COMMONWEALTH OF PENNSYLVANIA

July 5, 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. UGI Utilities, Inc. – Gas Division / Docket No. R-2021-3030218

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 Direct Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1, the Rebuttal Testimony and Exhibit of Robert D. Knecht, labeled OSBA Statement No. 1-R and the Surrebuttal Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1-S, 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 I.D. No. 77538

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

COMMONWEALTH OF PENNSYLVANIA

April 20, 2022

Administrative Law Judge Joel H. Cheskis
Administrative Law Judge Gail Chiodo
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Gas Division / Docket No. R-2021-3030218

Dear Judge Cheskis and Judge Chiodo:

Enclosed please find the Direct Testimony and Exhibits of Robert D. Knecht, 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 I.D. No. 77538

Enclosures

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

Office of Small Business Advocate
Forum Place 1555 Walnut Street, 1st Floor | Harrisburg, PA 171011717.783.2525 | Fax 717.783.2831 | www.osba.pa.gov

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2021-3030218**
	:	
UGI UTILITIES, INC. (Gas Division)	:	

Direct Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design

Date Served: April 20, 2022

Date Submitted for the Record: June 2, 2022

DIRECT 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 am an independent economic consultant, specializing in the preparation of analysis and expert testimony in the field of regulatory economics. For more than 30 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 have provided testimony in a variety of proceedings involving both the Electric and Gas Divisions of UGI Utilities, Inc., its former subsidiaries Penn Natural Gas and Central Penn Gas, and the subsidiaries' predecessor utilities PG Energy, PPL Gas, and PFG/North Penn Gas, beginning in 1996. 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 the filing of UGI Utilities, Inc. – Gas Division ("UGI Gas" or "the Company"), to evaluate whether the Company's cost allocation, revenue allocation, and rate design proposals are consistent with sound regulatory economics and policy and are fair and reasonable to small business customers. Consistent with Pennsylvania practice, I have also been asked to provide OSBA's positions with respect to the Company's proposed weather normalization adjustment ("WNA") mechanism, and with respect to the claim for plant costs related to the heat content adjustment factor.

Q. Please summarize the Company's filing from a cost allocation/rate design perspective.

A. The salient features of the Company's proposal are as follows:

- The Company proposes a base rate increase of $82.3 million, or 12.8 percent of base rate revenues, for the fully projected future test year ("FPFTY") ending September 30, 2023.[1] This filing follows base rate cases in 2016, 2019, and 2020, summarized in Table RDK-1 below. Prior to the 2016 filing, UGI Gas had not filed a base rate since 1996.[2]

Table RDK-1 Recent UGI Gas Base Rate Increase Cases				
Docket No.	**Test Year Ending**	**Proposed Increase ($mm)**	**Award Amount ($mm)**	**Award Percent**
R-2015-2518438	9/30/2017	$58.6	$27.0	46%
R-2018-3006814	9/30/2020	$71.1	$30.0	42%
R-2019-3015162	9/30/2021	$74.6	$20.0	27%
Total		**$204.3**	**$77.0**	**37.7%**
R-2021-3030218	9/30/2023	$82.7	--	--
The three prior proceedings' revenue requirements were resolved by settlement.				

- The Company justifies the proposed rate increase as a result of its significant capital spending, for both asset replacement and system expansion. The Company's revenue requirement claim includes a book equity share of capital of 55.1 percent and an allowed return on equity of 11.2 percent.[3]

[1] The Company also proposes a modest change in the Merchant Function Charge ("MFC") which results in an additional increase of $0.5 million related to uncollectibles for gas sales.

[2] In the intervening years, UGI Gas acquired PG Energy in 2006 and PPL Gas Utilities, Inc. in 2008. These utilities were operated and regulated independently, and then merged in 2018. Virtually all regulatory and rate differences between these companies have been eliminated, save for certain continuing rate differentials, which are addressed further herein.

[3] Each 100 basis points (1.0 percent) in allowed RoE results in about $25 million in revenue requirement at statutory income tax rates, all other factors being equal.

- In its cost of service allocation study ("CSAS"), the Company generally follows the methodology that it has advanced in the last few base rate proceedings. Mains costs are allocated using an "average and excess" allocation methodology with a non-standard weighting methodology. The results of the Company's CSAS indicate that the residential class ("Rate R/RT") exhibits a rate of return at current rates below system average, the small and medium commercial/industrial rate classes (Rates N/NT and DS) exhibit rates of return modestly above system average, and the large C&I (Rate XD) and interruptible (Rate IS) rate classes exhibit rates of return well above system average.

- The Company's proposed allocation of the rate increase among the rate classes reflects the results of its CSAS, summarized in Table RDK-2 below. Based on the Company's CSAS, the revenue allocation for all classes results in substantial progress toward cost-based rates.[4] The rate increase for the R/RT class is limited to just under 1.5 times system average, which results in a class rate of return at proposed rates that remains moderately below system average. Rate reductions for the XD and IS classes reflect the reset of the Distribution System Improvement Charge ("DSIC"), without any corresponding increase to base rate charges.

[4] In making this observation, I do not rely on the "indexed rate of return" metric used by the Company, because that metric (a) generally overstates progress toward cost-based rates, and (b) can in some cases incorrectly show progress toward cost-based rates when none exists. My conclusion is based on the revenue-cost ratio metric, as shown in RDK WP1.

Table RDK-2 UGI Gas Proposed Revenue Allocation: FPFTY Ending 9/30/2023			
Class	**Present Rates RoR**	**Dollar Increase ($000)**	**Base Rate Percent Increase**
R/RT	4.3%	$68.12	18.1%
N/NT	7.3%	$14.53	10.4%
DS	8.6%	$0.65	1.9%
LFD	9.4%	$1.53	3.4%
XD-Firm	14.0%	($0.96)	-2.6%
Interruptible*	13.5%	($1.05)	-4.4%
Total	**6.1%**	**$82.74**	**12.6%**
* Includes Rate IS and Rate XD-Interruptible. Source: RDK WP1			

- The Company's proposed rate design for the R/RT and N/NT classes (which together represent nearly 80 percent of present rate revenues) involve disproportionately large increases to the fixed monthly customer charges, at 36.6 and 27.7 percent respectively.

- The Company proposes to eliminate the rate differentials in Rates N/NT and DS between customers in the south and central operating areas and customers in the north district. This proposal results in intra-class north/other increase differentials of 18.4%/8.4% for Rate N/NT, and 24.7%/-4.1% for Rate DS. The Company argues that the large increase for customers in the north district are reasonable because they are within 2.0 times the 12.6 percent system average increase.

- The Company proposes to adopt a weather normalization adjustment ("WNA") mechanism for Rates R/RT and N/NT. This mechanism would adjust each customer's billing determinants for non-summer months to reflect the difference between actual and normal weather.

2. Cost Allocation

Q. What is a utility cost allocation study?

A. A utility cost allocation study ("CSAS") 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 distribution utilities use an "embedded cost" approach to cost allocation, in which accounting book costs are assigned among the rate classes, rather than a marginal cost approach. Cost allocation analysts generally agree that costs should, to the extent practicable, be assigned among rate classes on the basis of "cost causation," such that costs caused by a particular class of customers are assigned to that class.

A CSAS 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 CSAS serve in a utility rate proceeding?

A. The CSAS informs both the assignment of the rate increase among customer classes ("revenue allocation") and the design of rates to recover those costs. Revenue allocation is often used to move rate revenue more into line with allocated costs from the CSAS for each rate class. 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. What are the most important cost allocation issues for a natural gas distribution company ("NGDC") such as UGI Gas?

A. A CSAS allocates rate base and associated capital costs, distribution expense, customer accounts/service expense, expense, administrative/general ("A&G") expense and taxes.[5] Often, costs are allocated on a derivative basis, based on costs already allocated. For example, depreciation, income taxes and return are allocated in the same manner as or in

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

proportion to rate base. General plant and A&G costs are typically allocated based on some combination of overall plant, O&M expense or labor cost allocations. Thus, the overall results of a CSAS are substantially driven by the allocation of a few large asset accounts. These "big ticket" issues for NGDC cost allocation are generally:

- Classification of mains costs, potentially into peak demand, throughput and/or customer components. For UGI Gas, mains represent 50 percent of rate base.
- Allocation of meters and services costs. UGI Gas meters and services account for 32 percent of rate base.[6]
- Definition and derivation of the peak-demand allocation factor, including the treatment of interruptible load in the allocator.

My testimony in this proceeding addresses the mains cost allocation method and the development of the demand allocator. The Company reports that its mains and services plant allocation is based on direct assignment of costs based on plant records, which is the best method for those costs where reliable data are available. As such, I do not address that issue in detail.

As part of my evaluation, I first replicated the Company's CSAS using my own spreadsheet model, and then developed an alternative version that reflects the changes I propose in this testimony. Electronic versions of these models are filed with this testimony, denoted RDK WP1 and RDK WP2 respectively.[7]

Q. Please address the basics of embedded cost allocation of NGDC mains costs.

[6] These percentages are based on rate base before the deferred tax offset.

[7] In my testimony in previous UGI Gas proceedings, I explained why it would be more reasonable for the Company to segregate Rate XD-Interruptible customers from those in the Rate IS class for cost allocation purposes, and I modified the CSAS accordingly. See OSBA Statement No. 1 at Docket No. R-2020-2019-3015162, pages 26-27. While I retain my view in this respect, I did not undertake that effort in this proceeding as it would not affect my conclusions.

A. NGDC mains costs are incurred to (a) interconnect the customers who take gas distribution service, and (b) provide sufficient capacity in each segment of the distribution system to meet the "design day" demands of firm service customers downstream from that segment.

With the enormous improvement in GIS and system modeling technology over the past few decades, one might think that NGDCs would be able to use that technology to specifically allocate the cost of individual mains segments to customers served downstream from those mains. In fact, UGI Gas developed such an approach for its 1996 base rates case. Alas, however, UGI Gas (and the other Pennsylvania NGDCs) continue to rely on hoary cost allocation methods, none of which rely on detailed modeling of how costs are actually incurred, and which produce radically divergent results depending on the method chosen.

In these traditional approaches to mains cost allocation, the first decision involves the "classification" of mains costs into costs that are "customer-related" and "demand-related." For those utilities that include a "customer-component" of mains costs, the classification method generally involves determining the "fixed" costs associated with a minimum-sized distribution system (or a statistically-modeled zero-volume system) and classifying that portion of the mains cost as customer-related. The conceptual logic for this method is flawed, of course, because there is no reason to conclude that the fixed costs for any particular mains segment are proportional to the number of customers served by that segment. However, some analysts argue that the cost to extend the distribution system, in terms of mains footage, is higher per unit of demand for smaller more geographically distributed customers than for larger customers or those concentrated in business districts. This logic would justify including some mechanism like a customer component to reflect these economies of scale in cost allocation. However, the existing methods for deriving a customer component are not based on this cost model.

