was the case with meters, it must be recognized that the many small customers within the Rate GC class likely have services costs that are similar in magnitude to that for residential customers. Thus, when the customer charge is set for small Rate GC customers, it must recognize that the services costs for small GC customers are much more likely to be the $6,000 cost for a residential service than the $17,000 average cost for all non-residential customers.

Q. Please address the revenue issues in the Company's filed COSS.

A. Two issues arose in my review of the Company's proof of revenues analysis, which affect the revenues reported in the COSS. The Company has acknowledged both errors, and it indicates that it will correct these items in rebuttal testimony.

First, the DSIC revenues in the proof of revenues were incorrectly allocated amongst the various rate classes.[30] This error affects only revenues at current rates, because the DSIC revenues are zeroed out and rolled into the regular proposed tariff charges for the FPFTY.

Second, the Company acknowledges that it improperly included certain revenues associated with PGC services in its current rates for the TS-F and TS-I rate classes, and not in its

[30] OSBA-I-4(i).

proposed revenues.[31] In effect, current rate revenues for these classes is overstated. It is not clear if this error will affect the Company's claimed rate increase.

The Company indicates that it will correct these errors in its rebuttal testimony.

Q. Have you developed an alternative version of the Company's COSS to reflect the admitted errors related to revenues?

A. No. After the Company corrects the errors related to revenues in its rebuttal testimony, I will prepare an alternative COSS for surrebuttal should that prove necessary for revenue allocation and rate design recommendations.

4. <u>Revenue Allocation</u>

Q. What is revenue allocation?

A. Revenue allocation is the assignment of the dollar net increase or decrease to each of the Company's rate classes in a base rates proceeding. In contrast, *rate design* determines how the allocated revenue is recovered from individual ratepayers within each class. From a cost recovery standpoint, revenue allocation addresses *inter-class* cross-subsidization issues, while rate design addresses *intra-class* cross-subsidization issues.

Q. What are the primary economic and regulatory criteria for revenue allocation?

A. In general, allocated cost is the primary criterion used by regulators in the revenue allocation process. Most utilities and regulators adopt a policy in a base rates proceeding of attempting to move revenues more into line with allocated costs by varying the magnitude of the rate increases for the individual classes. However, regulators also subject the rate increases to other non-cost criteria of ratemaking. Of the traditional rate design criteria, the most common non-cost considerations in the revenue allocation process are:

- the *gradualism* principle (or avoidance of "rate shock"), in which large rate increases for individual customers or classes of customers are avoided; and

[31] OSBA-I-4(k).

- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively elastic demand.[32]

Using these criteria, the utility will develop a proposal for assigning the increase in the revenue requirement among the classes that reflects both cost and non-cost considerations. With this proposal, the COSS can be simulated at both present and proposed rates to evaluate the magnitude of "progress" that has been made toward the policy of achieving cost-based rates.

Q. Are there customers or customer classes for which revenue allocation does not reflect allocated cost?

A. Yes. Where rates are set at alternative fuel market prices, or where discounted rates are set based on the need to meet a competitive threat, the results of the cost allocation study have little relevance to revenue allocation. In general, because these rates are not set based on allocated cost, the revenues produced by these rate classes at current rates already reflect the market and competitive circumstances, and thus the revenues at proposed rates are either equal to or little different from the revenues at current rates.

For this proceeding, this implies that no increases should be assigned to the MV-I, IS and TCS rate classes because rates are set based on market conditions. Thus, for three of the rate classes in the Company's COSS, the cost allocation study provides little useful information for ratesetting. In addition, the rates paid by the Rate NGS customers within the TS-F and TS-I classes are not subjected to the rate increase. Thus, the revenue reported for those two rate classes reflects the competitive discounts for the Rate NGS customers.

Q. Are there revenue allocation implications for these market-based rate classes?

A. There are two distinct issues to be addressed. The first is whether the competitive rates reasonably reflect the market/competitive conditions that they are designed to address.

---

[32] See, for example, Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, pages 383 to 387. Note that the criteria in this text apply to the overall development of a utility rate structure. The criteria that I discuss in this testimony are those that apply to the revenue allocation portion of the process, which is only one aspect of the overall development of utility rates.

The second is whether the revenue shortfalls from the competitive discounts are assigned only to the rate classes in which those customers take service, or whether the burden is shared more broadly among all rate classes.

Q. Let's turn to the issue of the reasonableness of revenues first. Please provide your evaluation of the Company's justification for the market-based revenues.

A. For the MV-I, IS and TCS rate classes, my testimony in the Company's last base rates case indicated that the rates did not appear to be consistent with market prices for the competitive fuels upon which they were purportedly based. Moreover, I concluded that these rates were anachronistic and potentially anti-competitive, and that they were used by only a small number of customers. I proposed that these rate classes be phased out or eliminated. Both the Company and the Commission disagreed, and the rates were retained, although customer participation in these rates appears to be declining. I take no position on these tariffs regarding the reasonableness of the assumed revenues.

I observe, however, that the distribution rate revenues claimed by the Company for the FPFTY from these classes are far lower than those recently posted by the Company effective July 1, 2022.[33] The Company should provide an explanation for the relatively low rates used in the forecast, or it should update its forecast to reflect more recent expectations for alternative fuel prices.

For the Rate NGS customers, the Company indicates that it currently has six customers taking Rate NGS service. For four of those customers, PECO Gas presents an updated review of its justification for the rate discounts. For two of the Rate NGS customers, the Company concludes that it has already met its burden to justify the rate discounts for other Rate NGS customers. Most of the dollar value associated with the Rate NGS rate discounts fall into the latter category. The former customers are addressed confidentially below, using the number scheme from Statement No. 7.

[33] For example, PECO's July 1, 2022 TCS distribution rate will be $4.68 per mcf, compared to $2.78 in the proof of revenues. If the current value is more accurate, the current rate revenues are understated by nearly $300,000.

1 ***** BEGIN CONFIDENTIAL *****

2 [redacted]

3 [redacted]

4 [redacted]

5 [redacted]

6 [redacted]

7 [redacted]

8 [redacted]

9 [redacted]

10 [redacted]

11 [redacted]

12 [redacted]

13 [redacted]

14 [redacted]

15 [redacted]

16 [redacted]

17 [redacted]

18 [redacted]

19 [redacted]

20 [redacted]

21 [redacted]

22 [redacted]

23 [redacted]

24 [redacted]

25 [redacted]

[34] CONFIDENTIAL OSBA-I-7, CONFIDENTIAL Attachment OSBA-I-6(a).

[35] OSBA-I-8, CONFIDENTIAL Attachment I-8(a), CONFIDENTIAL Attachment OSBA-I-6(a).

[36] See RDK WP1 "Misc" worksheet for a capital recovery factor calculator.

[redacted]

[redacted]

******* END CONFIDENTIAL *******

Q. How does the Company assign the responsibility for recovering the shortfall from customers on market-based rates among the various rate classes?

A. For the MV-I, IS and TCS rate classes, the Company's COSS shows surplus revenues above allocated costs. This surplus is implicitly reflected in a reduced allocation of the revenue increase among the regular rate customers. Because there is so little volume and revenue associated with these classes, the impact of this surplus is *de minimis*.

For the NGS customers, the Company includes the Rate NGS revenue shortfall in the TS-F and TS-I rate classes. In effect, the Company proposes that the regular rate TS-F and TS-I customers bear the burden of the shortfall from the Rate NGS customers.

[37] CONFIDENTIAL OSBA-I-9, CONFIDENTIAL Attachment OSBA-I-6(a).

[38] OSBA-I-10, CONFIDENTIAL Attachment OSBA-I-6(a).

Q. Is the Company's proposed treatment of the Rate NGS shortfall reasonable?

A. As a general rule, I do not believe that it is reasonable for flex rate customer discounts to be borne by the customer class in which those customers would otherwise take service. Offering flex rate discounts retains revenue that provides an offset to utility costs, to the benefit of all rate classes. As such, I generally advocate that the shortfall be reallocated among all rate classes, to more reasonably share this burden.

However, in this case, the shortfall from Rate NGS customers is complicated by the treatment of mains costs for a subset of the Rate NGS customers. In particular, it is my understanding that the Company directly assigns some mains and other distribution plant to the TS-F and TS-I rate classes for some Rate NGS customers. Thus, the per-mcf allocated cost to serve for the Rate NGS customers as a group is presumably substantially lower than that for the other TS-F and TS-I rate classes. Thus, while the regular TS-F and TS-I customers bear the responsibility for the Rate NGS discounts in the Company's approach, they also benefit from the reduced costs associated with some of those customers.

Unfortunately, it is not possible for me to determine the relative magnitude of these offsetting impacts on the TS-F and TS-I customers. Thus, for the purposes of this testimony, I have not made any effort to reallocate any net revenue shortfall (if one exists) from the Rate NGS customers in the TS-F and TS-I classes to the other rate classes. To mitigate this problem in the future, the Company should consider establishing a separate cost allocation class for the Rate NGS customers, which would allow parties to see the magnitude of any rate shortfall from these customers, and to address it directly in revenue allocation analyses. Columbia Gas has adopted this approach for its flex rate customers.

Q. What does the Company propose for revenue allocation in this case?

A. The Company's revenue allocation approach is presented in Statement No. 7. The Company generally indicates a desire to move rates more into line with allocated costs, while limiting the rate increase for any particular class to no more than 2.0 times the system average increase. Based on my review of the numbers, I interpret the Company's revenue allocation approach to be the following:

- Rates MV-I, IS, and TCS: The rates for these classes are primarily market based, and thus revenue allocation is essentially zero. The Company's proof of revenues does include some shifting of revenues within these classes between the customer charge, the volumetric charge and the DSIC.[39]

- Rates L and TS-I: These classes are currently producing revenues that are well in excess of fully allocated cost. Revenue allocation is therefore set to zero. This allows revenues to move more into line with allocated costs, but these classes continue to provide excess revenues.

- Rates GC and MV-F: These classes are currently providing revenues that modestly exceed costs at current rates. The Company proposes to assign percentage revenue increases to these classes that are below system average, which will move revenues and costs fully into line.

- Rates GR and TS-F: These classes are currently providing revenues that fall below moderately fully allocated cost. The Company proposes to assign revenue increases to these classes that are modestly higher than the system average increase, designed to move revenues fully into line with allocated costs.

The Company evaluates its revenue allocation proposal using an indexed rate of return methodology. Because the indexed rate of return methodology can provide misleading signals for revenue allocation, I evaluate progress toward cost-based rates using a revenue-cost ratio methodology.[40] This method is simply the ratio of class revenues to the fully allocated costs for each class (inclusive of return and income taxes).[41] My calculations are shown in RDK WP1, and they demonstrate that the Company's proposal results in material progress toward cost-based rates for all rate classes. In this case, because the Company

[39] It is not clear why rates shift within these classes, given that the volumetric charges are market-based. However, the net effect is tiny.

[40] See Appendix A for an explanation.

[41] At current rates, the R/C ratio is calculated as if an across-the-board increase is assigned to all rate classes. See Appendix A.

proposes to move most of the major rate classes fully into line with allocated cost, the indexed rate of return method does not produce unreasonable results.

Q. Is this approach reasonable?

A. The Company's approach is fully consistent with its filed COSS. The Company's proposal is reasonably aggressive in moving revenues into line with allocated costs for most rate classes, while adopting the reasonable position that no class should be assigned a rate decrease (in a proceeding when other rate classes face increases in excess of 20 percent). The Company establishes an upper limit for class rate increases of 2.0 times system average, but no class faces an increase near that magnitude.

However, the Company's COSS has a number of admitted inaccuracies, and there are cost allocation issues that have not been fully explained. Thus, I expect the Company will provide a revised COSS in its rebuttal testimony, and a revised revenue allocation proposal if it finds that to be necessary. I will respond to these corrections and updates as necessary in surrebuttal testimony.

5. <u>Rate Design for Non-Residential Customers</u>

Q. What issues do you address regarding rate design for non-residential customers?

A. I address the following:

- Rate GC tariff design, notably the proposed increase in the customer charge and the steeply declining volumetric block rates, both of which serve to lower average rates for large customers;
- Rate differentials in the TS-F and TS-I tariffs above and below 18 mmcf per year.

5.1 Rate Design for Rate GC

Q. Please describe the Company's proposal for the Rate GC tariff.

A. Rate GC currently consists of a customer charge, a two-step declining block commodity charge, supplemented by the DSIC and TCJA charges that apply to all customers, and the MFC and GPC charges for recovery of additional base rates costs. As explained earlier, the TCJA and DSIC get zeroed out with new base rates (although the DSIC will go back into effect when investment minima are reached, generally near the end of the future test year).

Table RDK-1 below shows the current and proposed changes in tariff charges, as well as the bill implications for the average customer.

Table RDK-1 PECO Gas Rate Design Proposal: Rate GC			
	Current Rate	**Proposed Rate**	**Rate Impact Percent**
Customer Charge ($/mo.)	$28.55	$38.82	36.0%
First 200 mcf ($/mcf)	$3.9548	$4.4439	12.4%
Over 200 mcf ($/mcf)	$2.9798	$3.3483	12.4%
DSIC (%)*	2.05%	0.0%	-100%
Annualization (%)	0.7317%	0.7317%	13.8%
Average Excl PGC/MFC/GPC	**$4.469**	**$5.085**	**13.8%**
* Not corrected for PECO Gas misallocation. Excludes impacts of changes to GPC and MFC. Sources: RDK WP1, "RevPrf" tab.			

In short, the Company proposes a disproportionate increase in the customer charge, with no relative change in the current declining block commodity charges. The first block charge remains at 33 percent above the second block charge.

Q. Before getting into the details the GC tariff charges, did you review the Company's proposed volumetric billing determinants for the GC class for load above and below the 200 mcf breakpoint?

A. I did. In this proceeding, the Company's proof of revenue shows a material shift of volume to the lower priced tail block compared to the last base rates case. This of course reduces the average current rate revenue per mcf for the GC class, and it increases the required rate increase. The Company explains this change by indicating that it used a five-year average in this case rather than a single historical year. However, the data that the Company provided in Attachment OSBA-I-4(b) for historical averages does not justify the volumetric shift, and the data provided in Attachment OSBA-I-4(c) does not appear to be consistent with the data in Attachment OSBA-I-4(b). The Company is invited to explain the apparent discrepancy. I will address this issue as necessary in surrebuttal.

Q. Turning to the customer charge for Rate GC, Is the proposed increase to that charge reasonable?

A. No. Setting the customer charge for utility general service rate classes is difficult due to the heterogeneous nature of the customers in the class. Rate GC customers come in a wide range of sizes and load patterns, particularly for PECO Gas. For example, in the Company's GC class, approximately 8 percent or some 3,700 customers have annual consumption that is below that for the average residential customers. Thus, as I explained earlier, the smaller customers in the class have less expensive meters and services than the average customer in the class. If the customer charge is set at the average customer-related cost for all customers in the class, smaller customers will necessarily be subsidizing larger customers.

Thus, to avoid cross-subsidization, I recommend that the customer charge for Rate GC be set no higher than the full customer-related cost for small customers in the class. While the COSS cannot be used to measure the customer cost for small customers, the residential class customer cost serves as a reasonable proxy, because the customer-related costs for residential and small GC customers are similar. The residential class customer cost is approximately $28 per customer per month.[42] Therefore, I recommend that the current customer charge of $28.55 remain in effect.

In the alternative, PECO Gas could take the approach used by other Pennsylvania NGDCs, namely that of differentiating the customer charge within the class between smaller and larger customers. As I noted earlier, Rate GC is a highly diverse class, with a wide range in customer sizes from smallest to largest. If a differentiated customer charge approach were adopted, the current $28.55 would continue to apply to smaller customers in the class, while a higher charge would apply to customers with annual volumes above some reasonable level. At this writing, I have not developed any specific proposal in this respect, but I am advised

[42] See RDK WP1 "Return & Taxes" worksheet. In making this calculation, I include all customer-related costs in the COSS. I recognize that certain indirect customer-related costs are sometimes excluded from the customer chare for residential customers for policy reasons. The $28 value also includes costs related to residential-only customer assistance programs, plus uncollectibles costs that should generally not be classified as customer related. Without those costs, the residential customer cost is under $27 per month.

by counsel that OSBA is willing to work with the Company to develop such a proposal as part of any potential settlement negotiations in this case.

Q. Has the Company offered any cost support for its proposal to retain the declining block volumetric charge?

A. No. By way of background, declining block volumetric charges result in lower average unit rates for larger customers within the class. This tariff design has traditionally been used by utilities for three alternative purposes. First, it is often argued that because the customer charge does not fully recover customer costs, it is appropriate to include that recovery in the first block volumetric charge. Second, it is argued that because larger customers tend to have higher load factors, the volumetric unit distribution cost is lower for larger high load factor customers than for smaller low load factor customers, because distribution costs are substantially allocated based on peak demand. Third, the declining block tariff was designed such that the tail block reflected system marginal costs (particularly in the electric industry), recognizing that the incremental cost of service was often than the average cost.

The Company offers no evidence in support for any of these propositions.

First, as I discussed above, the current customer charge fully recovers the customer-related costs for smaller customers, and thus there is no need to provide a volumetric rate discount to larger customers.

Second, the Company has not prepared any analysis that larger customers in the Rate GC class have a higher load factor than smaller customers. Based on the information provided by the Company, I prepared an analysis comparing the estimated design day load factor for each Rate GC customer with the average customer size. If larger customers actually had lower load factors, there would be clear statistical evidence of a positive correlation between load factor and customer size. That analysis shows that there is a positive but weak correlation between customer size and load factor, but it falls well short of that necessary to justify the Company's wide rate differential.[43]

[43] See RDK WP3, resubmitted from the Company's last base rates case.

Finally, the Company offers no evidence that the incremental cost of service is lower than the average cost. In fact, in a period when the Company is replacing low-cost depreciated assets with high-cost plant, the incremental (or decremental) cost related to load is likely to be much higher than the average embedded cost. Moreover, even if incremental cost is below average cost, it is inequitable to assign those economies of scale disproportionately to large customers. Each unit of design day load contributes equally to cost causation.

Q. What do you propose?

A. I propose that the Company reduce the volumetric charge differential by applying a larger percentage rate increase to the tail block charge. My overall proposal for an alternative Rate GC tariff design is presented in RDK WP1 ("RevPrf RDK" worksheet) and summarized in Table RDK-2 below. This proposal will reduce the ratio of first block to second block charges from 1.33 to 1.25. Note that the values in Table RDK-2 are based on the Company's proposed revenue allocation without correcting for the revenue errors. I will update this recommendation as necessary in surrebuttal testimony.

Table RDK-2
RDK Rate GC Rate Design Proposal

	Current Rate	Proposed Rate	Percent
Customer Charge ($/mo.)	$28.55	$28.55	0.0%
First 200 mcf ($/mcf)	$3.9548	$4.6469	17.5%
Over 200 mcf ($/mcf)	$2.9798	$3.6997	24.2%
DSIC (%)*	2.05%	0.0%	-100%
Annualization (%)	0.7317%	0.0%	-100%
Average Excl PGC/MFC/GPC	**$4.469**		

* Not corrected for PECO Gas misallocation.
Excludes impacts of changes to GPC and MFC.
Sources: RDK WP1, "RevPrf RDK" worksheet.

5.2 Rate Differentials for Rate TS-F

Q. Please review the issues involving rate differentials for the Company's transportation service classes.

A. Both Rate TS-F and Rate TS-I have separate base rate charges for customers whose annual volume is below 18 mmcf and customers whose annual volume is at or above 18 mmcf. For

both classes, the larger customers represent a significant majority of both throughput and base rate revenues, and the rates for the smaller customers are materially higher than those for the larger customers. Despite the fact that the Company has completely separate tariff charges for the smaller customers and the larger customers within these two classes, it does not conduct any cost analysis of the difference.

Q. What is the Company's proposal for rate design for the TS-F class?

A. The Company's proposed regular rate tariff for Rate TS-F includes a customer charge and a volumetric charge, both differentiated between customers below 18 mmcf per year and above 18 mmcf per year. The Company proposes to assign a disproportionate increase to the customer charges than to the commodity charges, but the same percentage increases are applied to larger and smaller customers. The proposed charges are shown in Table RDK-3 below:

Table RDK-3
PECO Gas Rate TS-F Rate Design Proposal

	Under 18 mmcf	Over 18 mmcf	Differential
Current Rates			
Customer Charge ($/mo.)	$221.07	$184.00	-16.8%
Volumetric Charge ($/mcf)	$1.9416	$0.9267	109.5%
Average Charge* ($/mcf)	$2.27	$0.98	130.2%
Proposed Rates			
Customer Charge ($/mo.)	$278.66	$334.80	-16.8%
Volumetric Charge ($/mcf)	$2.5356	$1.2102	109.5%
Average Charge* ($/mcf)	$2.96	$1.27	133.3%
Percent Increase			
Customer Charge ($/mo.)	51.4%	51.4%	--
Volumetric Charge ($/mcf)	30.6%	30.6%	--
Average Charge* ($/mcf)	30.5%	28.8%	--

* Current rate tariff charges include the effect of the DSIC. Averages exclude negotiated rate customers and PGC-related charges.
Sources: RDK WP1, "RevPrf" tab.

Table RDK-3 shows that the Company's tariff implies that the cost to serve the smaller customers is more than double the cost to serve larger customers on a per-mcf basis.

There are two reasons why higher volumetric rates may reasonably apply to smaller customers. First, the customer charge could be under-recovering cost, and thus a higher volumetric rate should apply to smaller customer loads. For Rate TS-F, any such affect would be minimal. At most, the customer charge for the smaller customers is about $85 per month short of the average cost for the class, which would justify less than 10 cents per mcf in the rate differential.[44] Moreover, smaller customers in Rate TS-F presumably have lower meters and services costs than the larger customers, and thus a lower customer charge is cost-justified.