The second consideration for mains cost allocation is the choice of the allocation factor for the "demand-related" costs. In Pennsylvania, the most common choices are the following:

Peak Demand: Costs are allocated in proportion to each class's share of system "design day" peak demand, which represents the capacity needed to serve the class under extreme weather conditions. The logic for this approach is that the mains must be sized to meet peak day demand.

Peak and Average ("P&A"): Costs are allocated based on a weighted mix of design day peak demand and average day demand.[8] Weighting the two components is typically 50/50. This approach suffers from the conceptual flaw that no mains costs are caused by average day demand – if mains costs were sized based on average demands, gas customers would be without heat on the coldest days of the winter. A main sized to meet a 100 mcf per day load costs the same whether that main is used at 100 mcf per day on every day of the year, or if that main only averages 20 mcf per day over the course of the year.

Average and Excess ("A&E"): Costs are allocated based on a weighted mix of average demand and "excess demand," where excess demand is measured as the difference between each customer's design day demand and average demand. The standard weighting factor for the A&E allocator is to apply the system load factor to the average component of the allocator (and one minus the system load factor to the excess component). The traditional A&E method is essentially a peak demand method that is adjusted to reflect the diversity of customer load. Diversity refers to the difference between the sum of individual customer peaks and system-wide peaks. Thus, if all customers peak at the same time, there is zero load diversity. The A&E method can be arithmetically expressed as a linear combination of the peak demand allocator and an average demand allocator. More load diversity implies a higher weighting for the average demand component. In the special case where there is zero load diversity and the system load factor weighting is used for the allocator, the A&E allocator is arithmetically identical to the peak demand allocator. Because gas customers' peak demands are weather-related, NGDCs generally exhibit little in the way of demand diversity, and traditional A&E allocation factors are thus very similar to peak demand allocators.

Q. Does the Commission have a policy regarding mains cost allocation?

[8] Average day demand is the annual customer load divided by 365 days. Arithmetically, average day demand and annual consumption are identical for cost allocation purposes.

A. The Commission indicates that it does not have a standard policy regarding mains cost allocation, and that it intends to evaluate the issue on a case-by-case basis.[9] Nevertheless, in its recent decisions, the Commission has relied substantially on precedent with respect to mains cost allocation.[10] With respect to the issue of mains plant classification, the Commission has consistently rejected the inclusion of a customer component for mains costs (although it has approved the use of a customer component for joint-use electric distribution plant, where the cost causation logic is the same). Regarding the allocation method for mains, the Commission has approved both P&A and A&E methods, as summarized below:

National Fuel Gas (1994):	83 Pa. PUC 262 (1994)	P&A
PPL Gas (2007):	R-00061398	A&E
PGW (2007):	R-00061931	A&E
Columbia Gas (2021)	R-2020-3018835	P&A[11]
PECO Gas (2021)	R-2020-3018929	A&E

Further, in the 2021 PECO Gas matter, the Commission indicated that the A&E method was more appropriate than the P&A method used in the Columbia matter because PECO's *". . . distribution mains system is designed to meet the demands of its system on a design day that all customers can be served. . . . Therefore, we conclude that the excess demand component of PECO's distribution mains system garners considerable weight in the balance of mains costs."*[12] As Columbia Gas (and all other Pennsylvania NGDCs) also size their mains to meet design day demand, it is unclear whether the Commission made some specific finding regarding the topology of the PECO Gas system that makes the A&E method more appropriate. As a participant in both the PECO Gas and Columbia Gas

[9] Non-Proprietary Version Opinion and Order, Docket No. R-2020-3018929, Order Entered June 22, 2021 ("PECO Order"), at 230-231.

[10] Opinion and Order, Docket No. 2020-3018835, Order Entered February 19, 2021 ("Columbia Order"), at 213-214.

[11] In its decision, the Commission correctly observed that no party offered an A&E approach in the proceeding. Columbia Order at 214.

[12] PECO Order, at 229.

proceeding, I do not recall that any evidence was presented that PECO Gas' distribution planning criteria were different from those used by Columbia Gas. As such, the Commission's logic in the PECO Gas matter would appear to reasonably apply to all Pennsylvania NGDCs.

Q. What approach does UGI Gas use in this proceeding?

A. The Company classifies all mains costs as demand-related (i.e., zero customer component) and allocates the costs using a modified load-factor weighted A&E method.

For the large industrial Rate XD-F and XD-I customers, the Company directly assigns the cost of the specific mains used by those customers to the respective classes. These customers are generally located in close proximity to interstate transmission lines, and the specific mains are identifiable. Thus, the average demands and peak demands for those customers are set to zero for the development of the class allocation factors.

However, in developing the load factor for developing the weighting factors for average demand and excess demand, the Company uses the system load factor including the XD customers, and it uses zero as the peak demand for all Rate IS and XD-I customers. Thus, the Company uses a load factor of 42.1 percent for weighting its A&E allocator, rather than the 26.9 percent that would result from a traditional interpretation of the A&E method.

The upshot of the Company's method is that the UGI Gas A&E factor is arithmetically equivalent to a P&A allocator that is weighted 79 percent peak, 21 percent average.[13]

While this particular mains cost allocation approach does not explicitly address any particular design features of the UGI Gas distribution systems, it does produce an allocation method that lies between the A&E and P&A methods recently approved by the Commission. I therefore accepted the Company's classification/allocation approach for mains cost in this proceeding.

Q. Please address the allocation of mains costs to interruptible customers.

[13] See RDK WP1 "Allocs" worksheet for supporting calculations.

A. In theory, interruptible customers can provide significant value to a gas distribution system, as those customers can be interrupted during periods of extreme weather or other stresses on the distribution system. Thus, the utility can use the interruptibility of these customers to avoid expanding capacity, and thus avoid costs. From a strict cost causation perspective, some analysts therefore argue that interruptible customers do not contribute to mains cost causation, and they assign a peak demand allocation factor of zero. In those cases, rates for interruptible customers are generally set based on value of service criteria, rather than allocated cost.

In this proceeding, the Company proposes to set the "excess" portion of the A&E allocator to zero for the interruptible customers, while including the average portion of demand in the allocator. In so doing, the Company implicitly treats interruptible customers as having a peak demand equal to their average demand. As a result, the allocation method results in an allocation of mains costs to these customers that lies between zero and the full cost share that would result if interruptible customers' peak demands were recognized. Thus, like the Company's A&E allocator in general, this approach has little in the way of cost causation logic, but it produces an allocation that lies between the extremes.

In this light, and recognizing that rates for Rate IS are set by negotiation, I do not contest this approach in this proceeding.

Q. How does the Company derive its design day demands to develop the excess demand allocation factor for its A&E method?

A. The Company's design day workpapers were provided in OSBA-I-4. Based on that workpaper, the Company's method is at follows:

1. Begin with the system-wide design day demand from last year's Section 1307(f) "PGC" proceeding;

2. Add in contract demands for large customers that were not included in the PGC proceeding;

3. Set the design day demands for the DS, LFD and XD-Firm customers at the contract demand levels;[14]

4. Split the remaining design day demand between the R/RT and N/NT classes based on a factor called "actual average consumption per customer per day" multiplied by number of customers in the class. It is necessary to develop a method to split the design day demand for these two classes because the classes are not daily metered, and the design day for the two classes (the "Core Market") is derived together in the PGC proceedings using a statistical regression methodology.

Q. Do you agree with this approach?

A. Based on the information that is currently available, I do not. First, it is incorrect to segregate design day demands between R/RT and N/NT customers based on average consumption. Such segregation must reflect the relative design day demands of the two classes. Second, the source for the Company's actual average consumption factors is not specified and is not clear. Third, the Company's methodology produces an anomalous result for the R/RT and N/NT classes, namely that the load factor for the Rate N/NT class is materially lower than that for the Rate R/RT class, at 19.7 percent and 21.9 percent respectively. In my experience, the load factors for residential and small commercial gas customers are either similar in magnitude, or the commercial class exhibits modestly higher load factors. Moreover, the Company's analysis in this case results in a significant shift in load factors since the last case, where the R/RT and N/NT load factors were 20.6 percent and 20.9 percent respectively.

Q. Did you conduct any independent analysis of the relative load factors of R/RT and N/NT customers?

A. I did. When daily metered data are not available, analysts can use monthly data to estimate the base load and heating load for a rate class, using either regression or simple arithmetic methods. I applied a regression method to both the monthly class data provided in response to OSBA-I-3, and to the more detailed monthly class data provided in the various

[14] The Company's workpaper indicates that it relies on daily firm requirements ("DFRs") for contract demands for the LFD and XD-F classes, and the maximum daily quantity ("MDQ") for Rate DS.

attachments to OSBA-I-18. I also applied a simple arithmetic method to the monthly data in OSBA-I-3. All of these analyses show the same pattern: the historical load factor for the N/NT class is modestly higher than that for the R/RT rate class. My analysis is attached to this testimony at RDK WP3.[15]

I therefore modified the Company's split of the design day demand between R/RT and N/NT customers to be consistent with the load factors derived in my analysis.

This is the only modification that I made to the Company's cost allocation methodology.

Q. How do the results of your modified CSAS compare to the Company's results?

A. Table RDK-3 below shows class rates of return at present rates for (a) the Company's CSAS, (b) my replication of the Company's CSAS in RDK WP1, and (c) my alternative CSAS with the modified peak demand allocators in RDK WP2. As shown, my replication matches the Company's results, and my alternative model produces modestly different returns for Rates R/RT and N/NT.

Table RDK-3
Comparative CSAS Results:
Class Rates of Return at Current Rates

	UGI Gas CCAS	RDK Replication	RDK Alternative
R/RT	4.33%	4.33%	4.09%
N/NT	7.28%	7.28%	8.13%
DS	8.61%	8.61%	8.61%
LFD	9.44%	9.44%	9.44%
XD-F	14.01%	14.01%	14.01%
Interruptible	13.46%	13.46%	13.46%
Total	**6.14%**	**6.14%**	**6.14%**

Sources: Exhibit D, RDK WP1, RDK WP2

[15] In preparing this analysis, I also estimated implied design day demands for the DS and LFD classes. My analysis of the DS class produced load factor results that were similar to the Company's MDQ load factors. However, for the LFD class, my analysis implies a materially lower load factor than that implied by the Company's DFR method. I did not make an adjustment in this respect because service to LFD customers above the DFR is not guaranteed, but my analysis may imply that UGI Gas is implicitly providing more capacity under extreme weather conditions to the LFD customers than that implied by the DFRs.

3. **Revenue Allocation**

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 basic principles for revenue allocation in regulated utility base rate proceedings?