Second the tariff charge for the larger customers could reflect higher load factors for those customers, since the demand-related costs for higher load factor customers are lower on a per-mcf basis. To evaluate whether this is the case, I conducted two different evaluations in the last base rates case. First, using the monthly load data provided by the Company, I estimated design day demands and associated load factors for both sub-groups of TS-F customers. This analysis did indicate that the load factors for larger customers were higher than for the smaller customers. However, the ratio of load factors was 1.43:1, which does not justify the 2.1:1 ratio between volumetric charges in the current and proposed tariff structure. Second, I reviewed the load factors based on customer contract demand (Transportation Contract Quantity "TCQ") for each TS-F customer. Overall, that analysis showed some statistically weak correlation between size of customer and load factor. This analysis similarly showed a higher load factor for customers above 18 mmcf, but again at a ratio (1.25 to 1.53) that falls well short of the Company's proposed 2.1:1 ratio.[45]

---

[44] The fully loaded customer cost for all customers in Rate TS-F is $337, but the cost for the smaller customers in the class is almost certainly much lower, since most of the customer plant is related to meters and there is a wide range of meter costs in the TS-F class. However, even assuming small customer's cost $337 per month, the maximum shortfall in the customer charge is $337-$229 = $108. That $108 per month applied to the Company's customer count and under 18 mmcf volumes implies an upper bound differential of 8.8 cents per mcf. RDK WP1 "RevPrf" worksheet.

[45] RDK WP4 from Docket No. 2020-, included herein as RDK WP4.

I therefore conclude that the TS-F volumetric charge differential is excessive and should be reduced in this proceeding. In addition, because the Company has no customer cost analysis to justify the very large increase for the smaller customers within the TS-F class, I propose to limit the customer charge increase to the class average.

Based on the Company's revenue allocation proposal, my rate design proposal for the TS-F class is shown in Table RDK-4 below. As shown, even with these differentiated increases, the ratio of the volumetric charges is 1.88:1, and the average rate for the larger customers remains below half that for the smaller customers. In addition, I note that this proposal does not violate the Company's proposed rate gradualism constraint, as the average increase for TS-F customers above 18 mmcf per year is about 1.75 times the system average increase.

Table RDK-4
RDK Alternative Rate TS-F Rate Design Proposal

	Under 18 mmcf	Over 18 mmcf	Differential
Current Rates			
Customer Charge ($/mo.)	$221.07	$184.00	-32.1%
Volumetric Charge ($/mcf)	$1.9416	$0.9267	109.5%
Average Charge* ($/mcf)	$2.27	$0.98	130.2%
Proposed Rates			
Customer Charge ($/mo.)	$227.26	$334.80	-16.8%
Volumetric Charge ($/mcf)	$2.2832	$1.2102	87.7%
Average Charge* ($/mcf)	$2.73	$1.33	105.5%
Percent Increase			
Customer Charge ($/mo.)	51.4%	51.4%	--
Volumetric Charge ($/mcf)	30.6%	30.6%	--
Average Charge* ($/mcf)	30.5%	28.8%	--

* Current rate tariff charges include the effect of the DSIC. Averages exclude negotiated rate customers and PGC-related charges.
Sources: RDK WP1, "RevPrf RDK" tab.

Q. Please address the tariff charge differentials within Rate TS-I for customers above and below 18 mmcf per year.

A. The Company's proposal for Rate TS-I is similar to that for Rate TS-F, in that it has bifurcated customer and volumetric charges for customers above and below 18 mmcf per year, and it has not made any effort to evaluate the reasonableness of the differential.

Unlike Rate TS-F, however, there is no load factor justification for a volumetric rate differential. Under the Company's cost allocation philosophy, demand-related costs are assigned to this class almost entirely on the basis of average annual volumes. Thus, there is no difference in allocated distribution plant costs between small and large customers.

The Company proposes a zero increase for the Rate TS-I class. However, in order to roll in the DSIC, and to roll in the (erroneously included) PGC-relate charges, the Company proposes to assign increases to the basic TS-I charges. The key components of the Company's proposed rate design for TS-I customers are shown in Table RDK-5 below.

Table RDK-5
PECO Gas Rate TS-I Rate Design Proposal

	Under 18 mmcf	Over 18 mmcf	Differential
Current Rates			
Customer Charge ($/mo.)	$233.00	$277.21	-15.9%
Volumetric Charge ($/mcf)	$1.5931	$0.8484	87.8%
Average Charge* ($/mcf)	$1.98	$0.90	130.2%
Proposed Rates			
Customer Charge ($/mo.)	$318.86	$379.36	-16.8%
Volumetric Charge ($/mcf)	$1.6968	$0.9036	109.5%
Average Charge* ($/mcf)	$2.23	$0.97	120.5%
Percent Increase			
Customer Charge ($/mo.)	36.8%	36.8%	--
Volumetric Charge ($/mcf)	6.5%	6.5%	--
Average Charge* ($/mcf)	12.5%	8.2%	--

* Current rate tariff charges include the effect of the DSIC. Averages excludes negotiated rate customers; excludes PGC and backup related charges.
Sources: RDK WP1, "RevPrf" tab.

Q. Please provide your proposed rate design for Rate TS-I.

A. My proposed rate design for Rate TS-I is summarized in Table RDK-6 below, and in detail in RDK WP1 ("RevPrf RDK" worksheet). As shown, I propose no increase to the customer

charge for the smaller customers within the TS-I class because the current customer charge is already higher than my proposed customer charge for smaller Rate TS-F customers, and there is no cost evidence that smaller TS-I customers have a higher customer cost than smaller TS-F customers. To narrow the unjustified volumetric charge differential, I propose to assign zero increase to the current TS-I volumetric charge for smaller customers, and apply an increase to the volumetric charge for larger customers. As shown, this approach results in a zero increase for smaller customers within the class, and a moderate increase for larger customers. It serves to reduce the volumetric charge ratio from 1.88 to 1.71, and it reduces the average rate premium for smaller customers from 130 percent to 98 percent. Of course, this proposal may need to be modified when the Company corrects its treatment of PGC-related revenues for the Rate TS-I class, if that change results in a change in revenue allocation.

Table RDK-6
RDK Alternative Rate TS-I Rate Design Proposal

	Under 18 mmcf	Over 18 mmcf	Differential
Current Rates			
Customer Charge ($/mo.)	$233.00	$277.21	-15.9%
Volumetric Charge ($/mcf)	$1.5931	$0.8484	87.8%
Average Charge* ($/mcf)	$1.98	$0.90	130.2%
Proposed Rates			
Customer Charge ($/mo.)	$233.00	$379.36	-38.6%
Volumetric Charge ($/mcf)	$1.5931	$0.9344	70.5%
Average Charge* ($/mcf)	$1.98	$1.00	97.6%
Percent Increase			
Customer Charge ($/mo.)	0.0%	36.8%	--
Volumetric Charge ($/mcf)	0.0%	6.5%	--
Average Charge* ($/mcf)	0.0%	8.2%	--

* Current rate tariff charges include the effect of the DSIC. Averages excludes negotiated rate customers; excludes PGC and backup related charges.
Sources: RDK WP1, "RevPrf" tab.

Q. Does this conclude your direct testimony?

A. Yes, it does.

APPENDIX A

MEASURES OF PROGRESS TOWARD COST BASED RATES

PENNSYLVANIA UTILITY COST AND REVENUE ALLOCATION

Introduction

The Pennsylvania Commonwealth Court held that cost of service is "the polestar" criterion for assigning a utility rate increase among the various rate classes.[46] Parties to Pennsylvania base rates proceedings generally agree that this criterion implies that the revenues for each class at the rates approved by the Commission should be closer to allocated costs than the rates in place when the rate case is filed. Thus, parties to the proceeding will typically compare some metric for cost recovery under "proposed rates" with that same metric for cost recovery under "current rates." This comparison can show (a) *whether* the proposed rates result in class revenues that are closer to allocated costs, and (b) *how much* progress the proposed rates make toward moving class revenues toward allocated costs.

While different metrics are used for this analysis, the most common metric in Pennsylvania is the "indexed rate of return" metric (also called the "relative rate of return" or "unitized rate of return" metric). This appendix demonstrates why the indexed rate of return is not a reliable metric for identifying whether proposed rates are closer to allocate costs than current rates, and that even where the indexed rate of return correctly implies that there is progress toward cost-based rates, it is not a reliable indicator of the amount of progress that is achieved.[47] This appendix also compares the indexed rate of return to three other metrics for evaluating progress toward cost-based rates, namely the dollar subsidy, the rate of return differential, and revenue-cost ratio metrics.

---

[46] Lloyd v. Pennsylvania Public Utility Commission, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

[47] This problem with the indexed rate of return metric was identified in OSBA-sponsored testimony at least as early as 1994. This critique has been presented in expert testimony many times since. No credible rebuttal to these basic conclusions has been submitted, but the widespread use of this metric continues.

The Structure of the Cost Allocation Study

The indexed rate of return metric is derived from the method that is most often used for utility cost allocation in Pennsylvania. When a utility or regulator develops a revenue requirement for a test year, it simply sums all of the individual cost items for that year, including operating and maintenance ("O&M"), administrative and general ("A&G"), depreciation, taxes other than income, income taxes and allowed return on rate base. Thus, the objective of a cost allocation study should be to simply allocate each of these cost elements to the various rate classes. Because the allowed return and associated income tax are derived from rate base, the cost allocation study allocates all net plant and other rate base items to the various rate classes, and the return and income taxes can then be allocated in proportion to rate base.

Cost allocation studies in Pennsylvania, however, are most often conducted on a class rate of return basis. That is, the cost allocation study calculates a class rate of return by taking revenues, deducting the allocated O&M, A&G, depreciation and taxes other than income, to produce a pre-tax class net income. Income taxes are then most often allocated based on the calculated pre-tax class income, and a net income by class value is derived by difference. The allocated pre-tax and net income figures are thus not a cost of capital, but represent the implied return provided by each class under the revenues (current or proposed) used in the cost allocation study. These net income values are then divided by the allocated rate base, to produce percentage class rates of return.[48] Thus, with this approach to cost allocation, there is a desire by utilities and regulators to develop a metric for evaluating progress toward cost-based rates that is based on the class rates of return produced by the cost allocation study.

Defining Progress Toward Cost-Based Rates

It is not necessarily obvious what it means to "move rates more into line with allocated cost" between current and proposed rates. At the simplest level, one could argue that if the current rate revenues for a particular class are below the allocated cost for that class at the full proposed

[48] Some Pennsylvania utilities also calculate cost of service using a "levelized rate of return" method, in which return and income tax costs are allocated such that each class produces the system average rate of return. This approach is arithmetically equivalent to allocating return and income tax costs in proportion to rate base, as described above.

revenue requirement, any increase in rates will move that class's revenues closer to allocated cost. However, the objective of this exercise is to measure the progress toward cost-based rates for each rate class compared to that for all of the other classes. Thus, a revenue allocation proposal must be evaluated for its impact on all of the rate classes.

Also at the simplest level, of course, a proposed revenue allocation will by definition move rates more into line with allocated cost if each class's revenues are moved exactly to the full proposed allocated cost of service. Or, equivalently, rates are exactly cost-based when each class's revenues are set such that the class produces the system average rate of return. Therefore, there is no question that moving a class exactly to an indexed rate of return of unity (1.0) is necessarily consistent with making rates more cost-based.

In many base rate proceedings, however, moving rates fully into line with allocated costs cannot be achieved due to consideration of other rate design factors, most notably "rate gradualism," which serves to limit the increase for any particular class of customers in any rate proceeding, and has the aim of gradually moving rates into line with allocated cost.

Thus, in terms of determining whether a particular rate proposal moves rates into line with allocated cost, this appendix takes the position that there is progress toward cost-based rates if the proposed relative rate increases across the various classes, when followed for a number of base rates proceedings (in which there is no change in the relative cost structure), will eventually result in cost-based rates. Thus, for any particular metric, it is important to consider not only the difference between the metric and current rates and proposed rates in one base rates case, but also what that metric will imply going into the next base rates case.

As shown further in the numerical example below, this standard for defining progress implies that for classes with revenues below allocated cost at current rates (or, equivalently, with a class rate of return below system average), progress can only be achieved by assigning that class a rate increase above the system average increase. This, of course, is just plain common sense. If a class is under-recovering costs, it should be assigned an above average increase. As shown below, however, the indexed rate of return metric fails at common sense.

The Numerical Example

This appendix takes the approach of defining a specific numerical example, and showing the implications of various different metrics on different rate increase scenario. The calculations associated with this example are also provided in MS Excel electronic format (RDK WP5), and parties are able to simulate alternative examples to evaluate the rigor of this analysis.

The example attached to this appendix shows the arithmetic impacts of a single two-class utility example under four different rate increase proposals. Each page shows the implications of a different revenue-cost metric, namely the indexed rate of return, dollar subsidy, differential rate of return, the revenue-cost ratio and the normalized revenue-cost ratio.

The example involves two rate classes, A and B, in which each generates the same revenue at current rates, but in which Class A has a moderately higher cost to serve. The four rate increase scenarios are (I) an across-the-board increase in which both classes get the same percentage increase, (II) a scenario with a moderately higher percentage increase for Class B, and (III) a slightly higher percentage increase for Class A, and (IV) a moderately higher percentage increase for Class B.

The common-sense answer is that the across-the-board scenario (I) should show no progress toward cost-based rates, Scenario II should indicate that revenues are moving farther away from costs, and Scenarios III and IV should show that revenues are moving slightly and modestly closer to allocated costs. The discussion of each metric below highlights where the metric produces results that are at odds with these expectations.

To evaluate the question as to whether there is consistent progress toward cost-based rates, the metrics are evaluated at both proposed rates in the "current" base rates proceeding, and for what the values would imply going into the next base rates case after a uniform increase in costs.

The Indexed Rate of Return Metric

The indexed rate of return metric is measured as the class rate of return divided by the system average rate of return, at current and proposed rates. If revenues are fully in line with

allocated costs, the class indexed rate of return is unity (1.0). Thus, if a class has an indexed rate of return at present rates that is higher than system average, it is deemed to be over-recovering costs, and conversely, where the indexed rate of is below unity, the class is under-recovering allocated costs.

As a standalone measure for relative cost performance, there is nothing wrong with the indexed rate of return metric – for any particular system average rate of return scenario, the farther a class's indexed rate of return is from unity, the farther it is from allocated costs.

Moreover, since an indexed rate of return of unity represents cost-based rates, it is conceptually appealing to conclude that if the indexed rate of return moves closer to unity, there is progress toward cost-based rates. Moreover, it is similarly appealing to conclude that progress toward cost-based rates could be measured by how much closer the index gets toward unity between current and proposed rates. Unfortunately, this intuitive approach fails in the actual arithmetic.

Utilities have used this argument for decades in Pennsylvania. While it is not clear why alternative methods have not been adopted, it may be that the metric is attractive to both utilities and regulators in that it tends to show significant progress toward cost-based rates when in fact there is little such progress. This then allows utilities to claim that they are following the cost standard without having to make politically unpopular decisions regarding differentiating rate increases among the various rate classes.

When applied in an actual example, the indexed rate of return fails even the simplest test. In the example shown, the current rates class rates of return are 2.50% and 5.71% for Classes A and B respectively, producing indexed rates of return of 0.625 and 1.429 relative to the system average return of 4.00%. When a 30% increase is applied to both classes, the system average rate of return rises to 8.00%, and the class returns rise to 6.25% and 10.00% respectively, yielding indexed rates of return of 0.781 and 1.250.

Thus, despite the fact that both classes get the same percentage increase and common sense says that there should be no progress toward cost-based rates, the indexed rate of return metric not only implies that there is progress, but that there is significant progress. The Class A indexed rate

of return moves from 0.625 to 0.781, which appears to imply that the class has moved 42 percent of the way to cost-based rates.[49]

The fallacy of this logic is shown in the implications for the next rate case. When costs increase, the system average rate of return falls back to its lower level and the indexed rate of return metrics all shift farther away from unity. Thus, as shown, an across-the-board increase in the current rate case followed by an across-the-board cost increase for the next case will demonstrate that, in fact, there is no progress toward cost-based rates and the indexed rates of return are right back where they started.

The other revenue increase scenarios show similar problems with the indexed rate of return metric. In Scenario II, despite a smaller percentage increase for the higher-cost Class A, the indexed rate of return again implies that there is progress toward cost-based rates, which is obviously nonsense. This is again demonstrated by the implications for the next base rates case, which understandably show that rates are farther out of line than they were going into the current rate case. It is simply unreasonable to believe that assigning larger percentage increases to the rate class that is already over-recovering costs will somehow reduce inter-class subsidies. And yet that is the implication of the indexed rate of return metric.

In Scenarios III and IV, the indexed rate of return does produce the correct directional answer, namely that rates are moving more into line with allocated cost. But the indexed rate of return metric implies that both scenarios result in enormous progress toward cost-based rates, when in fact there is relatively little progress, particularly in Scenario III. As shown in the example, despite a small differential in the rate increases, the indexed rate of return implies that revenues have moved 50 percent of the way toward allocated cost. Realistically, however, as shown in the implications for the next base rates case, the actual progress is much lower.

Thus, the indexed rate of return metric is a wholly unreliable guide for evaluating progress toward cost-based rates in a utility rate proceeding, because it (a) may show progress toward cost-

[49] "Progress" is measured by how much the metric has moved divided by how far it needs to move to become fully cost-based. Thus, in the residential class example, the index moves from 0.625 to 0.781, a difference of 0.156, compared to moving fully to cost-based rates, which would require the index to move from 0.625 to 1.000, a difference of 0.375. Progress is measured as 0.156/0.375, or 42 percent.

based rates when in fact revenues are moving farther away from costs, and (b) will overstate the magnitude of progress toward cost-based rates when progress is occurring.

The Dollar Subsidy Method

While the indexed rate of return metric is the most common approach used by Pennsylvania utilities, the Commission has also supported the use of the dollar subsidy metric. In an order involving the City of Bethlehem – Water Department, the Commission concluded:

> "As noted by the OSBA, the proper yardstick for measuring the degree of movement toward cost of service is the change in the absolute level of class subsidies at present and proposed rates."[50]

In the dollar subsidy method, the total cost to provide service is calculated using the method described above, in which each component to cost, including return and income taxes, is allocated to each cost. The difference between current rate revenues and the allocated cost is the dollar subsidy.[51]

In allocating the return and income tax costs under the "current rates" evaluation, the values used represent only the return that the utility would achieve and the income taxes that it would incur if it were assigned no rate increase. These values therefore do not represent the utility cost of capital, but simply residual values of what is left from current rate revenues after O&M, A&G, depreciation and other taxes are deducted.

When the dollar subsidy metric is applied to the four alternative revenue allocation proposals in the attached example, it implies the following:

- For the across-the-board increase, the dollar subsidy metric indicates that the dollar value of the revenue-cost difference increases under proposed rates, implying that rates

[50] *Pennsylvania Public Utility Commission v. City of Bethlehem -- Water Department*, Docket No. R-2020-3020256, Order entered April 15, 2021, at 36.

[51] This appendix uses the term "subsidy" as the difference between revenues and fully allocated cost in a utility cost allocation study. Theoretical economics generally defines subsidy based on incremental cost concepts, rather than fully allocated cost.

are moving farther away from costs. In dollar terms, that conclusion is correct, although in percentage terms the subsidies remain the same.

- When a larger increase is assigned to Class B, the dollar subsidy metric indicates correctly that rates are moving farther away from allocated cost, and that the problem will be worse with the next base rates proceeding.

- When a modestly larger increase is assigned to Class A, the dollar subsidy metric implies that there is no progress toward cost-based rates in the current rate proceeding, and that the situation will be worse in the next base rates case. In effect, even though the slightly higher rate increase for Class A will (eventually) lead to cost-based rates, the dollar subsidy method implies that there is no progress.

- When a materially larger increase is assigned to Class A, the dollar subsidy metric correctly indicates that there is progress toward cost-based rates.

Thus, overall, the dollar subsidy metric will tend to slightly understate progress toward cost-based rates, but the distortion is far smaller (and in the opposite direction) of that of the indexed rate of return metric.

<u>The Differential Rate of Return</u>

The differential rate of return metric is similar to the indexed rate of return metric, in that both approaches calculate class rates of return and current and proposed rates, and compares each class's return to the system average. However, where the indexed rate of calculates the *ratio* of class to average return, the differential rate of return calculates the *difference* between class and average rates of return. In the indexed rate of return, cost-based rates are achieved with an indexed rate of return of unity (1.0); for the differential rate of return, cost-based rates are achieved with a differential rate of return of zero.

When applied to the four revenue allocation scenarios in the example, the differential rate of return produces results that are nearly the same as the dollar subsidy method. That is, the differential rate of return calculation will slightly understate progress toward cost-based rates, but the results are much less distorted than those from the indexed rate of return metric.

Revenue-Cost Ratio

The revenue cost ratio is similar to the dollar subsidy metric, except rather than taking the difference between revenues and allocated costs, it takes the ratio of revenues to allocated cost. Like the indexed rate of return, cost-based rates are achieved at a revenue-cost ratio of unity (1.0 or 100 percent).

Unlike the indexed rate of return metric, however, the revenue-cost ratio generally does not distort the implications of a revenue allocation proposal. As shown in the example, in all four revenue allocation proposals, the revenue-cost ratio correctly indicates when there is progress toward cost-based rates and when there is not.

The only downside to this unadjusted revenue-cost ratio approach is that the progress toward cost-based rates in the current case is not the same as that going into the next base rates case. This results because the mix of operating costs allocated to each class is different from the mix of rate base costs. This minor distortion is addressed in the final metric below.

Normalized Revenue-Cost Ratio

The normalized revenue-cost ratio makes a technical correction to the revenue-cost ratio metric to reduce the distortion associated with using a non-cost parameter, namely the residual return and income tax costs, as a measure of cost at current rates. This metric uses fully allocated costs including the utility's allowed return on capital as the cost metric at both current and proposed rates. In this metric, however, the revenues at current rates are "normalized" by applying the system average rate increase to each class. Thus, in this metric, the current rates revenue-cost ratio is the revenues that would be earned from each class if an across-the-board rate increase were applied divided by the fully allocated class revenue requirement. This is then compared to the revenue-cost ratio that results from the actual proposed revenue allocation.

As shown in the attached example, this metric correctly shows the progress toward cost-based rates in each of the scenarios, and it also correctly predicts what each class' revenue-cost performance will be going into the next base rates case if there is no change in the underlying cost structure.

Summary

The indexed rate of return is a metric that has intuitive appeal, in that cost-based rates are achieved when the index is at unity (1.0), and that it would seem therefore that moving the index closer to 1.0 would represent progress toward cost-based rates.

Alas, it is not that simple. As shown in the examples attached, and as evidenced in hundreds of utility rate proceedings in Pennsylvania, the indexed rate of return is not a reliable metric for gauging progress toward cost-based rates for any particular revenue allocation proposal. It may give a directionally correct answer, and it may not. And even when it does correctly show progress, it implies that there is much more progress toward cost-based rates than actually exists.

Of the five metrics evaluated in this review, the indexed rate of return is the only metric to fail the test and imply that there is progress toward cost-based rates when there is none, and even when rates are moving substantially away from allocated cost.

All the other metrics evaluated in this review are superior to the indexed rate of return approach. The dollar subsidy and differential rate of return have a modest disadvantage in that they may imply that there is no progress toward cost-based rates when in fact some small progress is occurring. This is a relatively modest disadvantage since the distortion is much smaller than that in the indexed rate of return, and moreso because it will encourage Pennsylvania utilities and regulators to adopt revenue allocation proposals that are more aggressive in moving revenues into line with allocated cost, consistent with the legal standard that cost of service be the polestar criterion.

Overall, however, the revenue-cost metric, particularly the normalized revenue-cost metric, does not suffer from the distortions of any of the other methods, and is the most reliable of the methods on offer.

Comparison of Alternative Metrics for Evaluating Progress Toward Cost-Based Rates: Indexed Rate of Return Metric

	Across-The-Board Increase			Higher Class B Increase			Slightly Higher Class A Increase			Higher Class A Increase		
	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B
Current Rates												
(1) Current Revenue	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000
(2) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(3) Pre-Tax Return (Difference)	30,000	10,000	20,000	30,000	10,000	20,000	30,000	10,000	20,000	30,000	10,000	20,000
(4) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(5) Class Rate of Return (3)/(4)	4.00%	2.50%	5.71%	4.00%	2.50%	5.71%	4.00%	2.50%	5.71%	4.00%	2.50%	5.71%
(6) Indexed Rate of Return	1.000	0.625	1.429	1.000	0.625	1.429	1.000	0.625	1.429	1.000	0.625	1.429
Proposed Rates												
(7) Rate Increase (%)	30.0%	30.0%	30.0%	30.0%	25.0%	35.0%	30.0%	32.0%	28.0%	30.0%	35.0%	25.0%
(8) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(9) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(10) Pre-Tax Return (Difference)	60,000	25,000	35,000	60,000	22,500	37,500	60,000	26,000	34,000	60,000	27,500	32,500
(11) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(12) Class Rate of Return (10)/(11)	8.00%	6.25%	10.00%	8.00%	5.63%	10.71%	8.00%	6.50%	9.71%	8.00%	6.88%	9.29%
(13) Indexed Rate of Return	1.000	0.781	1.250	1.000	0.703	1.339	1.000	0.813	1.214	1.000	0.859	1.161
(14) Progress Toward Cost Based Rates		42%	42%		21%	21%		50%	50%		63%	63%
Next Base Rates Case												
(15) Cost Increase (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
(16) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(17) O&M/A&G Cost	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000
(18) Pre-Tax Return (Difference)	39,000	13,000	26,000	39,000	10,500	28,500	39,000	14,000	25,000	39,000	15,500	23,500
(19) Rate Base	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000
(20) Class Rate of Return (3)/(4)	4.00%	2.50%	5.71%	4.00%	2.02%	6.26%	4.00%	2.69%	5.49%	4.00%	2.98%	5.16%
(21) Indexed Rate of Return	1.000	0.625	1.429	1.000	0.505	1.566	1.000	0.673	1.374	1.000	0.745	1.291
(22) Progress Toward Cost Based Rates		0%	0%		-32%	-32%		13%	13%		32%	32%
	Observation: Indexed rate of return indicates that there is progress toward cost-based rates in current proceeding, but increases will never close the gap, as shown by next base rates case.			**Observation:** Indexed rate of return indicates that there is progress toward cost-based rates in current proceeding, but rates going into next proceeding are farther away from cost than for current case.			**Observation:** Indexed rate of return indicates that there is significant progress toward cost-based rates in current proceeding, but rates going into next case show only modest progress.			**Observation:** Indexed rate of return exaggerates progress toward cost-based rates in current proceeding.		

Comparison of Alternative Metrics for Evaluating Progress Toward Cost-Based Rates: Dollar Subsidy Metric

	Across-The-Board Increase			Higher Class B Increase			Slightly Higher Class A Increase			Higher Class A Increase		
	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B
Current Rates												
(1) Current Revenue	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000
(2) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(3) Pre-Tax Return (Allocated)	30,000	16,000	14,000	30,000	16,000	14,000	30,000	16,000	14,000	30,000	16,000	14,000
(4) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(5) Cost of Service (2)+(3)	100,000	56,000	44,000	100,000	56,000	44,000	100,000	56,000	44,000	100,000	56,000	44,000
(6) Subsidy	0	-6,000	6,000	0	-6,000	6,000	0	-6,000	6,000	0	-6,000	6,000
Proposed Rates												
(7) Rate Increase (%)	30.0%	30.0%	30.0%	30.0%	25.0%	35.0%	30.0%	32.0%	28.0%	30.0%	35.0%	25.0%
(8) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(9) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(10) Pre-Tax Return (Allocated)	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000
(11) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(12) Cost of Service	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000
(13) Subsidy	0	-7,000	7,000	0	-9,500	9,500	0	-6,000	6,000	0	-4,500	4,500
(14) Progress Toward Cost Based Rates		-17%	-17%		-58%	-58%		0%	0%		25%	25%
Next Base Rates Case												
(15) Cost Increase (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
(16) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(17) O&M/A&G Cost	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000
(18) Pre-Tax Return (Allocated)	39,000	20,800	18,200	39,000	20,800	18,200	39,000	20,800	18,200	39,000	20,800	18,200
(19) Rate Base	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000
(20) Cost of Service	130,000	72,800	57,200	130,000	72,800	57,200	130,000	72,800	57,200	130,000	72,800	57,200
(21) Subsidy	0	-7,800	7,800	0	-10,300	10,300	0	-6,800	6,800	0	-5,300	5,300
(22) Progress Toward Cost Based Rates		-30%	-30%		-72%	-72%		-13%	-13%		12%	12%
	Observation: Dollar subsidy correctly indicates that shortfall from Class B increases under proposed rates, and that dollar subsidy will be worse in next base rates case. Subsidy in percentage terms, however, would be the same.			**Observation:** Dollar subsidy correctly indicates that shortfall from Class B increases under proposed rates, and that dollar subsidy will be worse in next base rates case.			**Observation:** Dollar subsidy metric shows no progress toward cost-based rates, although subsidy as a percentage of rates declines.			**Observation:** Dollar subsidy metric correctly shows progress toward cost-based rates.		

Comparison of Alternative Metrics for Evaluating Progress Toward Cost-Based Rates: Differential Rate of Return Metric

	Across-The-Board Increase			Higher Class B Increase			Slightly Higher Class A Increase			Higher Class A Increase		
	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B
Current Rates												
(1) Current Revenue	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000
(2) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(3) Pre-Tax Return (Difference)	30,000	10,000	20,000	30,000	10,000	20,000	30,000	10,000	20,000	30,000	10,000	20,000
(4) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(5) Class Rate of Return (3)/(4)	4.00%	2.50%	5.71%	4.00%	2.50%	5.71%	4.00%	2.50%	5.71%	4.00%	2.50%	5.71%
(6) Differential Rate of Return	0.00%	-1.50%	1.71%	0.00%	-1.50%	1.71%	0.00%	-1.50%	1.71%	0.00%	-1.50%	1.71%
Proposed Rates												
(7) Rate Increase (%)	30.0%	30.0%	30.0%	30.0%	25.0%	35.0%	30.0%	32.0%	28.0%	30.0%	35.0%	25.0%
(8) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(9) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(10) Pre-Tax Return (Difference)	60,000	25,000	35,000	60,000	22,500	37,500	60,000	26,000	34,000	60,000	27,500	32,500
(11) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(12) Class Rate of Return (10)/(11)	8.00%	6.25%	10.00%	8.00%	5.63%	10.71%	8.00%	6.50%	9.71%	8.00%	6.88%	9.29%
(13) Differential Rate of Return	0.00%	-1.75%	2.00%	0.00%	-2.38%	2.71%	0.00%	-1.50%	1.71%	0.00%	-1.13%	1.29%
(14) Progress Toward Cost Based Rates		-17%	-17%		-58%	-58%		0%	0%		25%	25%
Next Base Rates Case												
(15) Cost Increase (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
(16) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(17) O&M/A&G Cost	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000
(18) Pre-Tax Return (Difference)	39,000	13,000	26,000	39,000	10,500	28,500	39,000	14,000	25,000	39,000	15,500	23,500
(19) Rate Base	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000
(20) Class Rate of Return (3)/(4)	4.00%	2.50%	5.71%	4.00%	2.02%	6.26%	4.00%	2.69%	5.49%	4.00%	2.98%	5.16%
(21) Differential Rate of Return	0.00%	-1.50%	1.71%	0.00%	-1.98%	2.26%	0.00%	-1.31%	1.49%	0.00%	-1.02%	1.16%
(22) Progress Toward Cost Based Rates		0%	0%		-32%	-32%		13%	13%		32%	32%
	Observation: Return differential indicates that shortfall from Class B increases under proposed rates. However, under this metric, the differentials going into the next base rates case will be the same as those going into the current case, meaning there is no change either way.			**Observation:** Return differential metric correctly indicates that shortfall from Class B increases under proposed rates, and that the shortfall will be worse in next base rates case. Metric overstates impact of current case.			**Observation:** Return differential metric shows no progress toward cost-based rates in current case, although modest progress results as shown by results going into next base rates case.			**Observation:** Return differential metric correctly shows progress toward cost-based rates in current case, although that progress is modestly understated.		

Comparison of Alternative Metrics for Evaluating Progress Toward Cost-Based Rates: Revenue-Cost Ratio

	Across-The-Board Increase			Higher Class B Increase			Slightly Higher Class A Increase			Higher Class A Increase		
	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B
Current Rates												
(1) Current Revenue	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000
(2) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(3) Pre-Tax Return (Allocated)	30,000	16,000	14,000	30,000	16,000	14,000	30,000	16,000	14,000	30,000	16,000	14,000
(4) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(5) Cost of Service (2)+(3)	100,000	56,000	44,000	100,000	56,000	44,000	100,000	56,000	44,000	100,000	56,000	44,000
(6) Revenue-Cost Ratio	100.0%	89.3%	113.6%	100.0%	89.3%	113.6%	100.0%	89.3%	113.6%	100.0%	89.3%	113.6%
Proposed Rates												
(7) Rate Increase (%)	30.0%	30.0%	30.0%	30.0%	25.0%	35.0%	30.0%	32.0%	28.0%	30.0%	35.0%	25.0%
(8) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(9) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(10) Pre-Tax Return (Allocated)	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000
(11) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(12) Cost of Service	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000
(13) Revenue-Cost Ratio	100.0%	90.3%	112.1%	100.0%	86.8%	116.4%	100.0%	91.7%	110.3%	100.0%	93.8%	107.8%
(14) Progress Toward Cost Based Rates		9%	11%		-23%	-20%		22%	24%		42%	43%
Next Base Rates Case												
(15) Cost Increase (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
(16) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(17) O&M/A&G Cost	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000
(18) Pre-Tax Return (Allocated)	39,000	20,800	18,200	39,000	20,800	18,200	39,000	20,800	18,200	39,000	20,800	18,200
(19) Rate Base	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000
(20) Cost of Service	130,000	72,800	57,200	130,000	72,800	57,200	130,000	72,800	57,200	130,000	72,800	57,200
(21) Revenue-Cost Ratio	100.0%	89.3%	113.6%	100.0%	85.9%	118.0%	100.0%	90.7%	111.9%	100.0%	92.7%	109.3%
(22) Progress Toward Cost Based Rates		0%	0%		-32%	-32%		13%	13%		32%	32%
	Observation: Revenue-cost ratio metric shows slight progress toward cost-based rates in current case, even though no progress will have occurred going into the next base rates case.			**Observation:** Revenue-cost ratio metric correctly shows negative progress toward cost-based rates.			**Observation:** Revenue-cost ratio metric correctly shows progress toward cost-based rates, but modestly overstates the progress as compared to the results going into the next base rates case.			**Observation:** Revenue-cost ratio metric correctly shows progress toward cost-based rates, but modestly overstates the progress as compared to the results going into the next base rates case.		

Comparison of Alternative Metrics for Evaluating Progress Toward Cost-Based Rates: Normalized Revenue-Cost Ratio

	Across-The-Board Increase			Higher Class B Increase			Slightly Higher Class A Increase			Higher Class A Increase		
	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B	Total	Class A	Class B
Current Rates												
(1) Current Revenue	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000	100,000	50,000	50,000
(2) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(3) Full Pre-Tax Return (Allocated)	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000
(4) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(5) Cost of Service (2)+(3)	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000
(5) Revenue-Cost Ratio	76.9%	69.4%	86.2%	76.9%	69.4%	86.2%	76.9%	69.4%	86.2%	76.9%	69.4%	86.2%
(6) Normalized Revenue-Cost Ratio	100.0%	90.3%	112.1%	100.0%	90.3%	112.1%	100.0%	90.3%	112.1%	100.0%	90.3%	112.1%
Proposed Rates												
(7) Rate Increase (%)	30.0%	30.0%	30.0%	30.0%	25.0%	35.0%	30.0%	32.0%	28.0%	30.0%	35.0%	25.0%
(8) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(9) O&M/A&G Cost	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000	70,000	40,000	30,000
(10) Pre-Tax Return (Allocated)	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000	60,000	32,000	28,000
(11) Rate Base	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000	750,000	400,000	350,000
(12) Cost of Service	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000	130,000	72,000	58,000
(13) Revenue-Cost Ratio	100.0%	90.3%	112.1%	100.0%	86.8%	116.4%	100.0%	91.7%	110.3%	100.0%	93.8%	107.8%
(14) Progress Toward Cost Based Rates		0%	0%		-36%	-36%		14%	14%		36%	36%
Next Base Rates Case												
(15) Cost Increase (%)	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%	30.0%
(16) Proposed Revenue	130,000	65,000	65,000	130,000	62,500	67,500	130,000	66,000	64,000	130,000	67,500	62,500
(17) O&M/A&G Cost	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000	91,000	52,000	39,000
(18) Full Pre-Tax Return (Allocated)	78,000	41,600	36,400	78,000	41,600	36,400	78,000	41,600	36,400	78,000	41,600	36,400
(19) Rate Base	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000	975,000	520,000	455,000
(20) Cost of Service	169,000	93,600	75,400	169,000	93,600	75,400	169,000	93,600	75,400	169,000	93,600	75,400
(20) Revenue-Cost Ratio	76.9%	69.4%	86.2%	76.9%	66.8%	89.5%	76.9%	70.5%	84.9%	76.9%	72.1%	82.9%
(21) Normalized Revenue-Cost Ratio	100.0%	90.3%	112.1%	100.0%	86.8%	116.4%	100.0%	91.7%	110.3%	100.0%	93.8%	107.8%
(22) Progress Toward Cost Based Rates		0%	0%		-36%	-36%		14%	14%		36%	36%
	Observation:			**Observation:**			**Observation:**			**Observation:**		
	Normalized revenue-cost ratio metric correctly shows zero progress toward cost-based rates.			Normalized revenue-cost ratio metric correctly shows negative progress toward cost-based rates.			Normalized revenue-cost ratio metric correctly shows progress toward cost-based rates.			Normalized revenue-cost ratio metric correctly shows progress toward cost-based rates.		

EXHIBIT RDK-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

Overview

Mr. Knecht has more than 40 years of economic consulting experience, focusing on the energy, utility, metals and mining industries. For the past 30 years, Mr. Knecht's practice has primarily involved providing analysis, consulting support and expert testimony in regulatory matters, primarily involving electric and natural gas utilities. Mr. Knecht's work includes many aspects of utility regulation, including industry restructuring, cost unbundling, cost allocation, rate design, rate of return, customer contributions, energy efficiency programs, smart metering programs, treatment of stranded costs and utility revenue requirement issues. He has consulted to state advocacy agencies, industrial customer groups, law firms, regulatory agencies, government agencies and utilities, in both the United States and Canada. He has provided expert testimony in more than one hundred separate utility proceedings.

In addition to his work with regulated utilities, Mr. Knecht has consulted on international industry restructuring studies, prepared economic policy analyses, participated in a variety of litigation matters involving economic damages, and developed energy industry forecasting models.

Mr. Knecht served as a Principal of IEc for 33 years, and as its Treasurer for 15 years. He is currently an independent consultant who remains affiliated with IEc.

Education

Master of Science, Management (Applied Economics and Finance), Sloan School of Management, M.I.T.

Bachelor of Science, Economics, Massachusetts Institute of Technology

Select Project Experience

For more than 25 years, Mr. Knecht has provided consulting services, analysis and expert testimony before the Pennsylvania Public Utility Commission on all manner of regulatory proceedings to the **PENNSYLVANIA OFFICE OF SMALL BUSINESS ADVOCATE**. In addition to expert testimony, Mr. Knecht has assisted OSBA with the development of public policy positions, litigation strategy, and longer term strategy.

For the **ATTORNEY GENERAL OF THE STATE OF RHODE ISLAND**, Mr. Knecht provided consulting and expert witness services in an acquisition proceeding involving PPL Corporation's proposed acquisition of Narragansett Electric from National Grid. Mr. Knecht's testimony addressed financial, economic, environmental, tax, operating cost and rate implications.

For the **NEW BRUNSWICK PUBLIC INTERVENER,** Mr. Knecht provides consulting and expert witness services in a variety of regulatory proceeding before the New Brunswick Energy and Utilities Board involving New Brunswick Power, Enbridge Gas New Brunswick, and petroleum products. Mr. Knecht has addressed issues of load forecasting, costs forecasting, cost of capital, allocation of corporate overhead costs, utility cost allocation, revenue allocation, market-based rate design, cost-based rate design, and rate decoupling.

For **L'ASSOCIATION QUÉBÉCOISE DES CONSOMMATEURS INDUSTRIELS D'ÉLECTRICITÉ (AQCIE) AND LE CONSEIL DE L'INDUSTRIE FORESTIÈRE DU QUÉBEC (CIFQ)**, Mr. Knecht provided analysis, consulting advice and expert testimony before the Régie de l'énergie in regulatory matters involving Hydro Québec Distribution and TransÉnergie. This work includes revenue requirement, power purchasing, cost allocation, treatment of cross-subsidies, and rate design.

For the **INDEPENDENT POWER PRODUCERS SOCIETY OF ALBERTA**, Mr. Knecht provided consulting advice, analysis and expert testimony before the Alberta Energy and Utilities Board in a series of proceedings involving the restructuring of the electric utility industry, the unbundling of rates, and the development of transmission rates.

EXHIBIT RDK-2

REFERENCED INTERROGATORY RESPONSES

OSBA-I-1

OSBA-I-2

OSBA-I-4

CONFIDENTIAL OSBA-I-6*

CONFIDENTIAL REVISED OSBA-I-7*

CONFIDENTIAL OSBA-I-8*

CONFIDENTIAL OSBA-I-9*

OSBA-I-10

***Confidential Interrogatory Responses will be included in the OSBA's Confidential Version of Direct Testimony**

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2022-3031113

Response of PECO Energy Company
To Interrogatories of the
Office of Small Business Advocate
OSBA Set I

Response Date: April 29, 2022

OSBA-I-1

Reference PECO Statement No. 6 and associated exhibits:

a. Please provide working electronic versions of Exhibits JD-1, JD-2, JD-3, JD-4, JD-5, and JD-6 in MS Excel electronic format with formulae intact.
b. To the extent available, please provide a version of Exhibit JD-6 page 2 with allocators for TS-F and TS-I split between customers above and below the tariff demarcation of 18,000 mcf per year, with supporting workpapers in MS Excel electronic format.
c. Please provide any cost analyses prepared by PECO for the relative cost to serve the smaller and larger customers (above and below 18,000 mcf/year) in the TS-F and TS-I rate classes.

RESPONSE:

a. Please see Confidential Attachment OSBA-I-1(a) for PECO's class of service working electronic versions of Exhibits JD-1, JD-2, JD-3, JD-4 and JD-5 (page 2 to page 19) in excel format with formula intact. Please note that, while the data in Confidential Attachment OSBA-I-1(a) are not considered confidential, PECO's Class Cost of Service Model is proprietary to PECO and, therefore, confidential.

   Refer to Attachment OSBA-I-1(b) for guidelines on using PECO's Proprietary Class Cost of Service Model.

Refer to Attachment OSBA-I-1(c) for Exhibit JD-5, page 1 in excel format.

Refer to Attachment OSBA-I-1(d) for Exhibit JD-6 in excel format.

b. Please note the requested data is not available. The Company's cost-of-service does not split customers based on consumption capability of above and below 18,000 Mcf per year in rate classes TS-F and TS-I.

c. Please see the response to b. above.

THE CONFIDENTIAL ATTACHMENT TO THIS RESPONSE IS PROVIDED ONLY TO THOSE WHO HAVE EXECUTED NON-DISCLOSURE AGREEMENTS UNDER PROTECTIVE ORDER.