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 base rates proceedings 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

- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively price-elastic demand. [16]

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 ACOSS can be simulated at both present and proposed rates to

[16] 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 development of utility rates.

evaluate the magnitude of "progress" has been made toward the policy of achieving cost-based rates.

As a practical rule-of-thumb, rate gradualism is often reflected in revenue allocation by limiting the increase for any particular class to 1.5 to 2.0 times the system average.

Q. Do you agree with the Company's proposed revenue allocation, as presented above?

A. I have two disagreements.

First, there I disagree that rate decreases should be assigned to the Rate XD and Rate IS classes. These customers are subject to negotiated rates, which have already been accepted by the customers. In particular, the Rate IS tariff requires that the negotiated rates be set based on the cost of alternative fuels. There is therefore no competitive need to provide rate reductions to these customers. I propose to set the rate increases for those customer classes at zero and (implicitly or explicitly) roll the current DSIC revenues into the regular rates.

Second, under my alternative CSAS, the Company's proposed revenue allocation is inequitable to the Rate N/NT class, as it would result in relatively small progress toward cost-based rates compared to the other rate classes. I therefore propose to further modify the Company's proposed revenue allocation by (a) setting the rate increase for the R/RT class at 1.5 times the system average increase (1.5 x 12.6% = 18.9%), and (b) set the increases for the N/NT, DS and LFD classes to produce equivalent progress toward cost-based rates.[17] Using the normalized revenue-cost ratio metric, my proposal results in the revenue allocation summarized in Table RDK-4 below, and detailed in RDK WP2.

Table RDK-4 RDK Alternative Proposed Revenue Allocation				
	Increase $mm	**Increase %**	**R-C Ratio Current Rates***	**R-C Ratio Proposed Rates***
R/RT	$71.45	18.9%	88.3%	93.8%
N/NT	$ 9.04	6.5%	114.4%	106.4%
DS	$ 1.38	4.1%	115.8%	107.0%
LFD	$ 0.88	2.0%	123.2%	110.4%
XD-Firm	$ 0.00	0.0%	145.3%	130.7%
IS/XD-I	$ 0.00	0.0%	152.8%	133.7%
Total	**$82.74**	**12.6%**	**100.0%**	**100.0%**

* Based on RDK proposed CSAS methodology in RDK WP2.
Source: RDK WP2

As shown in Table RDK-4, no class is assigned a rate decrease, no class exhibits an increase that is more than 1.5 times the system average, and every class makes material progress toward cost-based rates as measured by the revenue-cost ratio metric. The N/NT, DS and LFD classes all move a little more than halfway toward cost-based rates. For example, at present rates, the revenue cost ratio for Rate N/NT is 115.8%. As my proposed rates, the class moves to 107.0%, moving 8.8 (115.8 – 107.0) percentage points closer to cost-based rates, of the 15.8 percentage points needed to set rates at costs.

In making this proposal, I recognize that I assign a larger rate increase to the Rate DS class than that proposed by UGI Gas. However, the Company's revenue allocation proposal for Rate DS was designed to try to make the harmonization of the rates within that class somewhat less painful to those customers in the northern operating district. As I explain below, while the Company should continue to make progress toward harmonizing rates, full harmonization in this proceeding is not yet reasonable.

Q. Do you have recommendations in the event the Commission awards UGI Gas with an increase below the $82.74 million requested?

A. In order to retain the parameters that I use in my revenue allocation, a proportional scaleback approach is not unreasonable. Thus, for example, if the allowed increase is set at $35 million (a little better for the Company than the average of the last three cases), the increase for the residential class would be $71.45 million * $35 million / 82.74 million = $30.22 million, or 8.0 percent. The XD and IS class rate changes would remain at zero. The progress toward cost-based rates for the N/NT, DS and LFD classes would necessarily be reduced, but that effect is unavoidable without assigning an increase to the R/RT class that is more than 1.5 times system average.

4. Rate Design

Q. Please summarize the Company's proposal to harmonize the base rates tariff for Rates N/NT and DS in this proceeding.

A. Prior to 2018, UGI Utilities, Inc. had one operating division that was a regulated gas utility and two subsidiary gas utilities, namely UGI Central Penn Gas and UGI Penn Natural Gas. At Docket Nos. A-2018-300381/2/3, the Commission approved the merger of these three entities into the UGI Utilities, Inc. (Gas Division), although separate regulations and tariffs continued to apply to each of t three "rate districts" (denoted South, Central, and North respectively). However, for several years prior to the merger, the Company had substantially harmonized the rate class definitions and eligibility rules for the three entities. In the Company's last two base rates proceedings at Docket No. R-2018-3006814 and Docket No. R-2020-3015162, the Company proposed to fully harmonize the tariffs for the three rate districts, both with respect to the purchased gas cost ("PGC") rate charged to utility gas sales customers and the base rates tariff charges for distribution and related services.

In both of those proceedings, I objected to the full harmonization for base rates, due to the rate shock implications.[18] These effects would have been unreasonable and excessive for the Rate N/NT customers and especially Rate DS customers in the North rate district. The settlement in the former proceeding provided for full harmonization of the PGC rate, and it harmonized base rates for the South and Central districts. However, it retained base rate differentiations between the North rate district and the South/ Central rate districts, for Rate N/NT and Rate DS. The settlement of that first case explicitly recognized that the

[18] OSBA Statement No. 1, Docket No. R-2018-3006814, pages 27-30. OSBA Statement No. 1, Docket No. R-2020-3015162, pages 38-41.

Company could propose full harmonization in its next base rates case, and that parties could oppose such a proposal.[19] In the most recent base rate case, the settlement indicates that the Company's proposal to harmonize the rates was withdrawn without prejudice, with the provision that "[t]he Company may propose this in the Company's next base rate case, but no sooner than January 1, 2022."

In this proceeding, the Company again proposes to fully harmonize the base distribution rates for Rate N/NT and Rate DS. UGI Gas witness Sherry A. Epler concludes that this proposal does not violate the traditional bounds for rate shock because the proposed increases for the North district customers in those classes are less than twice the system average increase.[20]

Q. What is the Company's specific proposal for base rates tariff charges for Rate N/NT and Rate DS in this proceeding?

A. Table RDK-5 below shows the proposed changes in tariff charges, as well as the bill implications for the average customer.

[19] The Settlement states, "For Step 1, the Rate N/NT North rate district rates will be increased by twelve (12) percent and Rate DS North rate district rates will be increased by twenty (20) percent, with Rate N/NT and Rate DS South and Central rate districts being set uniformly by class to recover the remaining N/NT and DS revenue requirements, respectively. For Step 2, the parties reserve their rights to oppose the Company's proposed rates and propose alternative rates."

[20] UGI Gas Statement No. 1 at page 19, footnote 1. Witness Epler's upper limit of two times system average appears to only apply to small business customers. For revenue allocation in this proceeding, the Company proposes to assign an increase of approximately 1.5 times the system average to the residential class, leaving that class still falling well short of a system average rate of return. Similarly, Witness Epler complains that North district Rate DS customers have been under-paying their cost of service for a three-year period. However, Witness Epler's concerns in this respect do not appear to apply to the R/RT class, where revenues have fallen short of allocated costs for decades.

Table RDK-5 UGI Gas Rate Design Proposal: Rate N/NT and Rate DS						
	Rate N/NT			Rate DS		
	Current Rates	Proposed Rates	Percent	Current Rates	Proposed Rates	Percent
Customer Charge ($/mo.)	23.50	30.00	27.7%	260.00	260.00	0.0%
Distribution Charge ($/mcf) South/Central	3.6271	4.0413	11.4%	2.9730	2.9977	0.8%
Distribution Charge ($/mcf) North	3.2653	4.0413	23.8%	2.1335	2.9977	39.3%
Typical Bill ($/Year) South/Central	$1,986	$2,153	8.4%	$24,832	$23,821	-4.1%
Typical Bill ($/Year) North	$1,817	$2,153	18.5%	$18,876	$23,821	26.2%
Notes: 1. The base rate tariff charges under current rates exclude the DSIC, which would be at 5.0 percent without a base rate increase. 2. The typical bill is based on customer and distribution charges inclusive of DSIC, excluding PGC and other charges for specific functions. Sources: RDK WP1.						

With this proposal for Rate N/NT, the Company proposes an overall average increase of a little over 10 percent, but the increase for the North district customers is some 2.1 times the increase for the South/Central rate district. For Rate DS, the typical increase for a North district customer would exceed 26 percent, while other customers in the class would see a material rate decrease.

I respectfully submit that imposing a 26 percent rate increase on one group of customers in this proceeding is not reasonable.

Q. What of the Company's argument that the Rate DS increase is within two times the system average?

A. Even if it were reasonable to accept an upper bound of two-times system average, the Company's argument quickly falls apart when the reality of a credible rate increase intrudes. As parties are aware, the actual rate increase award in a Pennsylvania base rates proceeding, either as a result of settlement or Commission decision, is almost always materially lower than the filed increase. Given the specific context of the current case, I deem it likely that any awarded rate increase will be significantly lower than the $82.7 million claimed. Based on the history of the past three proceedings shown in Table RDK-1 above, the awarded increase may very well be below $35 million (5.3 percent).

However, fully harmonizing the rates in a single rate proceeding will require rate increases to the North district customers that are nearly as large as those proposed in the filing, particularly for the Rate DS class. That is, the relative impact of harmonizing the rates on the North district customers does not get fully scaled back with a reduction in the overall rate increase.

For example, suppose the overall rate increase was reduced to $35 million, or about 5.3 percent, and the increases for Rates N/NT and DS were scaled back proportionately from the Company's proposed revenue allocation. I calculate that full harmonization of the Rate N/NT rates would require increases for North district customers of about 12.8 percent (which would be 2.4 times system average) and harmonization of the Rate DS rates would require an increase of 25.8 percent (4.8 times the system average). The basic arithmetic fact is that harmonizing Rate DS, and to a less extent Rate N/NT, will require a very large rate increase for North district customers, regardless of the level of the overall utility increase.[21]

Q. What do you recommend for this proceeding?

A. I recommend that the increase for North district customers be limited to no more than 1.5 times the system average increase, which would be 18.9 percent at the Company's full proposed increase. Similarly, I propose that the increase for both groups of customers within the N/NT and DS classes be proportionately scaled back for any reduction in the Company's claimed rate increase. Thus, if the overall increase is reduced from $82.7 to

[21] In theory, this increase could be mitigated by providing a substantial decrease to Rate DS overall. I deem such an outcome to be highly improbable, based on experience.

$35.0 million, the increase for North district customers would be limited to an increase of $35.0/$82.7 * 18.9% or 8.0 percent.

A detailed proof of revenues for rates at the Company's full proposed revenue requirement with my revenue allocation and these recommendations is included in RDK WP2. The specific tariff charges are shown in Table RDK-6 at the end of this testimony.