Responsible Witness: Jiang Ding

Class Cost of Service Model (COS) User Guidelines
(PECO COS Model)

The class cost of service model (COS) provided to the authorized user is a proprietary model. It has been protected, but allows the user to verify inputs, change input data, and change the allocation basis of line items.

Open COS model, Activate Excel Macros, and Review Add-In Menu

1. Once the COS model has been opened and the Excel Macros invoked, the COS menu will appear in the Add-Ins menu of the Excel Ribbon. If the COS menu options do not appear in the Add-Ins the COS model will not be fully functional.
    a. If user receives the COS model via email, then the user will need to download the COS model to the user hard drive, then open from user drive, accept terms and the model will fully function.

COST OF SERVICE (worksheet) Allocation

2. To verify the allocated costs with the COST OF SERVICE sheet, select a line item with an allocation factor such as “DPKDAYP” on Excel row 231 of the COST OF SERVICE sheet. Multiply the TOTAL COMPANY INPUT BALANCE (Excel column Y) by the allocation factor ratios “DPKDAYP” on Excel row 1276, found in the Allocation Proportions – RATIO TABLE section (beginning in Excel row 1271).

    For example, if the user wants to audit or verify the amount allocated to RESID (COST OF SERVICE sheet, Excel column F) customer class for “311- Liquefied Petroleum Gas Equipment,” (COST OF SERVICE sheet, Excel row 231) which PECO has assigned an Allocation Basis of “DPKDAYP” (i.e., Demand Production), the steps are as follows:

    A. First, scroll to COST OF SERVICE sheet, Excel column Y, which contains a line item input balance number of $14,334 for the Liquefied Petroleum Gas Equipment row.
    B. The RESID class (Excel column F) of this same row shows the user that $9,668 is allocated to that customer class.
    C. If the user wants to see how the $9,668 dollars are allocated to the customer class, first go to the COS Menu and select View Schedules, Allocation Proportions, Excel cell F1276. This will show the user that 0.67450 of those dollars are assigned to the RESID class.

To see where the 0.67450 comes from, the user can either select that cell, which will show the user the formula that derives that percentage, or the user can go to the COS Menu and select View Schedules, Allocation Factors, Excel line 976), which will show the user the Capacity Production demands. The RESID class peak day demand can be divided by the Total Gas Division peak day demands (Excel cell E976) to derive the 0.67450.

D. The user can also verify that the sums of the allocated columns of rate classes equal the total company because the "TOTAL GAS DIVISION" column E for the "311- Liquefied Petroleum Gas Equipment," Excel row 231 sums up the amounts for each customer class, and that number equals the line item Input Balance in the COST OF SERVICE sheet, Excel column Y.

FUNCTIONS (worksheet) and UNBUNDLED (worksheet) – Note that these cost component numbers are **values** since they are copied in from the 16 cost component COS studies that are created as described below.

3. To verify the numbers within the FUNCTIONS and UNBUNDLED sheets of the COS for each classification component (capacity, commodity, and customer) or each functionalization component (i.e. Production, Storage, Purchased Gas, Service Investment, Meter Investments, etc.) the user must first create the 16 individual cost component files.
    a. This can be accomplished by selecting the Add-Ins COS, Functions/Components, Create Functions/Components Schedules (this also updates the FUNCTIONS and the UNBUNDLED sheets in the COS model). These numbers can then be compared to the numbers found in the FUNCTIONS and UNBUNDLED sheets in the COS Model.
    b. The allocations can also be verified in each of these 16 cost component files as described above.
    c. Note that a list of the 16 component files can be found by selecting the Add-Ins COS, Component/Function Information Table, View Table.
4. The FUNCTIONS sheet of the COS model summarizes the numbers found in the TOTAL ELECTRIC DIVISION column (Excel column E) for each of the 16 component.
5. The UNBUNDLED sheet of the COS model summarizes the – Total Revenue Requirements for each cost component. These numbers will appear as values since they are copied in as values from the other 16 component files.

6. The UNBUNDLED sheet of the COS model summarizes these cost components by class at present rates (Excel row 912) and at a claimed uniform rate of return (Excel row 1012).

DATA INPUT CHANGES

7. To change input data within the protected version of the COS model, go to the Add-Ins menu item COS, sub-menu item “Data Input” and select a sub-menu data item to be entered or changed. By selecting a sub-menu item the user will be directed to the unprotected areas of the COS model where the data can be entered (changed).
8. In addition to data changes, the allocation basis of a line item can be changed by entering a pre-defined allocation factor name into the Allocation Basis (Excel Column D) column of a line item.
    a. As an example, if one would like to allocate a line item from a salaries and wages allocation factor “SALWAGES” to a total plant “TOTPLT” allocation factor, they would simply need to change the allocation basis (COST OF SERVICE sheet, Excel column D) from “SALWAGES” to “TOTPLT”, which is a previously defined allocation factor that can be found in the Internally Developed Proportions Table section (Excel row 1271) of the Allocation Proportions Table – Ratio Table.
9. As previously noted all areas of data input can be changed. The data input areas can be found in the COS model menu, COS, Data Input menu option located in the Excel Add-Ins. Menu.
10. The COS model FUNCTIONS and UNBUNDLED sheets must be updated, as discussed in Item 3, if any input data has been changed or if the allocation basis of any line item has been changed.

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2022-3031113

Response of PECO Energy Company
To Interrogatories of the
Office of Small Business Advocate
OSBA Set I

Response Date: April 29, 2022

OSBA-I-2

Reference Exhibit JD-6:

a. Please provide all supporting workpapers for development of the external allocation factors in Exhibit JD-6 in MS Excel electronic format, with formulae intact.
b. In MS Excel electronic format, please provide supporting workpapers for the derivation of the (much improved!) peak sendout, peak mains, and peaks NCP values in Exhibit JD-6, page 5, and page 18. Please segregate the peak demand allocators for rate TS-F between customers above and below 18,000 mcf per year.
c. Please provide an MS Excel file with monthly historical deliveries (calendarized if possible) and number of customers for each rate class as defined in the cost allocation study, with TS-F and TS-I segregated between customers above and below 18,000 mcf per year, for the past five years. Please include the historical heating degree days for each month.
d. For each TS-F customer for each of the past five winter seasons, please provide the customer's contract demand and the top five actual daily loads with the date for each, in MS Excel electronic format. Please also identify any instances when PECO was unable to meet TS-F customer overruns due to distribution constraints.
e. For each TS-I customer, please identify the number of winter season interruptions due to insufficient distribution capacity in each of the past five years, showing date and duration of interruption, in MS Excel electronic format.
f. Re page 18, to the extent known, please explain why the Large High Load Factor rate class has a load factor of 28.9 percent over the five-year historical period.

g. Please provide page 7 of Exhibit JD-6. If a confidentiality agreement is required, please explain why that is necessary and provide a suitable agreement to OSBA in a timely manner.
h. Please provide the tabular response to SDR-COS-7 in MS Excel electronic format, showing number of meters, an explanation for the meter sizes, and the cost for each meter size.
i. Regarding Exhibit JD-6 page 8, please provide a ten-year history of services costs in this format and break out the C&I services costs for each year from 2012 to 2021 by rate class or by size of customer in as much detail as possible.
j. Re Exhibit JD-6, please provide the current number of actual service lines by rate class as defined in the cost allocation study.
k. Regarding Exhibit JD-6 page 13, please provide a similar table showing the ratio of write-offs as a percentage of revenue for each year and each rate class. Please indicate whether the write-offs and revenues include or exclude those related to gas supply costs.
l. Regarding Exhibit JD-6, page 14, please provide this table for each of the past three years. Please also explain why interest on deposits does not parallel deposits.
m. Regarding Exhibit JD-6, page 6, please describe the basis for the storage split between winter sales and transportation and provide supporting calculations for the value used.
n. Reference Exhibit JD-6, page 15: Please provide supporting workpapers for this exhibit in MS Excel electronic format, including PGC volumes and the PGC rate. Please include an explanation of the basis for the PGC rate.
o. Reference Exhibit JD-6, page 16: Please provide supporting workpapers for this allocator in MS Excel electronic format, including the volume basis and the rate for the BSC.

RESPONSE:

a. Please refer to Attachment OSBA-I-1(d).

b. Please refer to Attachment OSBA-I-1(d), page 5 and page 18. The peak demand allocator for rate TS-F is a budget and the Company does not budget this value for customer at above and below 18,000 Mcf per year.

c. Please refer to Attachment OSBA-I-1(d), page 18, excel lines 50 through 111 for monthly calendarized usage, customer numbers and heating degree days for rate classes R, GC, L and MVF. Refer to Attachment OSBA-I-2(a) for monthly

calendarized usage and customer numbers for rate classes MVI, TSF and TSI, with TS-F and TS-I segregated between customers above and below 18,000 Mcf per year.

d. Please refer to Attachment OSBA-I-2(b) for the contract demand and the top five daily load days for each TS-F customer for each of the last five winters. There were no instances when PECO was unable to meet TS-F customer overruns due to distribution system constraints.

e. Please see Attachment OSBA-I-2(c). For each of the listed interruptions all TSI customers were interrupted.

f. Large High Load Factor Service (Rate L) is available to provide firm sales service to large, high load factor customers. Currently, there are five customers that employ Rate L in this capacity as their primary form of service ('Pure' L customers). Rate L also serves another function. With the prior approval of the Commission, the Company made Rate L available to customers on Rate TS-F – Gas Transportation Service-Firm as Standby Sales Service. The sales at page 18 included the sales to the 'Pure' L customers and the sales from Standby Sales Service. The customer counts at page 18 included the 'Pure' L customers. Standby Sale Service customers are included in TS-F. The sales and customers as noted were used in the calculation of the 28.9% L load factor.

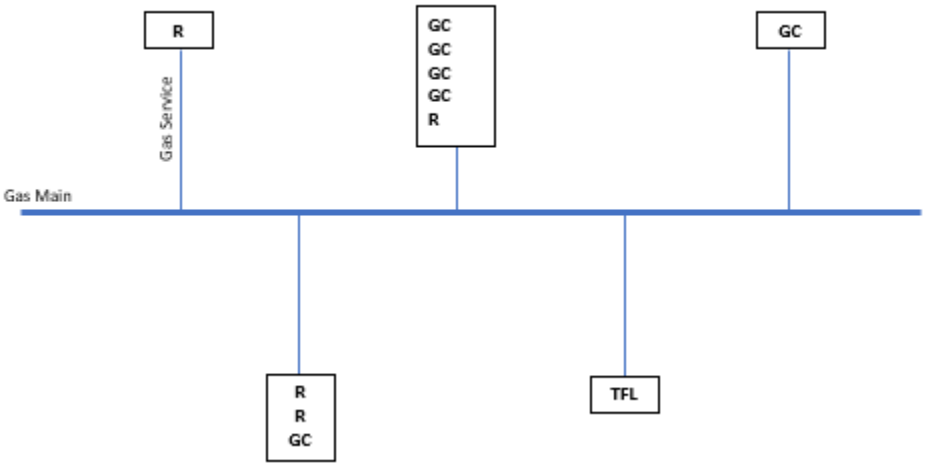
g. Please see Confidential Attachment OSBA-I-2(d). This attachment contains sensitive customer information, such as usage and gas main costs. It would be easier to determine the customer identity due to the very limited number of customers in the attachment.

h. Please see Attachment OSBA-I-2(e).

i. Please see Attachment OSBA-I-2(f). The Company does not comprehensively track the service lines by rate classes or by size of customer within C&I category.

j. The current number of actual service lines by rate class is not available because there are many service lines serving multiple customers and these service lines can have different rate class combinations.

Please see the illustrative chart below:



k. Please see Attachment OSBA-I-2(g). The write-offs and revenues include gas supply costs.

l. Please refer to Attachment OSBA-I-1(d), page 14, excel lines 22 to 62, 82 to 118 for 'Deposits' and 'Forfeited Discounts' in each year from 2019 to 2021, respectively. The table below shows 'Advances' in 2019 and 2020 (2021 advances are shown on page 14 of Exhibit JD-6), and 'SEHP' from 2019 to 2021. There was no cost in 'Grant' from 2019 to 2021. Note that interest rates on 'Deposits' are different for residential and non-residential rate classes, so interest rates on deposits do not parallel deposits. Refer to OSBA-I-1(d), page 14, column J for the interest rates.

	Advances ($000s)		**SEHP ($000s)**		
	2019	2020	2019	2020	2021
Residential	891	1,346	1,122	1,184	1,151
GC	191	124			

m. The storage split between winter sales and transportation was based on the value for transportation approved by the Commission as part of the Company's most recent PGC proceeding at Docket No. R-2021-3025629.

n. Please see Attachment OSBA-I-2(h). The rate used in Exhibit JD-6, page 15 is the commodity charge component of the PGC rate. The variable portion of the commodity charge was calculated by applying the annual growth rate of the full year

average Henry Hub Natural Gas Futures Price projected at the time of the PGC forecast to the prior year average Henry Hub Price. Additionally, a monthly shape of the Henry Hub was applied to the variable portion of the commodity charge by applying the ratio of the forecasted monthly price to the full year average price. Henry Hub prices were sourced on 11/16/2021 from https://www.cmegroup.com/markets/energy/natural-gas/natural-gas.settlements.html. The fixed portion of the commodity charge was kept flat to the most recent actual (December 2021).

o. Please see Attachment OSBA-I-2(i).

THE CONFIDENTIAL ATTACHMENT TO THIS RESPONSE IS PROVIDED ONLY TO THOSE WHO HAVE EXECUTED NON-DISCLOSURE AGREEMENTS UNDER PROTECTIVE ORDER.

Responsible Witness: Jiang Ding

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2022-3031113

Response of PECO Energy Company
To Interrogatories of the
Office of Small Business Advocate
OSBA Set I

Response Date: April 29, 2022

OSBA-I-4

Reference Exhibit JAB-4:

a. Please provide a MS Excel electronic version of this exhibit with formulae intact.
b. Please explain why the implied present rates customer charge for the residential class is $13.6257. . . per customer per bill.
c. Please provide a five-year annual history of Rate GC billing determinants with volumes split between the first and second commodity blocks.
d. Please explain the apparent shift in volumetric billing determinants from the 2020 base rates case to the current case for Rate GC from the first commodity block to the second block.
e. Please provide supporting workpapers for the development of the Rate GC volumetric billing determinants by block.
f. Please estimate the percentage of Rate GC bills below 200 mcf and above 200 mcf based on normal weather. Please provide your calculations.
g. Please provide any cost analysis prepared by the Company for the proposed rate differential between the first block and tail block Rate GC commodity charges.
h. In MS Excel electronic format, please provide monthly throughput for each Rate GC customer for the most recent 12-month period.
i. To the extent not elsewhere provided, please show the derivation of the present rates DSIC revenues for each rate class. Please explain any material differences between rate class for the DSIC percentage.
j. Please provide supporting calculations for each annualization adjustment. Please include an explanation for the nature of the Rate TCS annualization adjustment.

k. Please explain why charges credited to the PGC are included in present rates for Rate TS-F but not in proposed rates. Please include an explanation as to whether this accounting implicitly shifts PGC cost responsibility into base rates.
l. Regarding the TS-F proof of revenue, please break out the volumes and revenues for the negotiated gas sales between over 18,000 and under 18,000 (if any) mcf per year.
m. Please reconcile the TS-I volumes reported in Exhibit JAB-4 with those shown in Exhibit JD-6, page 2 line 6.

RESPONSE:

a. Please see Attachment OSBA-I-4(a).

b. The implied rate of $13.6257. . . per customer bill was the numerical value applied in PECO's June 30, 2021 compliance filing for Docket No. R-2020-3018929. The Company leveraged this value in its budget for the fully projected future test year ("FPFTY") ending December 31, 2023. The same value is therefore included in the Company's proof of revenue under present rates.

c. Please see Attachment OSBA-I-4(b).

d. The Company revised the methodology used to estimate the projected volumetric billing determinants. In the current case, the Company based its estimates on the actual Rate GC monthly usage billed in each block over five previous years, from both a budgeting and proof of revenues perspective. In the Company's 2020 case, the estimates for the proof of revenues were based on the Historical Test Year rather than a five-year average and required adjustment to ensure that projected revenues aligned with the Company's prior budgeting methodology.

e. Please see Attachment OSBA-I-4(c).

f. The Company does not estimate the percentage of Rate GC bills below 200 mcf and above 200 mcf based on normal weather.

g. No such cost analysis is available.

h. Please see Attachment OSBA-I-4(d).

i. Please see Attachment OSBA-I-4(e). The Company's intent was to distribute DSIC-revenue among the rate classes based on total distribution base rate revenues,

including both customer charge revenues and variable distribution charge revenues. In preparing this response, the Company discovered that it unintentionally distributed these costs based only on variable distribution revenues. The Company will correct this in a revised version of Exhibit JAB-4 as part of its rebuttal testimony. Attachment OSBA-I-4(e) demonstrates the variance between DSIC revenues as filed and DSIC revenues to be submitted in rebuttal.

j. Please refer to the Company's Exhibit MJT-1, page 52 of 87, Schedule D-5A for the support calculations of annualization adjustment.

   Please refer to Company Statement No. 3, Direct Testimony of Mike Trzaska, Page 27, Q&A 58, for the explanation of the nature of the annualization adjustment for each customer class, including TCS.

k. The charges credited to the PGC in the Company's transportation rates are not distribution revenues, and so the Company should not have included these revenues as "credited to PGC" in total distribution base rate revenues under present rates. The Company will modify Exhibit JAB-4 to exclude the PGC-related revenues under present rates as part of its rebuttal testimony.

l. The entire projected negotiated gas sales volume and revenue for Rate TS-F corresponds to one negotiated gas customer using more than 18,000 Mcf per year. The Company does not have any negotiated gas customers on Rate TS-F using less than 18,000 Mcf per year.

m. TS-I volumes shown in Exhibit JD-6, page 2, line 6 are based on PECO's budget and match the sum of the TS-I "Commodity TSI Mcf", "Commodity TSF Mcf", and "Negotiated Gas Sales" volumes shown in Exhibit JAB-4. The variance is the additional mcf in Exhibit JAB-4 labeled "Additional Commodity (15 days TCQ)". For customers who elect TS-I and TS-F firm backup service, the Company's Rate TS-F requires a minimum volume of firm gas per month equal to 15 times the customer's daily Transportation Contract Quantity (TCQ). If a customer's transported firm quantity plus their purchases under standby sales for a given month are less than this minimum volume, additional commodity charges will be added to the customer's bill for that month, as specified by the terms of the Rate TS-F monthly minimum charge in PECO's Gas Service Tariff. The "Additional Commodity" mcf represents a projection of these additional minimum charges, as opposed to actual volumes.

Responsible Witness: Joseph A. Bisti

Five-year annual history of Rate GC billing determinants with volumes split between the first and second commodity blocks

Year	<= 200 MCF	> 200 MCF
2017	14,189,161	4,961,649
2018	16,056,417	6,442,180
2019	15,506,798	6,328,091
2020	14,159,868	5,264,960
2021	15,087,973	6,100,499

Pennsylvania Public Utility Commission
v.
PECO Energy Company – Gas Division

Docket No. R-2022-3031113

Response of PECO Energy Company
To Interrogatories of the
Office of Small Business Advocate
OSBA Set I

Response Date: April 29, 2022

OSBA-I-10

Reference PECO Statement No. 7 at 22-23, and Attachment SDR-COS-15(a), Customer 5:

a. Please provide PECO's evidence that the customer's potential to relocate outside Pennsylvania is economically credible.
b. Please provide the bypass cost estimate from the customer, with PECO's assessment of its credibility.

RESPONSE:

a. The Company has no evidence indicating that Customer 5 has the potential to relocate outside of Pennsylvania as an alternative to PECO gas service.

b. The bypass cost estimate provided to the Company by Customer 5 totals approximately $19.55 million. The Company has no reason to believe that this estimate lacks credibility.

Responsible Witness: Joseph A. Bisti

EXHIBIT RDK-3

ELECTRONIC WORKPAPERS OF ROBERT D. KNECHT

RDK WP1 – Near Replication of PECO Gas COSS

RDK WP2 – TS-F Design Day Demand Review

RDK WP3 – Rate GC Monthly Loads

RDK WP4 – TS-F/TS-I Load Factor Analysis

RDK WP5 – Metrics for Progress Toward Cost-Based Rates Example

*The electronic workpapers for this exhibit are in excel format and will be emailed to all parties simultaneous to service of Direct Testimony

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3031113**
PECO Energy Company (Gas Division)	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Direct Testimony labelled OSBA Statement No. 1 and associated Exhibits RDK-1 through RDK-3 are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: June 22, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3031113**
	:	
PECO Energy Company-Gas Division	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

Laura J. Antinucci, Esquire
Barrett C. Sheridan, Esquire
Mackenzie C. Battle, Esquire
Darryl A. Lawrence, Esquire
Office of Consumer Advocate
555 Walnut Street, 5th Floor
Harrisburg, PA 17101
lantinucci@paoca.org
bsheridan@paoca.org
mbattle@paoca.org
Darryllwarence@paoca.org
(Counsel for OCA)

Scott B. Granger, Esquire
Bureau of Investigation & Enforcement
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
sgranger@pa.gov

Byron Goldstein
2365 Geneva Avenue
Glenside, PA 19038
BGoldmarketing@RCN.com

The Honorable F. Joseph Brady
Administrative Law Judge
Pennsylvana Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107
fbrady@pa.gov

Anthony E. Gay, Esq.
Jack R. Garfinkle, Esq.
Brandon J. Pierce, Esq.
Caroline S. Choi, Esq.
PECO Energy Company
2301 Market Street
P.O. Box 8699
Philadelphia, PA 19101
anthony.gay@exeloncorp.com
jack.garfinkle@exeloncorp.com
brandon.pierce@exeloncorp.com
caroline.choi@exeloncorp.com

Kenneth M. Kulak, Esq.
Mark A. Lazaroff, Esq.
Brooke E. McGlinn, Esq.
Catherine G. Vasudevan, Esq.
Morgan, Lewis & Bockius LLP
1701 Market Street
Philadelphia, PA 19103
ken.kulak@morganlewis.com
mark.lazaroff@morganlewis.com
brooke.mcglinn@morganlewis.com
catherine.vasudevan@morganlewis.com

Karl R. Pavlovic
PCMG & Associates LLC
22 Brookes Avenue
Gaithersburg, MD 20877
OCAPECOGAS2022@paoca.org

Roger D. Colton
Fisher Sheehan & Colton
34 Warwick Road
Belmont, MA 02478
OCAPECOGAS2022@paoca.org
Consultant for OCA

Richard G. Webster, Jr., VP
Regulatory Policy & Strategy
PECO Energy Company
2301 Market Street - S15
Philadelphia, PA 19103
dick.webster@exeloncorp.com

DATE: June 22, 2022

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney I.D. No. 77538

COMMONWEALTH OF PENNSYLVANIA

July 21, 2022

The Honorable F. Joseph Brady
Administrative Law Judge
Pennsylvania Public Utility
Commission 801 Market Street,
Suite 4063 Philadelphia, PA 19107

Re: Pennsylvania Public Utility Commission v. PECO Energy Company – Gas Division / Docket No. R-2022-3031113

Dear Judge Brady:

Enclosed please find the Rebuttal Testimony and Exhibits of Robert D. Knecht, , labeled OSBA Statement No. 1-R, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: **PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)**
Robert D. Knecht
Parties of Record

OSBA Statement No. 1-R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3031113**
PECO Energy Company (Gas Division)	:	

Rebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation

Date Served: July 21, 2022

Date Submitted for the Record: August 11, 2022

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. <u>Introduction and Overview</u>

Q. Please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct testimony and associated exhibits earlier in this proceeding, and my qualifications were detailed therein.