Note that my recommendation in this respect applies to any approved revenue allocation, for both the N/NT and DS rate classes. However, as shown in RDK WP2, at my proposed revenue allocation with the reduced assignment to Rate N/NT (before the effects of any scaleback), this limit would allow for full harmonization of the N/NT rates. The Rate DS volumetric charges would continue to be differentiated, even with the typical North district customer being assigned an 18.9 percent increase, while other DS customers would see an increase of less than 1.0 percent.

Q. Please address the issue of the customer charge for Rate N/NT.

A. As shown in Table RDK-5 above, the Company proposes to assign a nearly 28 percent increase to the Rate N/NT customer charge, compared to an overall class average increase of about 10 percent. Because the customer charge for the rate districts has already been harmonized, this proposal is not intertwined with the issue of harmonizing the North district rates. Nevertheless, this proposal will materially shift the nature of cost recovery in the Rate N/NT class, it and will result in a substantial rate increase for smaller customers within the class. For example, for small businesses with loads that are similar to an average residence, the Company's rate design proposal will result in an increase of 13.5 percent for South and Central district customers, and a nearly 20 percent increase for North district customers.

Q. How should the results from the CSAS be used to inform setting the customer charge for the Rate N/NT class?

A. The simplest approach would be to sum the costs classified to "customer-related" in the CSAS, and divide by the number of monthly bills. The problem with that approach is that, unlike the residential class, the Rate N/NT class includes customers with a wide array of sizes and costs to serve. Larger customers within the customer class require larger meters and more costly service lines. Thus, if a single customer charge applies to all customers in the class, using the average cost method will simply mean that small customers are inequitably subsidizing larger customers. For this reason, some Pennsylvania NGDCs have adopted differentiated customer charges for general service customers. UGI Gas has not made such a proposal in this proceeding.

Thus, in the UGI Gas single customer charge framework, the correct cost basis for the customer charge should be the customer related cost to service the smaller customers within the class, leaving the volumetric charge to absorb the costs for the more expensive meters used by the larger customers. While the cost for a small Rate N/NT customer is not directly available from the CSAS, the customer-related cost for a residential customer is. Since small Rate N/NT customers can be similar in size to a residential customer, this approach results in a reasonable proxy.

Using my CSAS simulation at the UGI Gas proposed rates, the full customer component of residential class costs is about $33 per customer per month. As such, the Company's $30 proposed customer charge is near the upper bound of the cost range for small Rate N/NT customers.

Q. How does the Company's proposal compare to the customer charge used by other Pennsylvania NGDCs for smaller non-residential customers?

A. The $30 charge would be at the upper end of the range, but not outside it. Table RDK-6 below shows the monthly customer charge for small non-residential customers.

Table RDK-6 Non-Residential Customer Charges: Pennsylvania NGDCs	
	$/month
National Fuel Gas Dist'n C&PA (< 250 mcf)	$19.89
Peoples Natural Gas SGS (< 500 mcf)	$20.00
UGI Gas N/NT (current)	$23.50
Philadelphia Gas Works GS-C	$25.35
PECO Gas GC*	$28.55
Columbia Gas SGSS/SCD/SGDS**	$29.92
UGI Gas N/NT (proposed)	$30.00
Peoples Gas (TWP) SGS (<500 mcf)	$35.00
* PECO proposes a $38.82 customer charge in its current base rates proceeding. ** Columbia proposes a $34.23 customer charge in its current base rates proceeding. Note: Customer charges exclude the effects of DSIC, TCJA or other multipliers. Sources: Company websites	

Q. With that background, what do you recommend?

A. Because the Company's proposal is justified on a cost basis at its proposed rates, I do not object to the $30 charge if the full increase were to be granted. However, to mitigate the rate shock for small customers, the increase should be scaled back with any overall reduction in the Company's proposed revenue requirement. Thus, for example, if the Company's allowed increase is $35.0 million rather than $82.7 million, the customer charge increase would be scaled back; i.e., $23.50 + $6.50 * $35.0/$82.7 = $26.25 per month.

Q. In light of your recommendations for revenue allocation, rate harmonization and the Rate N/NT customer charge, what is your recommended rate design for Rates N/NT and DS?

A. Table RDK-7 below provides my recommendation. Detailed supporting calculations are provided in RDK WP2.

Table RDK-7 RDK Rate Design Proposal: Rate N/NT and DS at Full Revenue Requirement						
	RDK Rate N/NT			RDK Rate DS		
	Current Rate	Proposed Rate	Percent	Current Rate	Proposed Rate	Percent
Customer Charge ($/mo.)	23.50	30.00	27.7%	260.00	260.00	0.0%
Distribution Charge ($/mcf) South/Central	3.6271	3.8673	6.6%	2.9730	3.1668	6.5%
Distribution Charge ($/mcf) North	3.2653	3.8673	18.4%	2.1335	2.7992	30.1%
Typical Bill ($/Year) South/Central	$1,986	$2,076	4.5%	$24,832	$24,989	0.6%
Typical Bill ($/Year) North	$1,817	$2,076	14.2%	$18,876	$22,450	18.9%

Notes:

1. The base rate tariff charges under current rates exclude the DSIC, which would be at 5.0 percent without a base rate increase.
2. The typical bill is based on customer and distribution charges inclusive of DSIC, excluding PGC and other charges for specific functions.Sources: RDK WP2.

Q. Please state OSBA's position with respect to the Company's proposed weather normalization adjustment ("WNA") mechanism.

A. The Company proposes to implement a WNA for its R/RT and N/NT classes. The mechanism would adjust customer bills in all months between October and May for the difference between actual heating degree days ("HDDs") and the normal HDDs used to develop base rates. The adjustments would occur in "real time," in that each bill would reflect both the actual and normal HDDs for the particular period that applied to that bill. The Company's mechanism would reflect a customer-specific parameter for the "base" non-heating load (based on a three-year history of summer use), and it would adjust the actual use in excess of that base amount for the ratio of normal to actual HDDs. The adjusted actual use would then serve as the volumetric billing determinant. As proposed, the WNA mechanism would not be a pilot program, and it would include no "dead band" within which no adjustments are made.

I am advised by counsel that OSBA intends to contest this proposal as not just and reasonable on the grounds that the substantial risk reduction benefits to the Company and the rate instability implications for customers associated with this mechanism are not reasonably reflected in the allowed return on capital claim in this proceeding.

Q. What is the OSBA's concern regarding the Company's cost claim related to the BTU heat content rate adjustment mechanism?

A. At Docket No. R-2021-3026078, the Company proposed, and the Commission approved, a rate mechanism designed to facilitate the incorporation of renewable gas supplies with below-average BTU content into the Company's gas distribution mix. In effect, the tariff was modified to be able to reflect geographic differences in gas energy content such that customers would all pay the same per unit of energy delivered. In its filed tariff supplement at that docket, the Company indicated, "The proposed change is intended to assure there is no impact to the utility's revenue and expenses." In this proceeding, the Company reports that it is claiming approximately $2.0 million in information system rate base associated with the adoption of this rate mechanism.[22] I am advised by counsel that based on the evidence available at this time, OSBA intends to contest this claim.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[22] See OCA-I-39, OSBA-I-16.

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-3

OSBA-I-4

OSBA-I-16

OSBA-I-18

OCA-I-39

These interrogatory responses and attachments are available on the Post & Schell Sharepoint site subject to confidentiality constraints and are incorporated by reference. OSBA will take the necessary steps to enter these responses into the record at the appropriate time.

EXHIBIT RDK-3

ELECTRONIC WORKPAPERS

RDK WP1: Replication of UGI Gas CSAS

RDK WP2: RDK Alternative CSAS

RDK WP3: Design Day Demand Workpapers

*** Electronic workpapers will be delivered by email simultaneous to service of Direct Testimony***

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3030218**
UGI UTILITIES, INC. (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: April 20, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2021-3030218**
	:	
UGI Utilities, Inc. – 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).

Administrative Law Judge Joel H. Cheskis
Administrative Law Judge Gail Chiodo
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
jcheskis@pa.gov
gchiodo@pa.gov

Laura J. Antinucci, Esq.
Mackenzie C. Battle, Esq.
Christy M. Appleby, Esq.
Darryl A. Lawrence, Esq.
Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101
lantinucci@paoca.org
mbattle@paoca.org
cappleby@paoca.org

Carrie B. Wright
Prosecutor
Bureau of Investigation and Enforcement
PA Attorney ID No. 208185
(717) 783-6156
carwright@pa.gov

Joseph L. Vullo, Esquire
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com

Kent D. Murphy, Esq.
Michael S. Swerling, Esq.
Timothy K. McHugh, Esq.
UGI Corporation
460 North Gulph Road
King of Prussia, PA 19406
murphke@ugicorp.com
swerling@ugicorp.com
mchught@ugicorp.com

Garrett P. Lent, Esq.
Devin T. Ryan, Esq.
Lindsay A. Berkstresser, Esq.
David B. MacGregor, Esq.
Post & Schell, P.C.
glent@postschell.com
dryan@postschell.com
lberstresser@postschell.com
dmacgregor@postschell.com

Francis J. Riviello
609 Moosic Road
Old Forge, PA 18518
mjriviello@icloud.com

Elisabeth Lynch
210 Poplar Lane
Mill Hall, PA 17751
fenrivers1@yahoo.com

Paula Mercuri
3 Villa Drive
Moosic, PA 18507
qwilliams22@gmail.com

Paul Forlenza
128 Saddle Ridge Drive
Dallas, PA 19612
prf2324@comcast.net

Karen O. Moury, Esquire
Eckert Seamans Cherin & Mellott, LLC
213 Market Street, 8th Floor
Harrisburg, PA 17101
kmoury@eckertseamans.com

John W. Sweet, Esq., PA ID: 320182
118 Locust Street
Harrisburg, PA 17101
pulp@pautilitylawproject.org

/s/ Steven C. Gray

DATE: April 20, 2022

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

COMMONWEALTH OF PENNSYLVANIA

May 17, 2022

Administrative Law Judge Joel H. Cheskis
Administrative Law Judge Gail Chiodo
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Gas Division / Docket No. R-2021-3030218

Dear Judge Cheskis and Judge Chiodo:

Enclosed please find the Rebuttal Testimony and Exhibit 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 I.D. 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-2021-3030218**
UGI UTILITIES, INC. (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: May 17, 2022

Date Submitted for the Record: June 2, 2022

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

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 presented therein.

Q. What is the purpose of this rebuttal testimony?

A. This rebuttal testimony responds briefly to the cost allocation and revenue allocation recommendations of Office of Consumer Advocate ("OCA") Witness Jerome D. Mierzwa.