Q. What is the purpose of this rebuttal testimony?

A. This rebuttal testimony responds to the cost allocation and revenue allocation recommendations of Bureau of Investigation and Enforcement ("I&E") witness Esyan A. Sakaya, Pennsylvania Office of Consumer Advocate ("OCA") witness Karl R. Pavlovic, and Philadelphia Area Industrial Energy Users Group ("PAIEUG") witness Billie S. LaConte.

This testimony also addresses errors in my direct testimony that were flagged by other parties in the discovery process.

2. <u>Cost Allocation</u>

Q. What cost allocation issues have been raised by the intervenors in this proceeding?

A. The following issues have been addressed:

Mains Classification/Allocation: I&E, OCA, PAIEUG and OSBA

Peak Demand Determination: PAIEUG and OSBA

Allocation to Flex Rate Customers: I&E and OSBA

Q. Please summarize the positions of the parties regarding mains cost allocation, compared to the positions taken by the parties in the last PECO Gas base rates case at Docket No. R- R-2020-3018929.

A. The parties' positions are as follows:

- PECO Gas: Proposes to use a load-factor weighted average-and-excess ("A&E") methodology for allocating mains costs, with zero excess demand costs for the

interruptible service rate classes (MV-I, IS, TCS and TS-I). This method results in an allocation that is virtually identical to a non-coincident peak ("NCP") demand allocation method, where interruptible class NCP is set equal to average demand. This approach is consistent with the Company's approach in the last base rates case.

- OCA: OCA Witness Pavlovic supports the use of the A&E methodology, on the grounds that the PECO system has substantial diversity in customer peak demands. In the last base rates case, OCA Witness Glenn A. Watkins supported the use of a 50/50 peak-and-average ("P&A") approach, in which peak demands for interruptible service are set to zero.

- I&E: I&E Witness Esyan A. Sakaya advocates use of a 50/50 P&A allocation approach for mains, with peak demands for interruptible customers set at average day demand. In the 2020 base rates case, I&E Witness Ethan H. Cline supported the Company's use of the A&E methodology (I&E Statement No. 3-SR at 16).

- PAIEUG: PAIEUG Witness Billie S. LaConte has supported the use of the Company's A&E allocator, in both this proceeding and the 2020 base rates case.

- OSBA: I supported the Company's use of the A&E method in this case, consistent with the Commission's decision for PECO Gas in its last base rates proceeding at Docket No. R-2020-3019829. In that proceeding, I supported the P&A methodology consistent with the Commission's decision in the then just-completed Columbia Gas proceeding at Docket No. R-2020-3018835.

I address the OCA and I&E analysis below.

Q. Please comment on Dr. Pavolvic's analysis.

A. Consistent with the Commission's decision in the last PECO base rates case, Dr. Pavlovic relies on the A&E allocation method for mains costs in this proceeding. However, he does so based on his analysis of load diversity on the PECO gas distribution system. Dr. Pavlovic correctly indicates that load diversity is generally measured as the ratio of non-coincident peak ("NCP") demands to system coincident peak ("CP") demands, with a ratio of unity

implying zero load diversity.[1] When customers peak at different times, certain aspects of utility plant benefit from cost economies associated with that diversity, because those assets need only be sized to meet the CP demand, and not the sum of the individual customer peaks.[2] However, in this case, the PECO Gas analysis does not demonstrate that there is any material load diversity on its system. For most of its firm service rate classes (GR, GC, L, MV-F), PECO calculates both its CP and NCP demands based on demand under extreme weather conditions (i.e., "design day" demand), all with zero load diversity. For its interruptible service classes (TS-I, IS, MV-I and TCS), PECO Gas simply assumes that the class NCP demand is equal to the class average day demand for cost allocation purposes, with no supporting analysis of peak loads or load diversity. For its TS-F class, PECO Gas assumes that "TCQ" contract demands equal both CP and NCP demands, again with zero diversity.[3] Thus, the only "diversity" of demands in PECO's analysis is arbitrary assumption about interruptible customer demands for cost allocation purposes.

More specifically, I respectfully disagree with the following observations made by Dr. Pavlovic:

- At pages 4-5, Dr. Pavlovic states that the system NCP is 923,500 mcf/day and the CP is 861,000 mcf/day, for a diversity ratio of 1.07. None of these values is accurate. The 861,000 value is the system coincident peak sendout excluding firm service Rate TS-F, and it also excludes the peak demands for the interruptible service classes. The 923,500 value is the firm CP load, as it includes the 861,00 mcf value plus the design day sendout for all firm classes (including Rate TS-F). The actual value used in the PECO Gas cost allocation study for NCP demand is 947,434 mcf/day (which includes the assumed interruptible NCP demands), and for CP demand is 923,500 mcf/day, with a diversity

[1] In considering diversity, NCP can be evaluated either as the peak combined load of all customers within a class, or the sum of individual customer peaks.

[2] As discussed further below, demand diversity is much less beneficial to gas distribution systems which must be sized to meet local demands than for electric generation or electric/gas transmission systems which serve the diversified demands.

[3] More on this issue below.

ratio of 1.026.[4] As noted above, PECO Gas reports zero diversity for the GR, GC, L, MV-F and TS-F rate classes.

- In Table 1, Dr. Pavlovic reports class-specific values for "NCP Demand." The values shown in that table are not the PECO Gas NCP demands, but are in fact a weighted average of average day demands and excess day demands.

- In Table 1, Dr. Pavlovic calculates the ratio of excess demand (NCP demand minus average demand) to NCP demand. He describes that amount as "the demand that does not occur at system peak," and he concludes that 80 percent of the GR class NCP demand occurs outside of the system peak. This calculation is not consistent with Dr. Pavlovic's definition of load diversity (or any other of which I am aware), and Dr. Pavlovic's interpretation of the value is incorrect. This value in no way represents demand that does not occur at system peak. What Dr. Pavlovic's calculation represents is simply 1.0 minus the NCP class load factor (or it would, had Dr. Pavlovic used the correct NCP demands). Thus, the value calculated for the GR class is the highest of that for any class, simply because it has the lowest load factor. In fact, all of the Rate GR (and Rates GC, L, MV-F and TS-F) NCP peak demand occurs at the system coincident peak.

Thus, while I do not object to Dr. Pavlovic's use of the A&E allocator because it is consistent with a Commission decision for PECO Gas from thirteen months ago, I disagree that the A&E method is justified by any load diversity analysis presented by PECO Gas.

Q. Please comment on Witness Sakaya's analysis.

A. Witness Sakaya proposes that a 50/50 P&A method be applied to mains costs in this proceeding, because (a) "[t]he peak day also includes supplying an average level of gas," and (b) "the Commission has consistently accepted the methodology where 50% of the original cost of mains is allocated on peak demand, and 50% . . . allocated on the average usage in past cases." Witness Sakaya cites specifically to the Columbia Gas case at Docket No. R-2020-3018835.

[4] Exhibit JD-6, page 5.

As a technical matter, Witness Sakaya begins his analysis with an incorrect premise, namely that " . . . the excess demand and the peak demand factors are often similar . . ." I respectfully disagree, particularly where class load factors vary considerably among rate classes. For a residential class with a 20 percent load factor, the excess demand is 80 percent of the peak demand. For an industrial class with a 75 percent load factor, the excess demand is only 25 percent of the peak demand. For a 100 percent load factor customer, excess demand is zero. Thus, as Witness Sakaya's data show, the excess demand allocator assigns considerably higher costs to low load factor classes than does the peak demand allocator.

As a matter of Commission precedent, I am surprised by Witness Sakaya's reliance on the Commission's Columbia Gas decision.[5] As detailed in my direct testimony, the Commission expressly rejected the 50/50 P&A proposal put forward by OCA Witness Watkins in the most recent PECO Gas base rates case, which is surely more relevant than the Columbia Gas matter. Moreover, in that case, the Commission was well-aware of its approval of the P&A method in Columbia Gas, but declined to accept it for PECO Gas, citing to the purported double-counting of average demand in the P&A allocator.[6] The Commission also generally indicated that mains cost allocation methods for natural gas distribution companies ("NGDCs") would be made on a case-by-case basis, ruling:

> Regarding the OSBA's request that the Commission affirm an ACCOSS methodology as the standard for future NGDC proceedings, as well as its selection criteria for ACCOSSs, we find that development of a regulation for determining the allocation of mains costs distribution is inappropriate at this current procedural stage of the case. We agree with PAIEUG that the inherent distinctions between utilities and rate cases may result in different methodologies to be reasonable for different reasons. In other words,

[5] Witness Sakaya's claim that the Commission has consistently approved the P&A method for NGDC mains allocation is also incorrect. As detailed in my direct testimony, the Commission explicitly approve A&E methods for the Philadelphia Gas Works ("PGW") and PPL Gas Utilities Corporation. I note that Commission approval at PGW was based on the recommendations of the Commission's Office of Trial Staff ("OTS") witness Mr. Joseph Kubas.

[6] Opinion and Order, Pennsylvania Public Utility Commission, Docket No,. R-2020-3018929, Order entered June 22, 2021, at 229-230. Note that in the Columbia matter, no party advanced an A&E methodology, and thus A&E was not explicitly rejected in that case.

> the best-suited ACCOSS may depend on the circumstances of the situation on a case-by-case basis.[7]

Thus, not only did the Commission explicitly reject Witness Sakaya's proposed methodology in the last PECO Gas case, it appears to have rejected reliance on the Columbia case or decisions for other NGDCs for establishing the appropriate cost allocation method in this proceeding.

Q. If the Commission reaches a different decision in this proceeding and accepts the P&A approach, does Witness Sakaya's quantitative analysis reasonably reflect the implications of that method?

A. No, it does not. Witness Sakaya adjusts the Company's COSS for the direct allocation of mains gross plant, accumulated depreciation. and depreciation expense. However, Witness Sakaya's adjustments fail to recognize that changing the allocation of mains costs also affects the allocation of various O&M costs (notably accounts 874 and 887) in the COSS, as well as a variety of general plant, labor and administrative overhead expenses. As such, Witness Sakaya's summary table understates the impact of a change to a P&A methodology. I developed a P&A version of my COSS model, which is provided in RDK WP1R.[8] Class rates of return at present rates under Witness Sakaya's analysis and my analysis are shown in Table RDK-1R below.

---

[7] *Id.*, at 230-231.

[8] As a technical matter, Witness Sakaya does not actually use a 50/50 peak/average method. His measure of peak demand is neither CP nor NCP but is the PECO Gas A&E allocator. However, the difference between the A&E allocator and the NCP allocator is quite small. In RDK WP1R, I use a 50/50 weighting of average demand and NCP demand, which I believe was Witness Sakaya's intent. Consistent with Witness Sakaya's approach, I include PECO's arbitrary values for the interruptible classes' NCP.

Table RDK-1R Implications of P&A Cost Allocation Method Class Rates of Return at PECO Gas Proposed Rates			
	PECO Gas A&E	**I&E Partial P&A**	**Full P&A**
GR	7.6%	8.0%	8.3%
GC	7.6%	7.9%	8.0%
L	20.3%	16.1%	18.5%
MV-F	7.6%	3.1%	0.6%
MV-I	13.9%	9.1%	7.9%
IS	9.3%	2.4%	0.0%
TCS	33.7%	12.7%	12.9%
TS-F	7.8%	5.6%	4.5%
TS-I	10.1%	3.5%	0.9%
Total	**7.7%**	**7.7%**	**7.7%**
Sources: RDK WP1, RDK WP1R, I&E Exhibit No. 3, S1, P5.			

Q. Turning to the issue of the peak demand value for the TS-F class, please summarize Witness LaConte's position regarding that value.

A. Consistent its approach with the last base rates proceeding, PECO Gas uses 69,000 mcf per day as the NCP demand for the TS-F class in developing its A&E demand allocation factor.[9] PECO Gas reports that this value is based on its TCQ contract demand value for the customers in that class. As I indicated in my direct testimony, TS-F customers appear to have exhibited both higher TCQ values than those used by PECO Gas, and many TS-F customers have consistently exceeded their contract demand values without apparent penalty.

Witness LaConte argues that (a) peak demands for the "sales customers" are CP demands, (b) peak demands for the TS-F class are based on NCP "TCQ" contract demands, and (c)

[9] Witness LaConte did not contest the 68,000 mcf per day TS-F demand factor in direct, rebuttal or surrebuttal testimony filed in the last PECO Gas base rates proceeding.

actual TS-F peak demand has not exceeded 55,779 mcf per day over the past five years, which is below the 69,000 mcf per day TCQ demand.

Witness LaConte therefore uses the 55,779 mcf per day value as the peak demand measure in the alternative COSS.

Q. Do you agree with this modification?

A. I do not, for the following reasons:

- As detailed in the AGA's Gas Rate Fundamentals, the A&E allocator is designed to rely on class NCP and not on class CP.[10] Witness LaConte is therefore incorrect that CP demand is appropriate for developing the Rate TS-F A&E demand allocator.

- The peak demands used for the GR and GC classes in the PECO Gas COSS are based on extreme weather conditions, and do not reflect any actual coincident peak demands. Because the demands for these classes are based on extreme design weather conditions, the peak demands for all customers occur at the same time, and there is no diversity and CP equals NCP. Thus, the PECO Gas approach uses NCP demands for both the GR and GC classes with smaller customers, as well as for the larger customers in the TS-F class.

- While CP demands may be causally relevant for electric generation and gas transmission assets, they are much less relevant for a gas distribution system, where many of the gas mains serve a relatively small number of customers. Mains serving residential neighborhoods and larger industrial customers must be sized to meet the specific demands of customers in the neighborhood, or the individual demand of the individual large industrial customer, and not diversified CP demands. As such, NCP is often a more appropriate measure of peak demand for gas distribution mains than CP.

- Cost causation requires that costs be allocated based on the factor that causes costs to be incurred. While I do not have a specific reference for the PECO Gas system planning

[10] Gas Rate Fundamentals, Fourth Edition, American Gas Association, © 1987, at 143-145.

procedures, I would be very surprised if PECO Gas does not plan its gas distribution based on the need to provide capacity to meet the individual contract demands of its larger customers.

- In my experience, some NGDCs use contract demands for deriving peak demand in cost allocation analyses for larger customers (e.g., UGI Gas), while others do not. From my experience, the PECO Gas approach is within normal practice.

- Even if the Commission determines that TCQ is inappropriate, Witness LaConte's proposal to rely on actual peak TS-F demands is not reasonable. As Witness LaConte acknowledges, the peak demands for the GR and GC classes are based on extrapolations of demand to extreme weather conditions and not actual peak demands. As my regression analysis in RDK WP2 demonstrates, TS-F demands also have a significant weather component, and therefore the TS-F demand under design conditions would exceed actual historical peak demands. Thus, if an alternative approach for deriving TS-F peak demands is needed, it should rely on the same approach as that applied to the smaller customer classes, namely the derivation of design demands based on extreme weather conditions. As I demonstrate in RDK WP2, my regression analysis of monthly TS-F loads suggests that the 69,000 mcf per day value is not obviously unreasonable.

- As further evidence of the inconsistency for using actual peak demands for the TS-F class, consider Witness LaConte's Table 1, where the highest *actual* TS-F load was 55,779 mcf/day in 2018, or about 87 percent of the total TCQ demand for that year. In contrast, the maximum actual Rate GR peak demands (from Exhibit BSL-10) was 467,922 mcf per day in 2018, compared to the design day GR demand used for cost allocation in this proceeding of 580,741 mcf per day, a ratio of under 81 percent. In effect, the PECO Gas COSS marks up the Rate GR actual day demand to design day demand far more than it implicitly marks up the TS-F demand. It is not reasonable for Witness LaConte to implicitly assume that PECO Gas plans its gas distribution system based on a historical actual value for the TS-F class, while using extreme weather design day demands for its GR and GC classes.

I therefore conclude that Witness LaConte's proposal to adjust the TS-F peak day demand down to an actual historical value is inconsistent with both cost causation and with Witness LaConte's use of design day weather conditions for deriving peak demands for the other firm service rate classes.

Q. Turning to the last cost allocation matter, at page 11, I&E Witness Sakaya recommends that PECO Gas separate "flex" rate NGS customers for cost allocation in its next base rates proceeding. Do you agree?

A. I do. As I indicated in my direct testimony, the objective of providing discounted rates to customers with competitive options is to retain revenues to the benefit of all customers, even if doing so requires a discount from regular rates. If the flex rate customers are included in only one or two rate classes, the burden associated with the shortfall is not equitably shared among the customers who benefit. In this case, separate allocation to the flex rate customers has merit because, as I understand it, the direct-assigned mains costs are associated with flex rate customers. Separately evaluating both the revenues and costs for the NGS customers would allow the Commission to determine the magnitude of any embedded cost under-recovery from the flex rate customers, and then share that burden reasonably. As I indicated in my direct testimony, Columbia Gas has adopted this approach.[11]

3. <u>Revenue Allocation</u>

Q. Please summarize the positions of the intervenor parties regarding revenue allocation.

A. A tabular comparison of the revenue allocation proposals of the various parties is shown in the RevAllocComp tab of RDK WP1R. A brief review of the positions of the parties is as follows:

OCA Witness Pavlovic recommends a modestly lower increase for the GR class and modestly higher increases for the GC and MV-F classes compared to the Company's proposal, ostensibly on the grounds that moving rates into line with allocated costs is inherently inequitable, and that progress toward cost-based rates should be limited to about half the current revenue-cost differences.

[11] PECO-OSBA-I-3.

PAIEUG Witness LaConte proposes a materially lower rate increase for the TS-F class to reflect the proposed change to the Rate TS-F demand allocator, with offsetting higher increases for the GR, GC and MV-F rate classes.

I&E Witness Sakaya recommends assigning a large increase for the TS-I rate class, as well as applying larger increases for the TS-F and MV-F rate classes, to reflect the results of using the P&A cost allocation method for mains. Witness Sakaya also recommends that any scaleback to the overall revenue requirement be applied only to the GR and GC rate classes, and not to the other rate classes.

I accepted the Company's proposal, subject to clarification regarding a number of apparent errors in the Company's COSS.

Q. Please address Witness Pavlovic's approach.

A. I respectfully disagree with Dr. Pavlovic's conclusion that the Company's proposal is inequitable, based on the results of its COSS (which Dr. Pavlovic accepts). As I explained in my direct testimony, the Company proposes to move revenues for all classes into line with allocated cost, subject to the restrictions that no rate decreases be granted and that market-based rates are unchanged. There is no obvious reason to limit progress toward cost-based rates for certain classes, unless doing so would require unreasonable increases for other rate classes. In this case, Dr. Pavlovic does not explain why the Company's proposed increase for the GR class is unreasonable (at 23.0 percent compared to a system average increase of 20.1 percent), nor why an alternative increase of 21.5 percent for the GR class would justify Dr. Pavlovic's proposal that small business customers continue to pay rates in excess of allocated cost. As parties to these proceedings are well-aware, allocated cost is the polestar criterion for revenue allocation in Pennsylvania. As such, Dr. Pavlovic's aversion to cost-based rates is perplexing.

Second, Dr. Pavlovic's recommended revenue allocation does not achieve the goals stated, namely moving rates halfway into line with allocated cost. As I explained in my direct testimony, the indexed rate of return metric upon which Dr. Pavlovic apparently relies will tend to overstate actual progress toward cost-based rates. Using Dr. Pavlovic's proposed increase and my replication of the Company's COSS, I calculate that the progress toward

cost-based rates for the major classes based on the unbiased revenue-cost ratio metric is the following:

Class	Current →	Proposed	(Progress)
GR:	97.3% →	98.5%	(44% progress)
GC:	104.9% →	102.9%	(40% progress)
MV-F	106.0% →	102.8%	(54% progress)
TS-F	98.3% →	100.5%	(129% progress)
TS-I	139.7% →	115.6%	(61% progress)

In effect, Dr. Pavlovic appears to have inequitably targeted the Rate GC class for the least progress toward cost-based rates.