Q. Please summarize the changes proposed by Witness Mierzwa for the Company's cost of service allocation study ("CSAS").

A. Witness Mierzwa recommends that the Company's modified average-and-excess ("A&E") method for classifying and allocating mains costs be replaced with a 50/50 weighted peak-and-average ("P&A") methodology. Witness Mierzwa also recommends making four technical adjustments to the CSAS.

I note also that Witness Mierzwa accepted the Company's methodology for deriving the class design day demands that are used in both the A&E and P&A allocation factors. As such, I do not believe that Witness Mierzwa's CSAS is reasonable, because it relies on unreasonable estimates for the design day demands of the R/RT and N/NT rate classes.

Q. Please restate your view of the P&A methodology for classifying and allocating mains costs.

A. As I explained in my direct testimony, none of the standard methods for classifying and allocating mains costs are consistent with cost causation, and none are reasonable in this era where detailed system modelling techniques are available. The P&A method is particularly problematic, in that it relies heavily on average demand. Mains costs are not causally related to average demand. Mains are designed to meet design day demand, and to interconnect customers. However, as I also explained in direct testimony, the Company has not offered a detailed modelling approach (since 1996), and the Commission has recently accepted both the A&E method (for PECO Gas) and the P&A method (for

Columbia Gas). As the Commission has provided little guidance as to why it accepted the A&E method in PECO Gas after approving the P&A method in Columbia Gas, it is difficult to evaluate whether the Company's method or Witness Mierzwa's method is more consistent with Commission precedent. As I noted, the PECO Gas decision (using the A&E method) may be more relevant, since it involved a head-to-head comparison of the A&E and P&A methods, whereas the A&E method was not directly before the Commission in the Columbia Gas matter.

Q. Witness Mierzwa indicates that ". . . Ms. Heppenstall's Mains allocation factors are nearly identical to the results obtained when average demand allocation factors are weighted at zero, and pure peak allocation factors are weighted at 100 percent." Do you agree?

A. Not completely. As I explained in my direct testimony, I agree with Witness Mierzwa that the traditional load-factor weighted A&E method will arithmetically default to a pure peak demand allocator if there is no diversity in demand. However, the Company does not rely on the actual system load factor for weighting the average component of costs in its A&E allocator, but in fact uses an alternative weighting factor that increases the weight assigned to average demand. Its method therefore produces an allocator that is 79 percent based on peak demand and 21 percent based on average demand.[1] As such, the Company's method lies between a traditional A&E approach and Witness Mierzwa's recommended P&A method.

Q. What do you conclude from Witness Mierzwa's views on mains cost classification and allocation?

A. I acknowledge that Witness Mierzwa's method is consistent with that approved by the Commission for Columbia Gas. However, I conclude that the Company's method is also reasonably consistent with the Commission's decision in PECO Gas (wherein the P&A method was rejected), the Company's method has a reduced reliance on average demand which is not a contributor to mains cost causation, and the Company's method represents

[1] These values are derived in RDK WP1 in the "Allocs" worksheet at cells B119:K127.

a compromise between a traditional A&E method and Witness Mierzwa's P&A method. I therefore continue to rely on the Company's modified A&E method in this proceeding.

Q. What technical changes does Witness Mierzwa propose for the CSAS?

A. Witness Mierzwa proposes the following changes:

- Manufactured gas plant remediation costs included in accounts 740-742 should be allocated in proportion to overall O&M expense, consistent with the treatment of those costs for Accounts 930 and 932;
- Forfeited discounts should be allocated based on actual historical forfeited discounts, rather than penalty revenues;
- Reconnection fees should be allocated based on actual reconnection fees, rather than the overall revenue requirement;
- The Company's acknowledged error for sub-functionalizing costs in Account 874 should be incorporated into the CSAS.

Q. Do you agree with these recommendations?

A. With the exception of Witness Mierzwa's proposed change to reconnection fees, I do.

Regarding reconnection fees, these charges are imposed to recover the costs associated with reconnections. Therefore, the revenues are an offset to those costs, and should be allocated in the same manner. Thus, if the Company were to allocate the *costs* incurred for reconnections based on actual reconnections, Witness Mierzwa's approach for the reconnection *fees* would be reasonable. However, the Company does not separately allocate the costs for reconnections, and it implicitly uses an aggregate O&M allocator for those costs. As such, it is not appropriate to allocate reconnection fees based on actual history, but rather based on aggregate O&M costs. In effect, reconnection costs and reconnection fees should both be allocated on the same basis.

Q. Have you replicated Witness Mierzwa's CSAS, using your cost allocation model?

A. I have. It is attached as RDK WPR1.

Q. Will you reflect the changes proposed by Witness Mierzwa with which you agree in your CSAS?

A. I will. I intend to update my CSAS in surrebuttal testimony to address any changes that result from the Company's rebuttal filing, as well as to incorporate the three technical changes offered by Witness Mierzwa with which I agree. I will similarly update my revenue allocation and rate design recommendations, as necessary.

Q. What is Witness Mierzwa's revenue allocation recommendation?

A. Witness Mierzwa's revenue allocation is summarized in Table RDK-R1 below. Because the Company's indexed rate of return metric cannot reasonably be used to measure progress toward cost-based rates, I rely on the normalized revenue-cost ratio method. The column labeled "progress" represents how much the proposed revenue allocation moves the revenue-cost ratio toward 100%. So, for example, the R/RT revenue cost ratio moves 3.4 percentage points from 91.9% to 95.3%, out of the 8.1 percentage points needed to move from 91.9% to 100.0%, a ratio of 3.4/8.1 = 42%.

Table RDK-R1
OCA Revenue Allocation Proposal Using
OCA Cost of Service Allocation Study

	Increase $mm	**Increase %**	**R-C Ratio Current Rates***	**R-C Ratio Proposed Rates***	**Progress**
R/RT	$60.28	16.0%	91.9%	95.3%	42%
N/NT	$12.98	9.3%	114.5%	109.3%	36%
DS	$2.13	6.3%	115.2%	108.7%	43%
LFD	$5.65	12.6%	101.6%	100.1%	96%
XD-Firm	--	0.0%	133.3%	120.5%	38%
IS/XD-I	$1.70	7.1%	107.2%	100.0%	100%
Total	**$82.74**	**12.6%**	**100.0%**	**100.0%**	**--**

* Based on OCA proposed CSAS methodology, replicated in RDK WPR1.
Source: RDK WPR1

Q. Is Witness Mierzwa's proposed revenue allocation consistent with the OCA proposed CSAS?

A. Witness Mierzwa's revenue allocation proposal is *directionally* consistent with the OCA CSAS, but it appears to elevate the criterion of rate gradualism above the criterial of moving rates into line with allocated cost. In Pennsylvania, the Commonwealth Court has determined that cost is the "polestar" criterion for revenue allocation. Moreover, in terms of equity, the R/RT class has been generating revenues that fall well short of allocated costs, since at least 1996. Small and medium-sized businesses in the N/NT and DS classes have been paying for that shortfall for a similar period. Despite those considerations, Witness Mierzwa proposes an increase for the R/RT class that is only 1.27 times the system average increase, when the traditional rule of thumb for rate gradualism is to limit the increase to 1.5 or 2.0 times system average. As such, I conclude that even if the OCA CSAS methodology were adopted, Witness Mierzwa's proposed revenue allocation is not reasonable as it simply perpetuates a long-standing historical inequity.

Q. If Witness Mierzwa's CSAS is adopted, what revenue allocation would you propose?

A. Under the OCA CSAS, my recommendation is shown in Table RDK-R2 below. In developing this recommendation, I accept Witness Mierzwa's proposals for the LFD and IS/XD-I classes, because his proposals move those classes fully into line with the OCA's allocated cost. Consistent with my direct testimony, I assign a 1.5 times system average increase to the R/RT class, which still fails to bring revenues into line with allocated cost.[2] The balance of the increase is assigned to the N/NT and DS classes, so as to balance the revenue-cost ratio for those classes at proposed rates. As shown, my revenue allocation under the OCA CSAS results in considerably more progress toward cost-based rates than that offered by Witness Mierzwa. For example, this revenue allocation moves the revenue-cost ratio for the residential class from 91.9 percent to 97.7 percent, thereby making progress toward cost-based rates of 71 percent.

[2] The OCA has supported the use of these parameters in other proceedings. See, for example, OCA Statement No. 4 at page 26 at Docket No. R-2020-3018929 (the PECO Gas matter in which the Commission approved the A&E method), wherein OCA applies both the 1.5X and 2.0X increases.

Table RDK-R2
RDK Revenue Allocation Proposal Using
OCA Cost of Service Allocation Study

	Increase $mm	Increase %	R-C Ratio Current Rates*	R-C Ratio Proposed Rates*	Progress
R/RT	$71.45	18.9%	91.9%	97.7%	71%
N/NT	$3.79	2.7%	114.5%	102.8%	81%
DS	$0.15	0.4%	115.2%	102.8%	81%
LFD	$5.65	12.6%	101.6%	100.1%	96%
XD-Firm	--	0.0%	133.3%	120.5%	38%
IS/XD-I	$1.70	7.1%	107.2%	100.0%	100%
Total	**$82.74**	**12.6%**	**100.0%**	**100.0%**	**--**

* Based on OCA proposed CSAS methodology, replicated in RDK WPR1.
Source: RDK WPR1

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT RDK-R1

ELECTRONIC WORKPAPERS

RDK WPR1: Replication of OCA CSAS

UGI Gas Utilities Inc., Gas Division (UGI Gas)

RDK Workpaper #R1: Cost of Service Allocation Study YE 30 September 2023; Replication of OCA P&A Methodology

Summary at Proposed Rates: OCA Revenue Allocation Valid if "Proposed" ==> Proposed

	Total	R/RT	N/NT	DS	LFD	XD-Firm	IS	XDI
Rate Revenues	738,286,414	437,650,632	151,804,131	35,906,433	50,514,565	36,697,801	25,712,853	0
Other Revenues	10,286,321	6,226,356	2,574,653	422,270	529,645	308,842	224,555	0
Total Revenues	**748,572,735**	**443,876,988**	**154,378,783**	**36,328,703**	**51,044,210**	**37,006,643**	**25,937,408**	**0**
O&M Expense	293,485,866	196,203,254	43,995,512	12,996,950	17,312,367	14,623,036	8,354,748	0
Depreciation Expense	125,531,905	78,912,303	25,666,999	5,031,238	7,932,516	3,880,641	4,108,208	0
Other Taxes	13,657,627	8,390,788	2,536,181	672,347	927,069	659,575	471,667	0
Interest Expense (RB Rd.)	56,726,000	32,805,827	12,407,133	2,641,490	4,460,444	2,075,213	2,335,893	0
Pre-Tax Expenses	**489,401,398**	**316,312,171**	**84,605,826**	**21,342,024**	**30,632,396**	**21,238,465**	**15,270,515**	**0**
Pre-Tax Income	**259,171,337**	**127,564,817**	**69,772,958**	**14,986,679**	**20,411,814**	**15,768,178**	**10,666,893**	**0**
Income Tax (PTI, Rd)	63,347,000	31,179,393	17,053,012	3,661,457	4,985,409	3,851,498	2,609,896	0
Total Return	**252,550,337**	**129,191,251**	**65,127,078**	**13,966,712**	**19,886,849**	**13,991,893**	**10,392,889**	**0**
Rate Base	**3,169,006,045**	**1,832,702,207**	**693,126,249**	**147,567,195**	**249,183,346**	**115,932,067**	**130,494,981**	**0**
Rate of Return	**7.97%**	**7.05%**	**9.40%**	**9.46%**	**7.98%**	**12.07%**	**7.96%**	**#DIV/0!**
Total Cost of Service	**748,245,483**	**465,955,655**	**141,220,772**	**33,407,571**	**51,009,802**	**30,714,272**	**25,937,410**	**0**
Revenue/Cost Ratio	**100.0%**	**95.3%**	**109.3%**	**108.7%**	**100.1%**	**120.5%**	**100.0%**	**#DIV/0!**

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2021-3030218**
UGI UTILITIES, INC. (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-R1 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: May 17, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2021-3030218**
	:	
UGI Utilities, Inc. – 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).

Administrative Law Judge Joel H. Cheskis
Administrative Law Judge Gail Chiodo
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
jcheskis@pa.gov
gchiodo@pa.gov

Laura J. Antinucci, Esq.
Mackenzie C. Battle, Esq.
Christy M. Appleby, Esq.
Darryl A. Lawrence, Esq.
Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101
lantinucci@paoca.org
mbattle@paoca.org
cappleby@paoca.org

Carrie B. Wright
Prosecutor
Bureau of Investigation and Enforcement
PA Attorney ID No. 208185
(717) 783-6156
carwright@pa.gov

Joseph L. Vullo, Esquire
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com

Kent D. Murphy, Esq.
Michael S. Swerling, Esq.
Timothy K. McHugh, Esq.
UGI Corporation
460 North Gulph Road
King of Prussia, PA 19406
murphke@ugicorp.com
swerling@ugicorp.com
mchught@ugicorp.com

Garrett P. Lent, Esq.
Devin T. Ryan, Esq.
Lindsay A. Berkstresser, Esq.
David B. MacGregor, Esq.
Post & Schell, P.C.
glent@postschell.com
dryan@postschell.com
lberstresser@postschell.com
dmacgregor@postschell.com

Francis J. Riviello
609 Moosic Road
Old Forge, PA 18518
mjriviello@icloud.com

Elisabeth Lynch
210 Poplar Lane
Mill Hall, PA 17751
fenrivers1@yahoo.com

Paula Mercuri
3 Villa Drive
Moosic, PA 18507
qwilliams22@gmail.com

Paul Forlenza
128 Saddle Ridge Drive
Dallas, PA 19612
prf2324@comcast.net

Karen O. Moury, Esquire
Eckert Seamans Cherin & Mellott, LLC
213 Market Street, 8th Floor
Harrisburg, PA 17101
kmoury@eckertseamans.com

John W. Sweet, Esq., PA ID: 320182
118 Locust Street
Harrisburg, PA 17101
pulp@pautilitylawproject.org

/s/ Steven C. Gray

DATE: May 17, 2022

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

COMMONWEALTH OF PENNSYLVANIA

May 27, 2022

Administrative Law Judge Joel H. Cheskis
Administrative Law Judge Gail Chiodo
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120

Re: Pennsylvania Public Utility Commission v. UGI Utilities, Inc. – Gas Division / Docket No. R-2021-3030218

Dear Judge Cheskis and Judge Chiodo:

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 I.D. 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-2021-3030218**
UGI UTILITIES, INC. (Gas Division)	:	

Surrebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation

Date Served: May 27, 2022

Date Submitted for the Record: June 2, 2022

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. **<u>Introduction</u>**

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 presented therein.

Q. **What is the purpose of this surrebuttal testimony?**

A. This testimony responds to the rebuttal testimony of various UGI Utilities Inc. – Gas Division ("UGI Gas" or "the Company") witnesses, specifically:

- On cost allocation matters, Witness Constance E. Heppenstall;
- On revenue allocation matters, Witnesses Christopher R. Brown and Sherry A. Epler;
- On the issue of "harmonizing" Rates N/NT and DS, Witness Epler;
- On the Company's proposed weather normalization adjustment ("WNA") mechanism, Witness John D. Taylor.

I note that Pennsylvania Office of Consumer Advocate Witness Jerome D. Mierzwa submitted rebuttal testimony regarding cost allocation matters. However, my rebuttal testimony addresses the relevant methodological issues, and it provides my recommendation for revenue allocation in the event Witness Mierzwa's cost allocation method is adopted. As such, there is no need to respond further in this testimony.

The four topics are addressed sequentially below.

2. Cost Allocation

Q. Did the Company update its cost of service allocation study ("CSAS") in rebuttal testimony to reflect the parties' filings?

A. Yes, or at least it attempted to do so.[1] The Company submitted a summary of its revised CSAS in Exhibit D-R, and it made its electronic workpapers available to intervenors. The Company made the following changes to the CSAS from the filed version:

- In response to my direct testimony, the Company modified the design day demand allocators for the R/RT and N/NT classes to reflect the historical weather sensitivity analysis that I presented;
- In response to Witness Mierzwa's direct testimony, the Company modified the allocation of certain environmental O&M costs related to long-shuttered manufactured gas facilities so as to assign those costs only to gas sales customers and to exempt all transportation customers from any responsibility for those costs;
- Consistent with its own response to an interrogatory and Witness Mierzwa's direct testimony, the Company modified its sub-functionalization of O&M operating costs in Account 874 for meters/services between costs related to meters and costs related to services;
- In response to Witness Mierzwa's direct testimony, the Company modified its allocation of certain "other" revenues to reflect actual historical revenue patterns.

Q. Do you agree with the Company's adjustments to the design day demand allocator?

A. I do. The design day demand factor in the Company's revised CSAS in Exhibit D-R is now consistent with my recommendation.

Q. Do you agree with the Company's adjustment to O&M costs related to manufactured gas facilities?

[1] In addition to the errors detailed herein, the Company continues its practice of aggressively rounding its allocation factors to no apparent purpose. In its rebuttal CSAS under present rates, at least four of the allocation factors fail to total to 100 percent (Factors 12, 13, 14, and 15). This practice is mostly harmless, but it can result in needless distortions for rate classes with relatively low cost to serve. I eliminate this rounding in RDK WPS1.

A. No.[2] The Company claims that these costs are related to gas supply, and thus should be borne only by sales customers. The Company's argument is akin to claiming that the costs of cleaning up a buggy whip factory are causally related only to customers who now buy automobiles. The costs in question were incurred in a different era and under a different regulatory regime, notably one in which shopping for gas supplies was not permitted and all customers benefited from manufactured gas facilities. That gas utilities are allowed to recover the costs for these facilities at all, which are not "used and useful," suggests that these costs are more akin to an environmental tax than a typical utility cost of service. Moreover, it is likely that few if any of UGI Gas's current customers benefited from the manufactured gas plants which give rise to these costs.

As such, these costs are better allocated broadly across all customers, rather than assigning them only on the basis of gas sales volume. Thus, as I indicated in my rebuttal testimony, I agree with Witness Mierzwa's proposal to consistently allocate these costs across all rate classes, using the O&M expense allocator (Factor 12).

Moreover, if the Commission approves the assignment of these costs in the manner proposed by the Company, it will become necessary to establish separate rates for sales (Rates R and N) and retail transportation (Rate RT and NT). Under the Company's logic, if the manufactured gas plant costs are assigned only to utility sales customers, the retail transportation customers in Rates RT and NT have no responsibility for the costs in question and thus should pay lower rates.

Q. Do you agree with the Company's proposal to modify the sub-functionalization of Account 874 meters/services operating costs?

A. I agree with that proposal because the Company indicated that its original filing was erroneous and inconsistent with the workpaper provided in response to discovery. As a practical matter, however, implementing this modification is proving to be problematic. In developing the OCA CSAS, Witness Mierzwa correctly modified the sub-functionalization

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[2] As a technical matter, in modifying its allocation of certain manufactured gas O&M costs in Accounts 923 and 930, it failed to make a similar modification to the Labor O&M costs in those accounts. As I reject the Company's proposed method, there is no need for me to correct this error.

of Account 874 O&M costs, but the witness did not carry that calculation through to the Account 874 Labor O&M costs. Thus, the labor allocator in Witness Mierzwa's CSAS is based on an inaccurate sub-functionalization of the labor costs in Account 874.[3]

In the Company's rebuttal case in Exhibit D-R, the Company compounded the errors in Witness Mierzwa's CSAS. First, rather than modifying the sub-functionalization to be 55.1% mains and 44.9% services, the Company's calculation is reversed, and O&M costs are sub-functionalized as 44.9% to mains and 55.1% to services. (The Company subsequently corrected this error in response to informal OSBA discovery.) Second, like Witness Mierzwa, the Company fails to carry the change through to the Labor O&M cost allocation. (Although the Company indicated informally to OSBA that it intended to modify the labor allocator in the corrected version of the CSAS, the functionalization of labor costs for Account 874 in the revised CSAS is unchanged from the original filing.)[4]

Q. Do you agree with the Company's changes to the allocation of other operating revenues, as offered by Witness Mierzwa?

A. Yes and no. As I explained in my rebuttal testimony, Witness Mierzwa's proposal for forfeited discounts is reasonable, and the Company's revised CSAS adopts it. However, Witness Mierzwa's change in the allocation of reconnection revenues is not reasonable, because it should be allocated on the same basis as the cost for those reconnections, for the reasons laid out in my rebuttal. As such, I disagree with the Company's revised CSAS, as it adopts Witness Mierzwa's proposal.

Q. Have you developed a modified version of your proposed CSAS to reflect these changes?

A. I have, and it is attached in electronic form in RDK WPS1. Relative to the Company's original filing, it reflects:

[3] My RDK WPR1 CSAS follows Witness Mierzwa's method, because the object of my rebuttal analysis was to replicate the OCA CSAS and evaluate its implications for revenue allocation.

[4] See UGI Gas Exhibit D-R (Corrected) at page 21, where the Account 874 costs are split between mains and services at 51.9% mains, 48.1% services, unchanged form UGI Gas Exhibit D.

- Revised design day demand allocators;
- Allocation of all manufactured gas plant O&M costs using Factor 12;
- Sub-functionalization of both Account 874 O&M and Account 874 Labor O&M at 55.1% mains, 44.9% services;
- Allocation of forfeited discount revenues based on historical patterns.