Q. Please comment on Witness LaConte's proposed revenue allocation.

A. Witness LaConte's proposed revenue allocation is consistent with the results of the PAIEUG COSS. For the reasons detailed above, I do not agree with the proposed change to the Rate TS-F demand allocator. For that reason, I do not believe that Witness LaConte's revenue allocation proposal should be adopted.

Q. Please comment Witness Sakaya's proposed revenue allocation.

A. As I indicated earlier, I disagree that the P&A mains cost allocation approach advocated by Witness Sakaya is consistent with Commission precedent, and I conclude that Witness Sakaya's analysis does not fully reflect the implications of adopting a P&A mains cost allocation approach in this proceeding. I therefore disagree with the cost basis for Witness Sakaya's proposal.

If the Commission reverses its prior decision and adopts the P&A method for mains allocation, my RDK WP1R shows the implications of Witness Sakaya's revenue allocation at the full revenue requirement. As shown, that approach would result in the revenue-cost ratio for the GR class moving away from allocated cost (100.9% to 102.8%), the GC class

moving mostly into line with allocated cost (107.5% to 101.5%), and the TS-F and TS-I rate classes making little or no progress toward cost-based rates. Witness Sakaya's scaleback approach would generally serve to address those issues if there is a material reduction in the overall increase, although it is difficult to analyze without knowing the magnitude of the scaleback. Based on my analysis in RDK WP1R, however, I conclude that Witness Sakaya's revenue allocation approach does not produce unreasonable results for the Rate GC class.

Q. Overall, what are the implications of the various proposals for revenue allocation for small business customers in Rate GC?

A. Overall, despite a variety of alternative costing issues, the parties generally agree that revenues should be moved more into line with allocated cost, and that the Rate GC class should be assigned a rate increase that is below the system average increase of 20.1 percent. The range of proposals involves increases for Rate GC from 13.3 to 17.8 percent, with I&E at the lower end (due to higher increases for TS-F and TS-I), and OCA at the high end (due to an apparent aversion to moving rates into line with allocated cost).

4. <u>Corrections to Direct Testimony</u>

Q. Please specify the errors in your direct testimony that were identified in the discovery process.

A. In my direct testimony, I cited to and provided various workpapers that evaluated the relative load factor for larger and smaller customers within the TS-F rate class, for the purpose of evaluating the large rate differentials between those two customer sub-classes. In reviewing those workpapers (retained from the Company's last base rates case), the Company correctly observed that I had inadvertently excluded many customers from the analysis. In PECO-OSBA-IV-1, I corrected and updated that analysis. The upshot of the new analysis is that the values reported in OSBA Statement No. 1 page 35 line 23 changed. However, these changes were not material to my conclusions. The updated analysis in my response to PECO-OSBA-IV-1 is included in Exhibit RDK-2R.

In my direct testimony certain values in Tables RDK-3, RDK-4 and RDK-6 were mis-transcribed from my workpapers to my direct testimony. Corrected versions of these tables

are detailed in my responses to PAIEUG-OSBA-I-3, PAIEUG-OSBA-I-4 and PECO-OSBA-III-2. These IR responses are also included in Exhibit RDK-2R.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT RDK-1R

ELECTRONIC WORKPAPERS OF ROBERT D. KNECHT

RDK WP1R: PECO Gas COSS with P&A Mains Allocation

Electronic workpapers will be delivered via email simultaneous to email distribution of Rebuttal Testimony.

EXHIBIT RDK-2R

REFERENCED INTERROGATORY RESPONSES

PAIEUG-OSBA-I-3

PAIEUG-OSBA-I-4

PECO-OSBA-I-3

PECO-OSBA-III-2

PECO-OSBA-IV-1 (with attached WP4 Corrected)

Electronic workpapers will be delivered via email simultaneous to email distribution of Rebuttal Testimony.

PAIEUG-OSBA-I-3

Referring to Table RDK-4, please confirm that the proposed volumetric charge for TS-F customers with volumes above 18,000 Mcf is $1.2696/Mcf as shown in RDK-WP-1, rather than what is shown on page 36 of the testimony PDF.

Response:

Confirmed. The original Table RDK-4 incorrectly reported proposed volumetric charge values as those proposed by PECO, rather than my proposed values form the workpapers, and it reversed the current rates customer charges. In reviewing the rate design tables, I identified other errors of transcription from workpapers to testimony. (See also PECO-OSBA-III-2.) Corrected versions of Tables RDK-3, RDK-4 and RDK-6 are provided below, with the modified entries shaded. I regret any confusion caused by these errors.

Table RDK-3 CORRECTED **PECO Gas Rate TS-F Rate Design Proposal**			
	Under 18 mmcf	**Over 18 mmcf**	**Differential**
Current Rates			
Customer Charge ($/mo.)	$184.00	$221.07	-16.8%
Volumetric Charge ($/mcf)	$1.9416	$0.9267	109.5%
Average Charge* ($/mcf)	$2.27	$0.98	130.2%
Proposed Rates			
Customer Charge ($/mo.)	$278.66	$334.80	-16.8%
Volumetric Charge ($/mcf)	$2.5356	$1.2102	109.5%
Average Charge* ($/mcf)	$2.96	$1.27	133.3%
Percent Increase			
Customer Charge ($/mo.)	51.4%	51.4%	--
Volumetric Charge ($/mcf)	30.6%	30.6%	--
Average Charge* ($/mcf)	30.5%	28.8%	--
* Current rate tariff charges include the effect of the DSIC. Averages exclude negotiated rate customers and PGC-related charges. Sources: RDK WP1, "RevPrf" tab.			

Table RDK-4 CORRECTED RDK Alternative Rate TS-F Rate Design Proposal			
	Under 18 mmcf	**Over 18 mmcf**	**Differential**
Current Rates			
Customer Charge ($/mo.)	$184.00	$221.07	-32.1%
Volumetric Charge ($/mcf)	$1.9416	$0.9267	109.5%
Average Charge* ($/mcf)	$2.27	$0.98	130.2%
Proposed Rates			
Customer Charge ($/mo.)	$227.26	$334.80	-16.8%
Volumetric Charge ($/mcf)	$2.3832	$1.2696	87.7%
Average Charge* ($/mcf)	$2.73	$1.33	105.5%
Percent Increase			
Customer Charge ($/mo.)	23.5%	51.4%	--
Volumetric Charge ($/mcf)	22.7%	37.0%	--
Average Charge* ($/mcf)	20.4%	34.8%	--
* Current rate tariff charges include the effect of the DSIC. Averages exclude negotiated rate customers and PGC-related charges. Sources: RDK WP1, "RevPrf RDK" tab.			

Table RDK-6 CORRECTED RDK Alternative Rate TS-I Rate Design Proposal			
	Under 18 mmcf	**Over 18 mmcf**	**Differential**
Current Rates			
Customer Charge ($/mo.)	$233.00	$277.21	-15.9%
Volumetric Charge ($/mcf)	$1.5931	$0.8484	87.8%
Average Charge* ($/mcf)	$1.98	$0.90	130.2%
Proposed Rates			
Customer Charge ($/mo.)	$233.00	$379.36	-38.6%
Volumetric Charge ($/mcf)	$1.5931	$0.9344	70.5%
Average Charge* ($/mcf)	$1.98	$1.00	97.6%
Percent Increase			
Customer Charge ($/mo.)	0.0%	36.8%	--
Volumetric Charge ($/mcf)	0.0%	10.1%	--
Average Charge* ($/mcf)	0.0%	11.6%	--
* Current rate tariff charges include the effect of the DSIC. Averages excludes negotiated rate customers; excludes PGC and backup related charges. Sources: RDK WP1, "RevPrf" tab.			

PAIEUG-OSBA-I-4

Referring to Table RDK-4 please confirm that the proposed volumetric charge for TS-F customers with volumes at or below 18,000 Mcf is 2.3832/Mcf as shown in RDK-WP-1, rather than what is shown on page 36 of the testimony PDF.

Response:

Confirmed. Please see response to PAIEUG-OSBA-I-3.

PECO-OSBA-I-3

Refer to OSBA Statement No. 1, p. 27, line 22. Mr. Knecht states, "Columbia Gas has adopted this approach for its flex rate customers." Please provide the docket number for the order approving the rate referenced.

Response:

Separate allocation of flex rate customer costs was agreed to as part of the settlement of the Columbia Gas base rates case at Docket Nos. R-2018-2647577, et al. The settlement agreement indicated, *"In its next base rate proceeding, the Company agrees to segregate flex rate customers into a separate category in each of its filed cost allocation studies. The Company shall not be required, however, to allocate the revenue shortfall from the flex rate customer class to the regular rate classes as part of its cost allocation analysis."*

PECO-OSBA-III-2

Refer to OSBA Statement No. 1, page 34, line 13 (Table RDK-3) and page 36, line 10 (Table RDK-4). Please explain the basis for Mr. Knecht's increase in the average charge for customers with over 18 mmcf usage from the amount shown in Table RDK-3 to the amount shown in Table RDK-4 when the customer charge and volumetric charge appear to be the same. Please include references to Mr. Knecht's supporting workpapers for the calculations.

Response:

The customer charges were mis-reported (reversed) in Table RDK-3, and my proposed charges for Rate TS-F were incorrectly reported in Table RDK-4. In reviewing the rate design tables, I note also that Table RDK-6 has incorrect percentage change values. The correct values are shown in RDK WP1 (worksheet "RevPrf RDK"). Corrected versions of Tables RDK-3, RDK-4 and RDK-6 are provided below, with the modified entries shaded. I regret any confusion caused by these errors.

Table RDK-3 CORRECTED **PECO Gas Rate TS-F Rate Design Proposal**			
	Under 18 mmcf	**Over 18 mmcf**	**Differential**
Current Rates			
Customer Charge ($/mo.)	$184.00	$221.07	-16.8%
Volumetric Charge ($/mcf)	$1.9416	$0.9267	109.5%
Average Charge* ($/mcf)	$2.27	$0.98	130.2%
Proposed Rates			
Customer Charge ($/mo.)	$278.66	$334.80	-16.8%
Volumetric Charge ($/mcf)	$2.5356	$1.2102	109.5%
Average Charge* ($/mcf)	$2.96	$1.27	133.3%
Percent Increase			
Customer Charge ($/mo.)	51.4%	51.4%	--
Volumetric Charge ($/mcf)	30.6%	30.6%	--
Average Charge* ($/mcf)	30.5%	28.8%	--
* Current rate tariff charges include the effect of the DSIC. Averages exclude negotiated rate customers and PGC-related charges. Sources: RDK WP1, "RevPrf" tab.			

Table RDK-4 CORRECTED RDK Alternative Rate TS-F Rate Design Proposal			
	Under 18 mmcf	**Over 18 mmcf**	**Differential**
Current Rates			
Customer Charge ($/mo.)	$184.00	$221.07	-32.1%
Volumetric Charge ($/mcf)	$1.9416	$0.9267	109.5%
Average Charge* ($/mcf)	$2.27	$0.98	130.2%
Proposed Rates			
Customer Charge ($/mo.)	$227.26	$334.80	-16.8%
Volumetric Charge ($/mcf)	$2.3832	$1.2696	87.7%
Average Charge* ($/mcf)	$2.73	$1.33	105.5%
Percent Increase			
Customer Charge ($/mo.)	23.5%	51.4%	--
Volumetric Charge ($/mcf)	22.7%	37.0%	--
Average Charge* ($/mcf)	20.4%	34.8%	--
* Current rate tariff charges include the effect of the DSIC. Averages exclude negotiated rate customers and PGC-related charges. Sources: RDK WP1, "RevPrf RDK" tab.			

Table RDK-6 CORRECTED RDK Alternative Rate TS-I Rate Design Proposal			
	Under 18 mmcf	**Over 18 mmcf**	**Differential**
Current Rates			
Customer Charge ($/mo.)	$233.00	$277.21	-15.9%
Volumetric Charge ($/mcf)	$1.5931	$0.8484	87.8%
Average Charge* ($/mcf)	$1.98	$0.90	130.2%
Proposed Rates			
Customer Charge ($/mo.)	$233.00	$379.36	-38.6%
Volumetric Charge ($/mcf)	$1.5931	$0.9344	70.5%
Average Charge* ($/mcf)	$1.98	$1.00	97.6%
Percent Increase			
Customer Charge ($/mo.)	0.0%	36.8%	--
Volumetric Charge ($/mcf)	0.0%	10.1%	--
Average Charge* ($/mcf)	0.0%	11.6%	--
* Current rate tariff charges include the effect of the DSIC. Averages excludes negotiated rate customers; excludes PGC and backup related charges. Sources: RDK WP1, "RevPrf" tab.			

PECO Energy Company

Base Rates Case, FPFTY Ending 31 December 2023

Docket No. R-2022-3031113

OSBA Responses to PECO Interrogatories Set IV

PECO-OSBA-IV-1

PECO-OSBA-IV-1. Refer to OSBA Statement No. 1, page 35, line 23, where Mr. Knecht references "ratio (1.25 to 1.53)," a calculation derived from Mr. Knecht's workpaper RDK WP4. Please provide an explanation as to why Mr. Knecht's calculations only included data starting at excel line 291 and why the calculations did not include data from excel lines 5 to 290.

Response:

RDK WP4 in this proceeding is a copy of my RDK WP4 from the Company's last base rates proceeding. The spreadsheet formulae referenced in the interrogatory appears to contain an inadvertent error, in both the workpaper from the last case and the current filing. Attached is a corrected version of RDK WP4. As shown in that workpaper, simply correcting the formula to include all TSF customers changes the quoted range from "1.25 to 1.53" to "1.33 to 2.18."

This range represents the ratio of large TS-F customer (over 18mmcf/year) load factor to smaller TS-F customer (under 18mmcf/year) load factor, evaluated using a simple average (the lower end of the range) and a weighted average (the upper end). In reviewing the updated calculation, I observe that such a substantial difference between the simple average (1.33) and the weighted average (2.18) often implies that there are outliers in the data that are skewing the result. I therefore reviewed the data more carefully, and I identified (a) a small set of TS-F customers with extremely low load factors, which may result from data errors or a from a shortened period

of service (less than a full year), and (b) a small set of customers with load factors over 100%, which may result from data errors or extraordinary circumstances. I therefore recalculated the averages excluding all customers with load factors below 5% and above 100%. This analysis eliminated only 12 of 489 TS-F customers, and it resulted in a range of load factor ratios of 1.36 (simple average) to 1.56 (weighted average). These calculations are also shown in the attached corrected workpaper.

I conclude that excluding the outliers is a superior approach for rate design analysis, because rate design should be based on the load patterns of the vast majority of customers, and not skewed by an extraordinary few. Moreover, correcting the cited range in my direct testimony from "1.25 to 1.53" to "1.36 to 1.56" has no impact on the conclusions or recommendations in that testimony regarding the appropriate volumetric charge differential for Rate TS-F.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3031113**
PECO Energy Company (Gas Division)	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Rebuttal Testimony labelled OSBA Statement No. 1-R and associated Exhibit RDK-1R are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: July 21, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3031113**
	:	
PECO Energy Company-Gas Division	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

Laura J. Antinucci, Esquire
Barrett C. Sheridan, Esquire
Mackenzie C. Battle, Esquire
Darryl A. Lawrence, Esquire
Office of Consumer Advocate
555 Walnut Street, 5th Floor
Harrisburg, PA 17101
lantinucci@paoca.org
bsheridan@paoca.org
mbattle@paoca.org
Darryllwarence@paoca.org
(Counsel for OCA)

Karl R. Pavlovic
PCMG & Associates LLC
22 Brookes Avenue
Gaithersburg, MD 20877
OCAPECOGAS2022@paoca.org

Anthony E. Gay, Esq.
Jack R. Garfinkle, Esq.
Brandon J. Pierce, Esq.
Caroline S. Choi, Esq.
PECO Energy Company
2301 Market Street
P.O. Box 8699
Philadelphia, PA 19101
anthony.gay@exeloncorp.com
jack.garfinkle@exeloncorp.com
brandon.pierce@exeloncorp.com
caroline.choi@exeloncorp.com

Scott B. Granger, Esquire
Bureau of Investigation & Enforcement
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
sgranger@pa.gov

Byron Goldstein
2365 Geneva Avenue
Glenside, PA 19038
BGoldmarketing@RCN.com

Lauren N. Berman, Esq.
Ria M. Pereira, Esq.
John W. Sweet, Esq.
Elizabeth R. Marx, Esq.
Pennsylvania Utility Law Project
118 Locust Street
Harrisburg, PA 17101
pulp@pautilitylawproject.org

Kenneth M. Kulak, Esq.
Mark A. Lazaroff, Esq.
Brooke E. McGlinn, Esq.
Catherine G. Vasudevan, Esq.
Morgan, Lewis & Bockius LLP
1701 Market Street
Philadelphia, PA 19103
ken.kulak@morganlewis.com
mark.lazaroff@morganlewis.com
brooke.mcglinn@morganlewis.com
catherine.vasudevan@morganlewis.com

Roger D. Colton
Fisher Sheehan & Colton
34 Warwick Road
Belmont, MA 02478
OCAPECOGAS2022@paoca.org
Consultant for OCA

Richard G. Webster, Jr., VP
Regulatory Policy & Strategy
PECO Energy Company
2301 Market Street - S15
Philadelphia, PA 19103
dick.webster@exeloncorp.com

Charis Mincavage, Esquire
Adeolu A. Bakare, Esquire
Diamond U. Wade, Esquire
McNees Wallace & Nurick LLC
100 Pine Street
P. O. Box 1166
Harrisburg, PA 17108-1166
cmincavage@mcneeslaw.com
abakare@mcneeslaw.com
dwade@mcneeslaw.com

The Honorable F. Joseph Brady
Administrative Law Judge
Pennsylvana Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107
fbrady@pa.gov

DATE: July 22, 2022

/s/ Steven C. Gray

_____
Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney I.D. No. 77538

COMMONWEALTH OF PENNSYLVANIA

August 4, 2022

The Honorable F. Joseph Brady
Administrative Law Judge
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107

Re: Pennsylvania Public Utility Commission v. PECO Energy Company – Gas Division / Docket No. R-2022-3031113

Dear Judge Brady:

Enclosed please find the Surrebuttal Testimony and Exhibits of Robert D. Knecht, , labeled OSBA Statement No. 1-S, on behalf of the Office of Small Business Advocate ("OSBA"), in the above-captioned proceeding.

As evidenced by the enclosed Certificate of Service, all known parties will be served, as indicated.

If you have any questions, please do not hesitate to contact me.

Sincerely,

/s/ Steven C. Gray

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney ID No. 77538

Enclosures
cc: **PA PUC Secretary Rosemary Chiavetta (Cover Letter & Certificate of Service only)**
Robert D. Knecht
Parties of Record

OSBA Statement No. 1-S

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3031113**
PECO Energy Company (Gas Division)	:	

Surrebuttal Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design

Date Served: August 4, 2022

Date Submitted for the Record: August 11, 2022

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. Introduction and Overview

Q. Please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I submitted direct testimony, rebuttal testimony and associated exhibits earlier in this proceeding, and my qualifications were detailed therein.

Q. What is the purpose of this surrebuttal testimony?

A. This surrebuttal testimony responds to the following witnesses/topics:

PECO Energy Company (Gas Division) ("PECO Gas" or "the Company") witness Jiang Ding on matters of cost allocation;

PECO Gas witness Joseph A. Bisti on matters of revenue allocation and rate design;

Philadelphia Area Industrial Energy Users Group ("PAIEUG") witness Billie S. LaConte, on matters of cost allocation, revenue allocation and rate design.

Issues of cost allocation, revenue allocation and rate design are addressed in Sections 2, 3 and 4 respectively.

Acronyms and initialisms in this testimony are defined in my earlier testimony.

2. Cost Allocation

Q. In this proceeding, you have (again) recommended that the Company segregate the TS-F and TS-I rate classes into customers above and below the 18 mmcf per year demarcation point used by PECO Gas for its tariff charges. What is the Company's response?

A. Witness Ding does not acknowledge that it has entirely separate rates in the TS-F and TS-I rate classes for customers whose consumption is below 18 mmcf per year and for customers whose consumption exceeds 18 mmcf per year. Witness Ding does not acknowledge that setting entirely separate rates for these subgroups of customers is the Company's choice and not mine or OSBA's. Furthermore, the Company has thus far declined to provide any cost

analysis justifying the need for entirely separate rates for the two customer groups within each rate class, and it has declined to provide the information necessary for parties to conduct such analysis independently. The Company appears to rely primarily on the "we've always done it that way" defense.

Beyond reliance on the status quo, Witness Ding's only defense of the existing method is that the cost to serve smaller customers within the class could vary for many different reasons, such as some customers may take service at a lower system pressure system.

I agree, of course. In fact, I have advocated that gas distribution utilities begin modifying their mains cost allocation analyses to reflect the specific mains used to serve individual customers, both large and small.[1] The Company has not undertaken any such analysis, save for the limited direct assignment of costs to a very small number of customers.

Unfortunately, Witness Ding reaches the opposite conclusion, and asserts that because costs can vary for many reasons, PECO Gas should allocate the costs to large heterogeneous rate classes based only on classwide average-and-excess ("A&E") demand. This method implies that the Company must either set the same rates for all customers within the class, or set differentiated rates for customers within those classes based on zero cost information.

I respectfully disagree. If the Company wishes to retain entirely separate rates for TS-F and TS-I customers depending on their size, it should make a reasonable effort to assess the cost of service for those separate customer groups.

I therefore retain my recommendation that, if PECO Gas wishes to continue to have entirely separate rates for sub-classes of customers within the TS-F and TS-I rate classes, it should allocate the costs separately. If Witness Ding uses that opportunity to make the analysis more detailed to better reflect actual cost causation factors such as operating pressure and length of mains, I'm all for it.

[1] OSBA Statement No. 1 at 9-10.

Q. Witness Ding also opposes the recommendation advanced by both I&E Witness Sakaya and you that PECO Gas segregate Rate NGS "flex" rate customers for cost and revenue allocation purposes. What arguments are offered?