Q. How does your revised CSAS compare to the Company's original filing and the CSAS in your direct testimony?

A. Table RDK-S1 below shows class rates of return at present rates under the four CSAS models.

Table RDK-S1
Comparison of Allocated Cost of Service Study Results
Class Rate of Return at Present Rates

	UGI Gas Filing	RDK Direct	OCA Direct	UGI Gas Rebuttal*	RDK Surrebuttal
R/RT	4.3%	4.1%	4.7%	4.1%	4.1%
N/NT	7.3%	8.1%	8.1%	7.9%	8.1%
DS	8.6%	8.6%	8.5%	8.7%	8.6%
LFD	9.4%	9.4%	6.4%	9.5%	9.4%
XD-Firm	14.0%	14.0%	12.3%	14.2%	13.9%
IS/XD-I	13.5%	13.5%	7.1%	13.5%	13.4%
Total	**6.1%**	**6.1%**	**6.1%**	**6.1%**	**6.1%**

* Partially corrected in response to OSBA informal discovery.
Source: RDK WP1, RDK WP2, RDK WPR1, UGI Gas Exhibit D-R, RDK WPS1

As shown in Table RDK-S1, all of the CSASs on file in this proceeding show that the residential R/RT classes produce revenues well below allocated cost, while all other classes produce revenues in excess of allocated cost. The only material difference for the non-residential classes is that the OCA "P&A" CSAS produces a class rate of return for the LFD class that is only slightly above system average, whereas the other "A&E" CSASs indicate that the LFD class rate of return is well above system average.

Table RDK-S1 also shows that the changes recommended by Witness Mierzwa which I incorporated into my surrebuttal testimony have almost no discernible impact on class rates of return compared to the results from the CSAS filed in my direct testimony.

3. Revenue Allocation

Q. What is the Company's position regarding your revenue allocation recommendations?

A. In my direct testimony, I explained why rate decreases should not be assigned to the XD and IS classes, that the increase for the R/RT class should be 1.5 times system average, and the balance of the increase should be used to allow for uniform progress toward cost-based rates for the N/NT, DS and LFD classes. Witness Brown presents the Company's view as to why rate reductions for the XD and IS classes are reasonable. Witness Epler addresses the issue of the maximum reasonable increase for the residential classes (R/RT).

Q. What are Witness Brown's arguments regarding the rate decreases?

A. Witness Brown makes two points. Initially, he argues that both the XD and IS classes exhibit class rates of return well above system average, and that the rate decreases are cost-justified. While I agree with Witness Brown's assessment of cost of service, I have three observations. First, Witness Brown clearly indicates that the XD and IS rates are market-based competitive rates.[5] As such, the cost of service criterion is less relevant for these rate classes than for other classes. Second, in my experience in Pennsylvania, I observe that it is unusual for the Commission to assign rate decreases to certain rate classes while other classes face large rate increases. Third, as shown in my workpapers, a zero rate increase for these classes will result in substantial progress toward cost-based rates.

Witness Brown makes a second point that the Company has been able to negotiate contracts with some XD and IS customers such that rates increase with the DSIC. Witness Brown argues that, with the DSIC reset from a base rates case, the contracts in place will necessarily result in a rate reduction from those customers. Witness Brown indicates that

[5] UGI Gas Statement No. 1-R at page 31 line 3, page 32 line 20, page 33 line 19, page 34 lines 9 and 22.

reopening those contracts to incorporate a provision to roll in the DSIC during a rate case would open the possibility that less favorable contracts would need to be negotiated.

Q. Is Witness Brown's argument regarding the contract provisions reasonable?

A. No. Consider the circumstances. These are customers who, according to the Company, have credible competitive alternatives to taking service from UGI Gas, presumably either an alternative fuel or bypass potential to interstate pipelines. In its negotiations with these customers, the Company determines that the competitive conditions are such that the customer can afford to experience rate increases associated with the DSIC. The Company then negotiates a contract in which the rates from these customers are allowed to increase with the DSIC, *only so long as those revenues flow to UGI Gas shareholders.* As long as the Company is between rate cases, the DSIC revenues flow to the shareholders. However, under the Company's negotiated contracts, as soon as new rates are imposed as a result of a base rates case, the DSIC is reset to zero, and the Company demands that the resulting revenue reduction get handed back to other ratepayers.

This approach is neither reasonable nor equitable. Negotiating a contract that is purportedly based on a customer's competitive alternatives, but which provides for an automatic rate reduction with the Company's next base rates proceeding, is unreasonable and borderline irresponsible. I recommend that the Commission not sanction this behavior by allowing the Company to force other ratepayers to pay for automatic rate decreases to competitive rates that have already been negotiated and accepted. Thus, for regulatory purposes, the allowed rate change for the XD and IS classes should be set to zero. If the Company both has the ability and chooses to re-open these contracts to negotiate more reasonable terms, it is free to do so at management's discretion.

Q. What is Witness Epler's position regarding revenue allocation to the R/RT classes?

A. Witness Epler's rebuttal states,

> "In addition, the Company continues to believe that an increase for the Rate R/RT customer class of 2.0 times the system average increase is appropriate, just, and reasonable. The Company has consistently utilized this standard in its rate cases as it does address the ratemaking principle of gradualism. An increase of 2.0 times the system average increase is further supported as appropriate for

> Rate R/RT in this case in order to move the only class demonstrating lower than system average returns closer to paying a system average rate of return; a demonstration of equity across all rate classes."[6]

I am puzzled by this rebuttal because (a) the Company did not propose a 2.0 times system average for the R/RT class in its filing, (b) I proposed a 1.5 times system average increase for the R/RT class in my direct testimony, and (c) the Company's rebuttal testimony continues to show revenue allocation for the R/RT class at 1.43 times system average, which produces a class rate of return at proposed rates that remains well below allocated cost.[7] Specifically, the system average increase is 12.62 percent, the Company's original and rebuttal proposed increase for R/RT is 18.05 percent (1.43 times system average), my proposed increase is 18.93 percent (1.50 times system average), and Witness Epler's rebuttal supports a 25.24 percent increase (2.00 times system average).[8]

In effect, Witness Epler appears to conclude that UGI Gas's own proposed allocation of the rate increase to the R/RT class is far too low, but the Company declines to change its revenue allocation to reflect Witness Epler's rebuttal testimony.

While a reasonable case could potentially be made to increase the R/RT increase to two times system average, I have not changed my recommendation for the R/RT class to reflect this apparent shift in the Company's position. As shown in my workpapers, the 1.5 times system average increase that I propose for Rate R/RT will result in material progress toward cost-based rates for all rate classes. However, I recommend that the Commission, when evaluating the various revenue allocation proposals in this case, recognize that the Company's rebuttal testimony supports a substantially larger increase for the R/RT class than that in my recommendation.

Q. Have you updated your revenue allocation analysis to reflect the changes to the CSAS?

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[6] UGI Gas Statement No. 8-R at 14.

[7] See Exhibit D-R Corrected, at Schedule A page 1 and Schedule B page 1.

[8] These values are based on tariff revenues excluding PGC costs, but including the MFC and GPC charges that apply only to sales service customers.

A. As detailed in the "SumProposed" worksheet of RDK WPS1, I developed an alternative revenue allocation based on the revised cost allocation analysis in that workpaper, using the same logic as that presented in my direct testimony. However, the differences between the surrebuttal revenue allocation analysis and that in my direct testimony are *de minimis*. As such, I retain the revenue allocation proposal in my direct testimony.

4. <u>Harmonizing Rates N/NT and DS</u>

Q. Why is there an issue regarding the harmonizing of Rates N/NT and Rate DS.

A. In 2008, UGI Utilities, Inc. ("UGIU") purchased PPL Gas Utilities Company from PPL Electric Utilities Corporation, and began operating it as UGI Central Penn Gas, Inc. ("CPG"). Also in 2008, UGIU purchased PG Energy Inc. from Southern Union Company, and began operating it as UGI Penn Natural Gas, Inc. ("PNG"). During the period in which these companies were operated and regulated as separate utilities, UGIU set rates based on the costs incurred for the individual utilities, but it undertook to harmonize rate class definitions, eligibility, and other tariff considerations across the UGIU family of gas utilities. In general, I supported UGI Gas's efforts in this respect, subject to rate gradualism and other rate design considerations.[9]

In 2018, the Commission approved a petition by UGIU et al. to merge UGI Gas, CPG and PNG into a single utility, at Docket Nos. A-2018-3000381/382/383, pursuant to a settlement among the parties (including OSBA).[10] In that proceeding, I submitted testimony that was generally supportive of the public benefits associated with the merger, but which recognized (and evaluated in some detail) the impacts on some customers if tariff rates were to be fully harmonized.[11] As detailed in that testimony, the primary negative impacts of the merger on rate harmonization would be for Rate N/NT and particularly for Rate DS customers in the PNG service territory. The settlement in that proceeding recognized that rates could not easily be harmonized, and that separate costing and rate design remained necessary for three operating areas: North (formerly PNG), Central

[9] See OSBA Statement No. 1, Docket No. R-2010-2214415; OSBA Statement No. 1, Docket No. R-2008-2079660.

[10] Joint Petition for Approval of Settlement of All Issues, Docket No s. A-2018-3000381/382/383, July 20, 2018.

[11] OSBA Statement No. 1, Docket No. A-2018-3000381 et al., at 8-13.

(formerly CPG) and South (formerly UGI Gas). Since that time, the Company has filed three base rates proceedings, it has moved away from separate costing within rate districts, and it has phased out rate differentials between the South and Central operating areas. In each proceeding, including the current one, the Company has proposed to apply rate increases far in excess of system average to North District (formerly PNG) N/NT and DS classes. While I have generally supported the Company's goal of eliminating separate costing regimes and gradually harmonizing rates, I have opposed the Company's efforts to impose rate increases on Rate N/NT and Rate DS customers that are many multiples of the system average increase, particularly when the effects of a rate scaleback are reflected.[12] It is simply not reasonable to impose enormous *relative* increases on a subset of small and medium business customers over a very short period of time simply because they had the misfortune to have their utility acquired by another utility with a higher cost structure.

Q. In your direct testimony, you recommended that the rate increase for Rate N/NT and DS customers in the former North operating area be limited to no more than 1.5 times the system average increase. How does the Company respond?

A. Witness Epler begins by stating that this is the third time the Company has attempted to harmonize the rates, and that not doing so will perpetuate an intra-class subsidy and that customers will not be treated equally. Witness Epler goes on to argue that if the Commission accepts that the principle of rate gradualism should apply to Rate N/NT and DS customers in the North district, the Commission should permit UGI Gas to increase the rates for North district customers by 2.0 times the system average in this proceeding, purportedly consistent with my recommendation for an upper limit in a recent Columbia Gas base rates proceeding.[13] Witness Epler then requests that the Company be permitted to apply another rate increase to North district customers on October 1, 2023 (presumably

[12] As I explained in my direct testimony, a scaleback of the Company's proposed rate increase has little impact on the relative intra-class cost impact of harmonization. Much of the Company's proposed increase to the North district rates is related to catching up with the current rates for the other customers in the class, and that part of the increase is not reduced with a lower overall revenue requirement.