A. Witness Ding first indicates that segregating these customers would be impractical, because customers are moving between flex and regular rate service. Witness Ding also indicates that segregation is unnecessary, because the number of flex rate customers is small and declining (from six currently to an expected four in the future). Witness Ding then appears to argue that a separate class is unnecessary because cost-based rates are not appropriate for flex rate customers.

Q. Can you respond?

A. Regarding Witness Ding's first argument, I cannot follow the logic. For this proceeding, the Company necessarily made a forecast for the fully projected future test year ("FPFTY") as to which customers were regular rate and which customers were flex rate NGS customers, to develop its revenue forecast. It therefore has a specific forecast for who the Rate NGS customers are for the FPFTY, and it can determine their loads, contract demands, meter costs, and other cost factors easily. The Company can obviously do so again in a future proceeding, for cost allocation as well as revenue purposes. Very little additional analysis would be required.

Witness Ding's second argument would be reasonable, if the Company had analyzed the magnitude of the revenue shortfall rather than the number of customers. If the Company can demonstrate that the difference between regular rate and flex rate revenues is small, I would agree that there is no need for a separate flex rate class in the COSS. If, however, there is a large dollar difference between rates and costs for these customers, a separate flex rate class is justified for cost allocation regardless of how few customers have flex rates. Witness Ding does not, however, provide that analysis.

Witness Ding's third argument misses the point. The reason to have a separate flex rate class is not to develop embedded cost-based rates for those customers. It is to determine the magnitude of the revenue shortfall relative to allocated cost from the flex rate customers, and to allocate that shortfall in some reasonable form across all rate classes. By burying the

flex rate customers in the TS-F and TS-I rate classes, the Company implicitly assigns any shortfall from those customers only to TS-F and TS-I customers.

Q. Witness Ding also indicates that your proposal would result in an excessive number of rate classes, and would require the Company to reflect confidential information in the COSS. Is that accurate?

A. No. Witness Ding incorrectly assumes that there would need to be three separate flex rate classes for the GC, TS-F and TS-I rate classes with flex rate customers. There is no reason at all to have separate flex rate classes, or to separately report the directly assigned plant. My proposal is that all flex rate customers be included in a single flex rate class, and that directly assigned plant be reported exactly as it is now.

Moreover, Witness Ding's complaint about having too many rate classes is not without irony. The Company's COSS model includes three rate classes that (a) represent only 24 customers in total, (b) account for only 0.18 percent of the system throughput and 0.03 percent of system costs, and (c) do not rely on the COSS for setting rates.[2] Thus, the Company already wastefully includes three customer classes with miniscule costs and non-cost-based rates. The Company could (and arguably should) remove the MV-I, IS and TCS rate classes from its COSS and simply allocate the base distribution revenue credit from those classes in some reasonable manner. With that change, the Company could eliminate three rate classes from the existing slate and replace them with three rate classes that would provide useful information for revenue allocation and rate design, namely an additional TS-F class, and additional TS-I class, and a flex rate class.

Q. Please turn to the issue of the allocation of service line costs. In your direct testimony, you indicated that the Company's use of a relatively short historical period for services costs (five years) limited the Company's ability to differentiate service line costs among the non-residential rate classes. Please review Witness Ding's response.

A. Witness Ding does not acknowledge that service lines represent an enormous component of the cost of service. Witness Ding does not acknowledge that using the data for the past ten

[2] PECO Gas' rates for the MV-I, IS and TCS rate classes are set based on market prices, not cost of service.

years would likely produce a materially different result for cost allocation. Witness Ding does not acknowledge that the Company's method leaves it unable to differentiate service line costs among non-residential customer classes.

Ms. Ding's defense of the Company's method is essentially "we've always done it that way." I respectfully disagree that continuing to use an inferior cost allocation method for historical consistency reasons is a reasonable approach. Rather, the Company should strive to continually improve the accuracy of the cost allocation, particularly when it involves a very large cost item. To its credit, the Company has departed from some of its traditional methods in this proceeding in order to improve cost allocation accuracy in a number of other areas (most notably the development of peak demand allocators). It should continue to work to improve costing analysis in the future for services costs.

Nevertheless, for the purposes of this proceeding, and because I do not have access to the detailed information available to the Company, I rely on the Company's method.

Q. In your direct testimony, you expressed a concern that TS-F customers appeared to exhibit maximum day demands well in excess of the TCQ contract demand used as the peak demand for cost allocation. You also expressed a concern that the Company did not explain how TCQ demands are derived. Please address the Company's response.

A. My analysis was based on my review of the maximum daily demands and TCQs provided by the Company. In response to discovery, I conducted some additional analysis of that data, which was provided in PECO-OSBA-V-1 (attached in Exhibit IEc-S2). That analysis indicated that, on average, more than one-third of the TS-F customers had maximum day demand in excess of TCQ over the past five years.

In rebuttal, Witness Ding provides additional information regarding how TCQ demands are set, including the argument that TCQ's are updated to reflect actual peak demands in the prior year. Witness Ding offers no explanation as to why a large number of TS-F customers exhibit maximum demands above TCQ. However, while I retain my concerns that the TCQ used for cost allocation appears to understate TS-F customer maximum demands, I acknowledge that my statistical analysis did not demonstrate that the TCQ was necessarily unreasonable, and I have no better basis in this proceeding for setting the TS-F design day

demand allocator. I therefore accept the Company's use of TCQ in this proceeding, to be further analyzed in future proceedings as necessary.

Q. With the Company's rebuttal, what is your overall evaluation of the Company's most recent COSS?

A. As I indicated in my direct testimony, the Company's COSS in this proceeding represents a substantial improvement over that filed in the last base rates proceeding. Moreover, the Company's rebuttal COSS appears to address the errors in its initially filed COSS that were flagged in OSBA-I-4(i) (misallocation of DSIC), OSBA-I-4(k) (improper inclusion of PGC revenues), OSBA Statement No. 1 at 24 (understatement of market-based revenues for Rates IS and TCS), and my response to PECO-OSBA-II-1 (incorrect contract demand for a direct assignment customer). In addition, the Company has modified its "current rate" revenues for certain Rate NGS customers, to reflect my concerns that the rate discounts were not adequately justified by competitive conditions. I acknowledge that the Company has carefully considered my cost allocation recommendations and has made reasonable efforts to address many of them.

I retain my recommendations that the Company modify its COSS to separately allocate costs for the two groups of TS-F and TS-I customers, and I retain my recommendation that the Company establish a separate rate class of flex rate (Rate NGS) customers unless it demonstrates that the revenue shortfall is minimal. I also conclude that the Company should look to improve its cost allocation method for services costs, particularly within the non-residential customer group. However, these are enhancements that can be deferred until the next base rates case. I therefore rely on the Company's rebuttal COSS for revenue allocation and rate design

3. <u>Revenue Allocation</u>

Q. Has the Company revised its revenue allocation proposal in rebuttal?

A. In rebuttal, the Company has retained its basic philosophy for revenue allocation, updated modestly to reflect changes in current rate revenues and the COSS results. As I explained in my direct testimony, that philosophy is generally to move rates into line with allocated cost, subject to the constraints that no class be assigned a decrease and no class be assigned

1 an increase more than 2.0 times the system average. The Company's original and rebuttal
2 revenue allocation proposals are shown in Table IEc-S1 below.

Table RDK-S1 PECO Gas Revenue Allocation Proposals ($000)				
	Original	**Percent Increase**	**Rebuttal**	**Percent Increase**
GR	61,818.3	23.0%	61,264.9	22.8%
GC	13,764.2	13.8%	14,515.0	14.5%
L	0.0	0.0%	0.0	0.0%
MV-F	49.6	10.7%	53.8	11.6%
MV-I	0.0	0.0%	0.0	0.0%
IS	(0.0)	0.0%	(0.0)	0.0%
TCS	(0.0)	0.0%	0.0	0.0%
TS-F	3,652.3	23.5%	3,447.7	22.2%
TS-I	(0.0)	0.0%	(0.0)	0.0%
Total	**79,284.5**	**20.1%**	**79,281.4**	**20.1%**
Sources: RDK WP1, RDK WP1R, I&E Exhibit No. 3, S1, P5.				

3 **Q. Is the Company's proposal reasonable?**
4 A. I conclude that the Company's proposal is consistent both with the results of its rebuttal
5 COSS and with the principles of rate gradualism. Table RDK-S2 below reports revenue-
6 cost ratios at present and proposed rates for those rate classes subject to cost-based rates.
7 (MV-I, IS and TCS are excluded because rates are market-based.)

Table RDK-SS Review of PECO Gas Revenue Allocation Revenue-Cost Ratios		
	Current Rates	**Proposed Rates**
GR	97.4%	99.6%
GC	104.5%	99.8%
L	208.8%	172.9%
MV-F	105.2%	99.7%
TS-F	98.6%	100.4%
TS-I	135.4%	112.1%
Total	**100.0%**	**100.0%**
Sources: RDK WPS1.		

As shown, the Company's revenue allocation proposal either moves rates nearly into line with allocated costs (Rates GR, GC, MV-F and TS-F), or makes material progress toward cost-based rates by applying a zero rate increase (Rates L and TS-I). Moreover, as shown in Table RDK-S1, the largest rate increase for any class is 22.8 percent, only modestly above the system average increase of 20.1 percent. I therefore conclude that the Company's rebuttal revenue allocation is reasonable for the purposes of this proceeding.

4. <u>Rate Design</u>

Q. Let's start with Rate GC. In your direct testimony, you indicated that the customer-related cost for the many small customers in Rate GC was no different than the customer cost for the average residential customer, and therefore the cost basis for the Rate GC customer charge should be the residential customer cost in your COSS. Please address the Company's response.

A. Witness Bisti indicates that I included customers with medium diaphragm meters in concluding that a significant majority of Rate GC ratepayers had meters no larger than those for the residential class. Witness Bisti argues that I should have limited my analysis to small diaphragm meters, and, had I done so, would have concluded that "only" 34 percent of Rate GC customers used small diaphragm meters. Using a logic that I cannot follow, Witness

Bisti then applies that 34 percent as a reduction to the Company's originally proposed increase to the customer charge, resulting in a reduction from $38.82 to $35.33 per month.[3]

In the Company's analysis, however, Witness Bisti does not acknowledge the fact that the Size 20 Medium Diaphragm meters cost only slightly more than the small diameter meters, and that a significant number of residential customers use medium diaphragm meters. Moreover, the 34 percent figure cited by Witness Bisti continues to represent a large share of the Rate GC class. If the Company sets the customer charge well above the cost to serve those customers, it would mean that those smaller customers will be forced to subsidize the larger customers. In contrast, setting the customer charge at the cost to serve smaller customers and recovering the balance in the commodity charge results in a much more accurate intra-class balancing of revenues and costs between smaller and larger customers.

To address Witness Bisti's concerns, I developed an alternative version of the Company's surrebuttal COSS in which the meters cost differential for the 75 percent of smaller Rate GC customers serves as the cost basis for the Rate GC customer charge, and that value is 10 percent higher than the comparable value for residential customers using the same meters. That analysis is provided in RDK WPS3. Because the Company is unable to (or declines to) develop detailed service line cost information for Rate GC customers (as discussed above), I set the customer-related portion of services costs for the GC class equal to that for the residential class. There is no evidence that services costs for small commercial customers are higher than those for the average residential customer. Finally, because the Company incorrectly classifies all uncollectibles costs as customer-related in its COSS, I reclassify uncollectibles costs to reflect the split in rate revenues between customer charge and commodity charge. As shown in RDK WPS2, this analysis indicates that the customer cost for Rate GC is $27.73 per month, below the current Rate GC customer charge of $28.55. Thus, based on the detailed analysis in RDK WPS2 and RDK WPS3, I retain my view that no increase should be applied to the customer charge for Rate GC in this proceeding.

[3] The Company's original proposal was an increase of $10.27 per month or 36.0%, which is now reduced to an increase of $6.78 per month, or 23.7%. Even with this reduction, the customer charge increase far exceeds the Company's proposed average class increase of 14.6%.

Q. In your direct testimony, you suggested that the Company consider bifurcated customer charges for the GC class, to address the higher customer-related costs for larger customers within that class. Witness Bisti indicates in his rebuttal testimony that the Company is willing to explore options for differentiating the customer charges with the OSBA before the next base rates case. Please respond.

A. I acknowledge and appreciate the Company's willingness to consider bifurcating the customer charge for Rate GC in future rate proceedings, in consultation with the OSBA and other interested parties. I am advised by counsel that OSBA is willing to participate in such an effort. However, I am further advised that OSBA's willingness to do so has no impact on OSBA's position regarding Rate GC tariff design in this proceeding. To avoid unreasonable intra-class cross-subsidization, the customer charge for Rate GC should reflect the customer-related cost to serve smaller customers within the class, and therefore it should not be increased.

Q. In addition to the customer charge, your direct testimony indicated that the Company had no cost basis for applying a declining block commodity charge in Rate GC, and that the declining block charge differentials should be reduced. Please address the Company's response.

A. Witness Bisti indicates that PECO Gas agreed with my analysis in the last base rates proceeding, and it accepted my proposal in that proceeding to reduce the rate differential. At the time, my analysis indicated that there was little or no justification for a declining block commodity charge within the Rate GC class. That analysis implied that themodest reduction in the differential I proposed in that proceeding was only a first step in phasing out the Rate GC declining block rate differentials, unless and until the Company developed a cost analysis which justified those differentials.

Witness Bisti appears to conclude that the small first step taken in the last proceeding should have been enough, and that there is no further need to phase out the differentials. Because Witness Bisti offers neither qualitative nor quantitative analysis in support of retaining the charge differentials between the two blocks, I retain the conclusions in my direct testimony, both in the previous base rates case and the current one.

My proposed rate design for Rate GC at the revised revenue requirement is shown in detail in RDK WPS1, and summarized in Table RDK-S3 below. Note that while this proposed rate design applies a modestly larger increase to the tail block volumetric charge, the proposed rates continue to retain a significant price premium for the first block of about 23 percent. As detailed in my direct testimony and above, PECO Gas has no cost analysis supporting any price premium for Rate GC.

Table RDK-S3
RDK Rate GC Rate Design Proposal: Updated for Surrebuttal

	Current Rate	Proposed Rate	Percent
Customer Charge ($/mo.)	$28.55	$28.55	0.0%
First 200 mcf ($/mcf)	$3.9548	$4.6469	17.5%
Over 200 mcf ($/mcf)	$2.9798	$3.7755	26.7%
DSIC (%)	1.816%	0.0%	-100%
Annualization (%)	0.7334%	0.0%	-100%
Average Excl PGC/MFC/GPC	**$4.458**	**$5.108**	**14.6%**

Excludes impacts of changes to GPC and MFC.
Sources: RDK WPS1, "RevPrf RDK Surr" worksheet.

Q. Let's turn to your rate design recommendations for the TS-F and TS-I classes, starting with the customer charge. In your direct testimony, you argued that because the Company had no information regarding customer costs, you limited your proposed customer charge increase for smaller customers in the class to the class average increase. Please address the Company's response.

A. Witness Bisti responds that the Company set the customer charge for the larger customers in the class at class average allocated cost and assumed that the historical reduced rate for the smaller customers represented a reasonable differential because the Company has always done it that way.

I agree with Witness Bisti that the Company's proposal for the customer charge for the TS-F larger customers is consistent with average COSS customer costs for the class, and the customer charge for large TS-I customers is set below average customer cost. As I have no cost information about the customer-related cost for serving the smaller customers, I will accept Witness Bisti's proposal for the customer charge increase. The impacts of this

change are shown below in my rate design proposals for both TS-F and TS-I classes. I note, however, that this lack of cost information is another reason why separate costing for smaller and larger customers in the TS-F and TS-I classes is necessary.

Q. For setting the volumetric charges for the TS-I class, you argued in your direct testimony that there is no volumetric cost difference between smaller customers and larger customers, because the A&E allocation factor for demand-related costs in the Company's COSS is simply average volume. Has any party contested that cost analysis?

A. No. There is therefore no cost justification for volumetric charge differentials within the TS-I class. The Company should therefore begin the process of phasing out the volumetric charge differentials in this proceeding.

Q. In his rebuttal testimony at pages 17-20, PECO Gas Witness Bisti addresses your analysis of load factors as they relate to both TS-I and TS-F rates. Is your load factor analysis related to TS-I rate differentials?

A. No it is not. My load factor analysis applies only to TS-F customers, and it is addressed in more detail below. Class load factor is not relevant to cost causation under the PECO Gas costing methodology for Rate TS-I, because the TS-I A&E demand allocator is not based on peak demand at all, and it relies entirely on average demand. In effect, Witness Bisti has offered no rebuttal to my cost analysis for the Rate TS-I volumetric rate differentials between smaller and larger customers within the class.

Q. Please address Witness LaConte's position regarding Rate TS-I rate differentials.

A. Witness LaConte appears to take the positions that (a) I have defined a demarcation of customers within the TS-I rate class, (b) the Company is unable to provide the information necessary to separately allocate costs for the customers above and below the volume demarcation line, and (c) because cost information is not available, no rate changes are permissible. I disagree on all counts. First, the 18 mmcf per year demarcation is in the Company's tariff. The Company determined that entirely separate rates should apply to customers above and below that point. This is not my definition or recommendation. Second, the information needed to separately allocate costs between the customer groups is

almost certainly available. The Company simply declines to provide it. As the customers in the two groups must necessarily be identified for the FPFTY for the Company to develop revenue forecasts, the associated cost parameters should be readily available. Third, the Company's basic costing methodology for assigning mains costs to the TS-I class, namely relying only on average demand, implies that there is no per-mcf cost differential between smaller and larger customers, save for the impact of the lower meters costs for smaller customers in the customer charge. As such, phasing out the volumetric charge differentials is fully justified by the cost information that is available.

Q. What, then, is your proposed rate design for the TS-I class, as adjusted for the customer charge issue and the revised COSS?

A. My revised proposal for Rate TS-I is shown in Table RDK-S4 below and detailed in RDK WPS1. As shown, the proposal makes a modest step toward eliminating the volumetric charge differential, reducing the volumetric charge premium for small customers from 88 percent to 56 percent. Note also that the increase for the larger customers in the class averages only 1.8 percent, which does not violate rate gradualism principles.

Table RDK-S4
RDK Alternative Rate TS-I Rate Design Proposal: Surrebuttal Update

	Under 18 mmcf	Over 18 mmcf	Differential
Current Rates			
Customer Charge ($/mo.)	$233.00	$277.21	-15.9%
Volumetric Charge ($/mcf)	$1.5931	$0.8484	87.8%
Average Charge* ($/mcf)	$1.98	$0.89	122.0%
Proposed Rates			
Customer Charge ($/mo.)	$322.66	$379.36	-14.9%
Volumetric Charge ($/mcf)	$1.543	$0.8484	55.6%
Average Charge* ($/mcf)	$1.86	$0.91	104.5%
Percent Increase			
Customer Charge ($/mo.)	38.5%	36.8%	--
Volumetric Charge ($/mcf)	-17.1%	0.0%	--
Average Charge* ($/mcf)	-6.2%	1.8%	--

* Current rate tariff charges include the effect of the DSIC. Averages excludes negotiated rate customers; excludes PGC and backup related charges.
Sources: RDK WPS1, "RevPrf RDK Surr" tab.

Q. Turning to rate design issues for the TS-F class volumetric charges, please review the issues.

A. As I explained in my direct testimony, the Company offers no cost analysis in support of its proposal to maintain the existing percentage differential between the volumetric charge for customers with annual volume below 18 mmcf per year and customers above 18 mmcf per year. That volumetric charge differential is quite large, with smaller customers paying more than double the rate for larger customers. Such a large rate differential should have some cost basis.

As I also explained in my direct testimony, within the PECO Gas cost construct, one potential justification for a higher rate for smaller customers would be that smaller customers have a lower load factor, and therefore a higher cost to serve on a per-mcf basis. As I demonstrated, based on this factor, the appropriate ratio between the volumetric charge for the two customer groups should be the inverse of the ratio of load factors for the two customer groups.

However, the Company has offered no analysis of its own as to the relative load factor for the two groups of customers within the TS-F class. Similarly, PAIEUG Witness LaConte offers no independent analysis of the relative load factors of the two customer groups. Both parties, however, critique my analysis.

In my direct testimony, I offered two general approaches for evaluating the relative load factors for the TS-F customer groups, one based on analysis that I prepared in the last base rates case and one based on updated analysis for the current case. The Company correctly identified an error in my analysis from the last base rates case, and I corrected that error in response to PECO-OSBA-IV-1. I also modified that analysis to present the results excluding obvious outliers, which were skewing part of the analysis.

To frame the issue, the Company proposes to set the volumetric charge for customers with annual loads below 18 mmcf at 2.1 times the volumetric charge for customers with annual loads above 18 mmcf. Thus, in light of the Company's refusal to provide detailed cost information for these sub-classes or to conduct its own analysis, the only justification for the

Company's proposed differential would be that the ratio of the large customer load factor to the small customer load factor is 2.1.

Q. What is Witness LaConte's conclusion regarding your analysis?

A. Witness LaConte opines that my analysis relies on "stale" data from the last base rates proceeding, and therefore is not relevant to the current proceeding.

Q. Is Witness LaConte correct?

A. No, although Witness LaConte may have been misled by a text error in my direct testimony. As I explained in my direct testimony, part of my analysis relied on a statistical analysis of the Company's monthly data. The text of my direct testimony indicated that this analysis was conducted for the last case. In fact, that analysis was based on data provided to Company's response in this proceeding to OSBA-I-2(d), which was provided in Attachment OSBA-I-2(a). Had Witness LaConte reviewed that analysis which was filed with my direct testimony in RDK WP2, it would have been clear that the analysis relied on data for the most recent past five years through December 2021. It is therefore not stale.

Moreover, if Witness LaConte's argument about stale data is applied to my analysis, the only non-stale data in this proceeding regarding the relative load factors is that from my statistical analysis. And my statistical analysis indicates a load factor ratio for large-to-small TS-F customers of 1.43, far below the Company's proposed differential. Thus, under Witness LaConte's theory of stale data, the Company's proposal should be rejected.

Q. Please address the Company's response to your load factor analysis.

A. Witness Bisti appears to accept that my load factor analysis represents a credible approach to evaluating whether the TS-F volumetric rate differentials between small and large customers are reasonable. Witness Bisti ignores the results of my statistical analysis of recent monthly data, which indicates that the load factor ratio is 1.4, and focuses on my analysis from the last base rates case (which Witness LaConte dismisses as "stale"). Witness Bisti indicates that, once corrected, my analysis of the class load factors indicates a range for the ratio of 1.33 (using a simple average) to 2.18 (using a weighted average). As I explained in response to PECO-OSBA-IV-1, the fact that there is such a substantial difference between the simple average and the weighted average indicates that outliers are

skewing the analysis. My analysis without the outliers demonstrates that a volumetric charge ratio of 2.1 is not justified by the analysis. Moreover, Witness Bisti's complaint that I used an arbitrary method for selecting outliers is refuted by the fact that my analysis produces robust results using a variety of different criteria for outliers. This analysis was all provided to the Company. A summary of estimated load factor ratios is shown in Table RDK-S5 below.

Table RDK-S5
Estimated Load Factors for TS-F Customers

	Under 18 mmcf	Over 18 mmcf	Ratio
Current Case Analysis			
Statistical Analysis 2017-2021	36.8%	51.8%	1.41
Prior Case Customer-Specific Analysis			
Full Sample Simple Average	34.4%	45.6%	1.33
Full Sample Wtd Average	20.3%	44.1%	2.18
Exclude Over 100% LF, Under 10% LF, Simple Average	34.1%	45.6%	1.34
Exclude Over 100% LF, Under 10% LF, Wtd Average	29.2%	44.1%	1.51
Exclude Over 100% LF, Under 5% LF, Simple Average	33.5%	45.6%	1.36
Exclude Over 100% LF, Under 5% LF, Wtd Average	28.3%	44.1%	1.56
Exclude Single Customer, Simple Average	34.5%	45.6%	1.32
Exclude Single Customer, Wtd Average	26.7%	44.1%	1.65

Note: The single customer excluded in the last two rows is a large customer with a reported load factor of 0.3 percent.
Sources: RDK WP4 Corrected, PECO-OSBA-IV-1.

Q. Witness LaConte indicates that your proposed increase in the volumetric charge for larger TS-F customers of 37% constitutes rate shock, because it is 1.8 times the system average. Please respond.

A. I respectfully disagree with Witness LaConte, for a number of reasons:

- The Company's proposed limit for a class increase is 2.0 times system average. My proposal for the volumetric charge increase for the larger TS-F customers was below that value, which would be 40.2 percent.

- As a quibble, the 37 percent value for the volumetric charge increase was modestly overstated, because if fails to reflect the impact of the DSIC. If the DSIC is recognized in current rates, the increase was about 34 percent.

- The Company proposes an increase for the customer charge for both small and large customers of over 50 percent. Witness LaConte appears to accept that proposal without complaint for rate shock, thereby applying a double standard for what constitutes rate shock for the increase to any particular charge within a tariff. The customer charge increase, of course, affects smaller customers more than larger customers in the class.

- The rate shock "rule of thumb" of 1.5 or 2.0 times system average usually applies to class average increases, not to the impact on any particular charge within the tariff. Thus, my analysis evaluates the overall average rate impact for both the small customer group and the large customer group of all changes in the base rates charges, including the DSIC roll-in, the customer charge and the commodity charge.

- The 37 percent increase value was based on the Company's revenue requirement for the TS-F class in its initial filing. As a result of the modifications to the Company's COSS and proof of revenue analysis, all of which result from my analysis and testimony, the overall magnitude of the increase needed from the TS-F base rates charges is materially reduced. The impacts of that reduction on my proposal are shown below.

Q. What, then, is your proposed rate design for the TS-F class?

A. My proposal is detailed in RDK WPS1 and summarized in Table RDK-S6 below. As shown, the increase to the commodity charge for the larger TS-F customers is down to 30.0 percent (28.0 percent recognizing the effect of the DSIC phaseout), which is less than 1.5 times system average. Overall, the increase for the larger customers in the class would

average 28.9 percent, compared to a system average increase of 20.1 percent, a ratio of 1.44. This proposed design reduces the volumetric charge differential from 2.10 to 1.84, still well above that implied by the vast majority of my load factor analysis. Note also that the rate for the smaller customers within the class is still more than double the average rate for the larger customers, without any credible cost analysis from the Company supporting that differential.

Table RDK-S6
RDK Alternative Rate TS-F Rate Design Proposal: Surrebuttal Update

	Under 18 mmcf	Over 18 mmcf	Differential
Current Rates			
Customer Charge ($/mo.)	$184.00	$221.07	-32.1%
Volumetric Charge ($/mcf)	$1.9416	$0.9267	109.5%
Average Charge* ($/mcf)	$2.25	$0.98	130.2%
Proposed Rates			
Customer Charge ($/mo.)	$280.17	$336.62	-16.8%
Volumetric Charge ($/mcf)	$2.2163	$1.2047	84.0%
Average Charge* ($/mcf)	$2.64	$1.33	109.2%
Percent Increase			
Customer Charge ($/mo.)	52.3%	52.3%	--
Volumetric Charge ($/mcf)	14.1%	30.0%	--
Average Charge* ($/mcf)	17.1%	28.9%	--

* Current rate tariff charges include the effect of the DSIC. Averages exclude negotiated rate customers and PGC-related charges.
Sources: RDK WP1, "RevPrf RDK" tab.

Q. At page 20 of rebuttal testimony, Witness Bisti indicates that the Company proposes to conduct an analysis similar to my own of the relative load factors of smaller and larger transportation customers, as an input to rate design. Please respond.

A. I of course welcome efforts by the Company to evaluate the relative costs of service for smaller and larger customers within both the TS-F and TS-I rate classes. Moreover, I acknowledge that the Company's analysis could likely include information regarding individual customer load factors that was not available to me in this proceeding. Nevertheless, regarding the Company's proposal, I observe:

- Load factor analysis is not relevant for Rate TS-I. Costs assigned to that class are not based on customer contract or peak demands.

- Cost analysis of the sub-groups of TS-F and TS-I customers would be better performed within the COSS by defining separate rate classes, thereby recognizing not only load factor differences, but also meters/services costs, direct assignment impacts, any of the other cost factors cited by Witness Ding, and more accurate O&M and A&G costing. If PECO Gas is concerned about proliferation of rate classes in its COSS, it can eliminate the MV-I, IS, and TCS classes (if they are not already mooted by continuing customer attrition), and replace them with an allocated revenue credit from those classes.

- The Company's analysis should also address the analysis that I present in response to PECO-OSBA-V-1, namely that a large number of TS-F customers appear to have maximum demands that exceed the TCQ, to determine whether TCQ represents a reasonable proxy for the maximum demand for TS-F customers under design weather conditions.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT RDK-1S

ELECTRONIC WORKPAPERS OF ROBERT D. KNECHT

RDK WP1S – Near Replication of PECO Gas Rebuttal COSS

RDK WP2S – RDK WP1S with GC Customer Cost Analysis

RDK WP3S – Meters Cost Analysis

*****Workpapers will be delivered in excel format via email simultaneous to email service of Rebuttal Testimony*****

EXHIBIT RDK-2S

REFERENCED INTERROGATORY RESPONSES (Not Previously Provided)

PECO-OSBA-II-1

PECO-OSBA-IV-1 (with attachment)

PECO-OSBA-V-1 (with attachment)

*****Workpapers will be delivered in excel format via email simultaneous to email service of Rebuttal Testimony*****

PECO Energy Company

Base Rates Case, FPFTY Ending 31 December 2023

Docket No. R-2022-3031113

OSBA Responses to PECO Interrogatories Set II

PECO-OSBA-II-1

Refer to OSBA Statement No. 1, p. 27, lines 10-12. Please provide an illustrative calculation in Microsoft Excel format, with formulas intact, to support Mr. Knecht's statement that "the per-mcf allocated cost to serve for the Rate NGS customers as a group is presumably substantially lower than that for the other TS-F and TS-I rate classes."

Response:

As I indicated in my direct testimony (at page 27, lines 8-10), this conclusion was based on my understanding that the direct assigned customer(s) (i.e., TS-F and TS-I customers for whom plant costs are direct assigned rather than allocated using the standard cost allocation methods) are NGS customers. Thus, my statement was based on a comparison of unit costs for "allocated customers" to unit costs for "direct assigned customers."

In preparing my direct testimony, I did not conduct a detailed evaluation of the costs for the direct assigned customer(s), but I did observe that the directly assigned design day demand represented more than 10% of the non-direct-assigned TS-F design demand, while directly assigned mains plant was substantially less than 10% of the allocated mains gross plant. This pattern is consistent with my experience that directly assigned mains costs typically imply a much lower unit cost than allocated mains, particularly when a customer component of costs is not reflected in the allocation.

However, to respond to this request, I compiled the net allocated plant and net directly assigned plant for mains, services, and the various metering/regulating accounts. (376, 378, 379, 380, 381, 382), from my workpapers.

Rate TS-F/TS-I Allocated Plant Unit Costs Mains, Services, and M&R Equipment ($000)				
	Allocated Costs		**Direct Assigned Costs**	
Gross Plant	152,008	62,504	15,366	12,160
Acc. Dep'n	(31,535)	(13,619)	(353)	(5,030)
Net Plant	120,474	48,885	15,013	7,130
Annual Mcf	9,154,602	8,571,420	2,799,197	4,741,484
Unit Cost	$13.16	$5.70	$5.36	$1.50
Sources: RDK WP1, Attachment OBA-I-1(d)				

This analysis would appear to generally confirm the observation in my direct testimony, namely that the unit cost for the direct assigned customer(s) is less than that for the allocated customer(s).

However, in reviewing this analysis, I observe that the direct assigned design day demand for Rate TS-F is 6,500 mcf per day, while the average day direct assigned demand is 2,799,197/365 = 7,669 mcf per day, implying a TS-F load factor for the direct assigned customer(s) of well over 100 percent. Such a result does not appear to be consistent with the Company's assertion that TS-F design day demands are set based on the TCQ. Until this anomaly is resolved, I cannot conclude with confidence that the unit costs for the direct assigned customer(s) are lower than those for the allocated customer. Moreover, this anomaly may affect the overall results of the Company's cost allocation study.

PECO Energy Company

Base Rates Case, FPFTY Ending 31 December 2023

Docket No. R-2022-3031113

OSBA Responses to PECO Interrogatories Set IV

PECO-OSBA-IV-1

PECO-OSBA-IV-1. Refer to OSBA Statement No. 1, page 35, line 23, where Mr. Knecht references "ratio (1.25 to 1.53)," a calculation derived from Mr. Knecht's workpaper RDK WP4. Please provide an explanation as to why Mr. Knecht's calculations only included data starting at excel line 291 and why the calculations did not include data from excel lines 5 to 290.

Response:

RDK WP4 in this proceeding is a copy of my RDK WP4 from the Company's last base rates proceeding. The spreadsheet formulae referenced in the interrogatory appears to contain an inadvertent error, in both the workpaper from the last case and the current filing. Attached is a corrected version of RDK WP4. As shown in that workpaper, simply correcting the formula to include all TSF customers changes the quoted range from "1.25 to 1.53" to "1.33 to 2.18."

This range represents the ratio of large TS-F customer (over 18mmcf/year) load factor to smaller TS-F customer (under 18mmcf/year) load factor, evaluated using a simple average (the lower end of the range) and a weighted average (the upper end). In reviewing the updated calculation, I observe that such a substantial difference between the simple average (1.33) and the weighted average (2.18) often implies that there are outliers in the data that are skewing the result. I therefore reviewed the data more carefully, and I identified (a) a small set of TS-F customers with extremely low load factors, which may result from data errors or a from a shortened period

of service (less than a full year), and (b) a small set of customers with load factors over 100%, which may result from data errors or extraordinary circumstances. I therefore recalculated the averages excluding all customers with load factors below 5% and above 100%. This analysis eliminated only 12 of 489 TS-F customers, and it resulted in a range of load factor ratios of 1.36 (simple average) to 1.56 (weighted average). These calculations are also shown in the attached corrected workpaper.

I conclude that excluding the outliers is a superior approach for rate design analysis, because rate design should be based on the load patterns of the vast majority of customers, and not skewed by an extraordinary few. Moreover, correcting the cited range in my direct testimony from "1.25 to 1.53" to "1.36 to 1.56" has no impact on the conclusions or recommendations in that testimony regarding the appropriate volumetric charge differential for Rate TS-F.

PECO Energy Company

Base Rates Case, FPFTY Ending 31 December 2023

Docket No. R-2022-3031113

OSBA PECO Interrogatories Set V

PECO-OSBA-V-1

PECO-OSBA-V-1. Refer to OSBA Statement No. 1-R, page 7, lines 7-8. Please provide the basis for Mr. Knecht's statement that "many TS-F customers have consistently exceeded their contract demand values without apparent penalty."

Response:

The statement was based on my review of the data provided by the Company in response to OSBA-I-2 in this proceeding, that was provided with my direct testimony as RDK WP2.

To respond to this interrogatory, I have more formally conducted that review, by comparing the reported TCQs and Max Use values for each TSF customer from the Company's response. I have attached that analysis as RDK WP2 TS-F Design Day Demand Review PECO-OSBA-V-1.xlsx. The analysis shows that of the 591 TS-F customers listed by the Company, the number of customers with a higher maximum usage than TCQ in each year are as follows:

2018	327
2019	287
2020	187
2021	77
2022	203

In short, a large percentage of TS-F customers exceed contract demands.

Regarding the "without apparent penalty" phrase, I was referring to any distribution rate penalties imposed on TS-F customers for exceeding the TCQ (which PECO Gas uses for base

rates costing). I did not locate any reference to a base rate penalty for contract demand overruns in the TS-F tariff, and there do not appear to be any base rate overrun penalties in the Company's proof of revenue for the TS-F class. TS-F customers who are standby sales customers may incur overrun penalties, but those are irrelevant to base rate costing and pricing.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2022-3031113**
PECO Energy Company (Gas Division)	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Surrebuttal Testimony labelled OSBA Statement No. 1-S and associated Exhibits RDK-1S and RDK-2S are true and correct to the best of my knowledge, information, and belief, and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 19 Pa. C.S. § 4904 (relating to unsworn falsification to authorities).

Date: August 4, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3031113**
	:	
PECO Energy Company-Gas Division	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

Laura J. Antinucci, Esquire
Barrett C. Sheridan, Esquire
Mackenzie C. Battle, Esquire
Darryl A. Lawrence, Esquire
Office of Consumer Advocate
555 Walnut Street, 5th Floor
Harrisburg, PA 17101
lantinucci@paoca.org
bsheridan@paoca.org
mbattle@paoca.org
Darryllwarence@paoca.org
(Counsel for OCA)

Karl R. Pavlovic
Dante Mugrace
PCMG & Associates LLC
22 Brookes Avenue
Gaithersburg, MD 20877
OCAPECOGAS2022@paoca.org

Anthony E. Gay, Esq.
Jack R. Garfinkle, Esq.
Brandon J. Pierce, Esq.
Caroline S. Choi, Esq.
PECO Energy Company
2301 Market Street
P.O. Box 8699
Philadelphia, PA 19101
anthony.gay@exeloncorp.com
jack.garfinkle@exeloncorp.com
brandon.pierce@exeloncorp.com
caroline.choi@exeloncorp.com

Scott B. Granger, Esquire
Bureau of Investigation & Enforcement
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
sgranger@pa.gov

Byron Goldstein
2365 Geneva Avenue
Glenside, PA 19038
BGoldmarketing@RCN.com

Lauren N. Berman, Esq.
Ria M. Pereira, Esq.
John W. Sweet, Esq.
Elizabeth R. Marx, Esq.
Pennsylvania Utility Law Project
118 Locust Street
Harrisburg, PA 17101
pulp@pautilitylawproject.org

Kenneth M. Kulak, Esq.
Mark A. Lazaroff, Esq.
Brooke E. McGlinn, Esq.
Catherine G. Vasudevan, Esq.
Morgan, Lewis & Bockius LLP
1701 Market Street
Philadelphia, PA 19103
ken.kulak@morganlewis.com
mark.lazaroff@morganlewis.com
brooke.mcglinn@morganlewis.com
catherine.vasudevan@morganlewis.com

Roger D. Colton
Fisher Sheehan & Colton
34 Warwick Road
Belmont, MA 02478
OCAPECOGAS2022@paoca.org
Consultant for OCA

Brian LaTorre
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
blatorre@pa.gov

Anthony Spadaccio
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
aspadaccio@pa.gov

Elena Bozhko
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
ebozhko@pa.gov

Billie LaConte
Kitty Turner
J. Pollock, Incorporated
12647 Olive Boulevard - Suite 585
St. Louis, MO 63141
kat@jpollockinc.com

Esyan Sakaya
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
esakaya@pa.gov

Terri Cooper-Smith
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
tcsmith@pa.gov

Lisa Gumby
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
lgumby@pa.gov

Christine Wilson
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
cswilson@pa.gov

Robert Horensky
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
rhorensky@pa.gov

Richard G. Webster, Jr., VP
Regulatory Policy & Strategy
PECO Energy Company
2301 Market Street - S15
Philadelphia, PA 19103
dick.webster@exeloncorp.com

Harry Geller
118 Locust Street
Harrisburg, PA 17101
hgeller@pautilitylawproject.org

Charis Mincavage, Esquire
Adeolu A. Bakare, Esquire
Diamond U. Wade, Esquire
McNees Wallace & Nurick LLC
100 Pine Street
P. O. Box 1166
Harrisburg, PA 17108-1166
cmincavage@mcneeslaw.com
abakare@mcneeslaw.com
dwade@mcneeslaw.com

Joseph Kubas
Pennsylvania Public Utility Commission
Bureau of Investigation and Enforcement
Commonwealth Keystone Building
400 North Street
Harrisburg, PA 17120
jkubas@pa.gov

The Honorable F. Joseph Brady
Administrative Law Judge
Pennsylvana Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107
fbrady@pa.gov

DATE: August 4, 2022

/s/ Steven C. Gray

_____

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney I.D. No. 77538

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2022-3031113**
	:	
PECO Energy Company-Gas Division	:	

CERTIFICATE OF SERVICE

I hereby certify that true and correct copies of the foregoing have been served via email (*unless other noted below*) upon the following persons, in accordance with the requirements of 52 Pa. Code § 1.54 (relating to service by a participant).

The Honorable F. Joseph Brady
Administrative Law Judge
Pennsylvania Public Utility Commission
801 Market Street, Suite 4063
Philadelphia, PA 19107
fbrady@pa.gov

Barrett C. Sheridan, Esquire
Mackenzie C. Battle, Esquire
Darryl A. Lawrence, Esquire
Office of Consumer Advocate
555 Walnut Street, 5th Floor
Harrisburg, PA 17101
OCAPECOGAS2022@paoca.org

Karl R. Pavlovic
PCMG & Associates LLC
22 Brookes Avenue
Gaithersburg, MD 20877
OCAPECOGAS2022@paoca.org

Anthony E. Gay, Esq.
Jack R. Garfinkle, Esq.
Brandon J. Pierce, Esq.
Caroline S. Choi, Esq.
PECO Energy Company
2301 Market Street
P.O. Box 8699
Philadelphia, PA 19101
anthony.gay@exeloncorp.com
jack.garfinkle@exeloncorp.com
brandon.pierce@exeloncorp.com
caroline.choi@exeloncorp.com

Scott B. Granger, Esquire
Bureau of Investigation & Enforcement
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
sgranger@pa.gov

Byron Goldstein
2365 Geneva Avenue
Glenside, PA 19038
BGoldmarketing@RCN.com

Lauren N. Berman, Esq.
Ria M. Pereira, Esq.
John W. Sweet, Esq.
Elizabeth R. Marx, Esq.
Pennsylvania Utility Law Project
118 Locust Street
Harrisburg, PA 17101
pulp@pautilitylawproject.org

Kenneth M. Kulak, Esq.
Mark A. Lazaroff, Esq.
Brooke E. McGlinn, Esq.
Catherine G. Vasudevan, Esq.
Morgan, Lewis & Bockius LLP
1701 Market Street
Philadelphia, PA 19103
ken.kulak@morganlewis.com
mark.lazaroff@morganlewis.com
brooke.mcglinn@morganlewis.com

Roger D. Colton
Fisher Sheehan & Colton
34 Warwick Road
Belmont, MA 02478
OCAPECOGAS2022@paoca.org
Consultant for OCA

Hubert Matthews
367 Burmont Road
Drexel Hill, PA 19026-3525
fluffy3670.ts@gmail.com

John Walko
519 Swede Street
Norristown, PA 19401
john@skilkennylaw.com

Charis Mincavage, Esquire
Adeolu A. Bakare, Esquire
Diamond U. Wade, Esquire
McNees Wallace & Nurick LLC
100 Pine Street
P. O. Box 1166
Harrisburg, PA 17108-1166
cmincavage@mcneeslaw.com
abakare@mcneeslaw.com
dwade@mcneeslaw.com

Billie LaConte
Kitty Turner
J. Pollock, Incorporated
12647 Olive Boulevard - Suite 585
St. Louis, MO 63141
kat@jpollockinc.com

Richard G. Webster, Jr., VP
Regulatory Policy & Strategy
PECO Energy Company
2301 Market Street - S15
Philadelphia, PA 19103
dick.webster@exeloncorp.com

DATE: September 12, 2022

/s/ Steven C. Gray

_____

Steven C. Gray
Senior Supervising
Assistant Small Business Advocate
Attorney I.D. No. 77538