[13] As I explained to the Company, the circumstances in the Columbia proceeding were decidedly different from those in the current case. See UGI-OBA-I-1

with offsetting reductions to rates for the other customers within each class), which would result in harmonized rates.[14]

Q. Please respond to Witness Epler's rebuttal.

A. Sadly, Witness Epler begins by blaming the victim. It is not the fault of North district customers that UGI Gas operates its gas system at a cost of service well in excess of that of the former owner, and it is not the fault of North district customers that UGI Gas continues to require an above system average rate of return from both N/NT and DS customers, which exacerbates the problem.

Second, Witness Epler refers to the lower rates from North district customers as an intra-class cross-subsidy. There is zero evidence for this statement. A cross-subsidy represents the difference between rate revenues and costs. UGI Gas offers no cost evidence in support of its position, because it no longer tracks costs by operating area. Thus, no party has any knowledge of the cost of providing service to North district customers relative to providing service to other customers. I acknowledge, of course, that the use of postage stamp rates across utilities is a common regulatory approach for utility tariffs. However, the use of postage stamp rates does not imply that intra-class geographic cross-subsidies do not exist, and the Company is wrong to claim that they exist without evidence.

Third, while I acknowledge that I have recommended an increase up to 2.0 times the system average in other Pennsylvania proceedings, based on my evaluation of the specific circumstances for those proceedings. The circumstances surrounding North district customers in this proceeding are wholly different from the proceeding referenced by Witness Epler.[15] Moreover, Witness Epler does not offer any example in Pennsylvania where a specific rate class or sub-class is singled out for a very large rate increase in a base

[14] It is unclear why the Company feels the need for a separate rate adjustment for Rate DS customers on October 1, 2023. In this proceeding, the Company argues that its rate case costs should be amortized over a single year, since it expects to file another rate case in a year. UGI Gas Statement No. 2-R at 8-11.

[15] See UGI Gas-OSBA-I-1, attached in Exhibit RDK-S2.

rate case, followed by an extraordinary supplementary increase outside of a base rate proceeding.

Finally, Witness Epler's rebuttal shows that the Company's standard for rate gradualism is different for small businesses than it is for residential customers. In this proceeding, the R/RT class exhibits a rate of return well below system average under every CSAS filed in this proceeding, and yet the Company's rebuttal testimony proposes an increase of only 1.43 times the system average for that class.[16] Moreover, the Company does not propose to impose another increase on R/RT customers on October 1, 2023 to make further progress toward cost based rates that it fails to achieve in this proceeding. In contrast, for some unlucky non-residential customers, the Company insists on a 2.0 times system average increase in this proceeding, followed by another increase on October 1, 2023.

Adopting the Company's proposal in this respect would be a clear indication that different regulatory standards apply to residential and non-residential customers. In contrast, my proposal relies on applying the same standard for rate gradualism to both residential and non-residential customers. I recommend against adopting the Company's proposals for mandatory rate harmonization on basic fairness grounds, namely that residential and non-residential customers should be treated comparably.

5. <u>Weather Normalization</u>

Q. In rebuttal testimony, Witness Taylor indicates that under the Company's proposed weather normalization adjustment ("WNA") mechanism, customers bills will be more stable and that rates will not vary from month to month. Do you agree?

A. I agree that the WNA will likely reduce the impact of weather fluctuations on the dollar cost of a customer's monthly gas distribution bill. I disagree that the rates per unit of gas consumed will not vary from month to month.[17] While Witness Taylor does not directly state as much, the witness presumably argues that the WNA adjusts volumes rather than rates. This is sophistry. Actual metered volumes are actual metered volumes. If a

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[16] I recognize, of course, that Witness Epler *says* that the maximum increase for the R/RT class should be 2.0 times system average. I caution the Commission to follow the old saw and "watch what they do, not what they say."

[17] See OSBA-I-2, attached in Exhibit RDK-S2.

customer has metered volumes of 50 mcf in January and 50 mcf in February, the customer will pay the same distribution bill in both months under current rates, but will almost certainly pay a different distribution bill under the WNA. I expect that customer will recognize that the rates have changed, even if Witness Taylor sees it otherwise.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

EXHIBIT RDK-S1

ELECTRONIC WORKPAPERS

RDK WPS1: RDK Surrebuttal Cost of Service Allocation Study

*** Workpaper will be attached via email simultaneous to service of Surrebuttal Testimony***

EXHIBIT RDK-S2

REFERENCED INTERROGATORY RESPONSES

UGI-OSBA-I-1 (without attachments)

UGI-OSBA-I-2 (without attachments)

UGI Utilities, Inc. – Gas Division ("UGI Gas" or "the Company")
Base Rates Case, FPFTY Ending September 30, 2023
Docket No. R-2021-3030218
Responses to UGI-OSBA Set I

UGI-OSBA-I-1

Reference OSBA Statement No. 1, pages 15, 20-21. In any base rate cases over the past 10 years, has Mr. Knecht ever supported setting a customer class's increase to more than 1.5 times the system average increase? If so, please identify each such base rate case and provide copies of Mr. Knecht's testimony in each such base rate case.

Response:

I did not review my base rates cases for the past ten years in preparing my direct testimony in this proceeding, and undertaking such a review would be unduly costly and time-consuming. Nevertheless, I have indeed recommended in testimony that the regulator set the rate increase for a class at more than 1.5 times the system average. A recent example is at Pennsylvania Public Utility Commission Docket No. R-2021-3024296, a base rates proceeding for Columbia Gas of Pennsylvania, Inc. A copy of my direct testimony in that proceeding is included as Attachment UGI-OSBA-I-1.

In evaluating the limits for rate gradualism, I consider a variety of factors relevant to each case, including (but not necessarily limited to) the magnitude of the system increase, the relative cost performance of each class, the overall bill impact for the class, the history of relative class rate increases, and the relevant economic environment for each rate class.

UGI-OSBA-I-2

Reference OSBA Statement No. 1, page 25. Mr. Knecht states that "I am advised by counsel that OSBA intends to contest this proposal as not just and reasonable on the grounds that the substantial risk reduction benefits to the Company and the rate instability implications for customers associated with this mechanism are not reasonably reflected in the allowed return on capital claim in this proceeding."

a) Does Mr. Knecht agree with UGI Gas witness Moul that his cost of equity analysis accounts for the Company's Weather Normalization Adjustment ("WNA") mechanism? If not, please explain in detail why.

b) Does Mr. Knecht agree with UGI Gas witness Moul that each of his Gas Group members has some form of a WNA mechanism? If not, please explain in detail why.

c) Please explain in detail what Mr. Knecht means by "rate instability implications for customers associated with this mechanism."

d) Please produce all non-privileged Documents relied upon by Mr. Knecht in making this statement and in responding to subparts (a) through (c) of this interrogatory.

Responses:

a) I respectfully disagree with Mr. Moul. Outside the cloistered world of utility rate of return analysts, independent financial experts deem the U.S. equity risk premium above the ten-year Treasury yield to be in the 5.0 to 5.5 percent range for the average risk company.[1] (See, e.g., Damodaran at https://pages.stern.nyu.edu/~adamodar/ and https://papers.ssrn.com/sol3/papers.cfm?abstract_id=4066060 , Kroll at

[1] In a welcome development in this proceeding, OCA witness David J. Garrett (OCA Statement No. 2) recognizes that allowed utility equity returns have become divorced from reality.

https://www.kroll.com/en/insights/publications/cost-of-capital/recommended-us-equity-risk-premium-and-corresponding-risk-free-rates .) Even with 10-Year T-Bonds now yielding a little under 3.0 percent, the cost of equity capital for the average risk US firm is in the 8.0 to 8.5 percent range.

Natural gas distribution utilities, of course, are below-average risk investments, measured either by systematic risk (beta) or all return variability (standard deviation). Thus, the cost of equity capital for a natural gas distribution utility should have an equity risk premium materially below the 5.0 to 5.5 percent range, and a full return materially below the 8.0 to 8.5 percent range.

In my direct testimony at Docket No. R-2020-3018929 (Attachment UGI-OSBA-2a), I demonstrated that, twenty-five to thirty years ago, the equity risk premium in utility RoE awards was in the 4.0 to 5.0 percent range. Since that time, adoption of various regulatory initiatives have served to reduce the risk of utility investments, including (i) restructuring of many electric and gas utilities (reducing fuel price and generation risk), (ii) fuel-adjustment clauses, such as Pennsylvania's PGC, (iii) automatic capital passthrough mechanisms, such as Pennsylvania's DSIC, (iv) weather normalization mechanisms (reducing utility weather risk), and (v) rate decoupling mechanisms (which shift virtually all volume risk to ratepayers). Despite this trend of risk reduction, utility regulators have allowed the implied equity risk premium in RoE awards to rise to 7.0 to 8.0 percent, far above that of average risk US corporations. While the reasons for this trend cannot be known with certainty, I hypothesized in Attachment UGI-OSBA-2a that this trend reflects (a) higher utility spending in regulatory proceedings, (b) excessive regulatory reliance on DCF methods for deriving RoE (with the circular reliance on analysts' growth estimates combined with the bizarre assumption that natural gas distribution companies will experience dividend growth rates that exceed GDP growth rates forever) and regulatory capture (wherein regulators and governments see utilities as partners in achieving social aims through ratepayer-subsidized programs such as low-income assistance and energy conservation measures, and they reward the utilities with excessive returns).

As Mr. Moul recommends that the allowed RoE be set at 11.20 percent, which has an implied equity risk premium that exceeds 8.2 percent, I conclude that Mr. Moul has not reflected the risk reduction impacts of the adoption of weather normalization and rate decoupling mechanisms, but in fact has increased the implied risk premium above historical norms.

b) I have not reviewed the rate structures of the firms included in Mr. Moul's Gas Group.

c) With a "real time" weather normalization mechanism and no deadband as proposed by UGI Gas, the volumetric rate paid by Rate R/RT and N/NT customers for delivered gas will necessarily vary from month to month. In the current rate mechanism, the base rates volumetric charge is constant from month-to-month, save for the effects of the DSIC.

d) The specific documents that I relied upon in responding to this interrogatory are attached to the responses or referenced with URLs. My responses also rely on my academic training in economics and finance, as well as my experience in utility rate proceedings in the past thirty years.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2021-3030218**
	:	
UGI UTILITIES, INC. (Gas Division)	:	
	:	

VERIFICATION

I, Robert D. Knecht, hereby state that the facts set forth in my Rebuttal Testimony labelled OSBA Statement No. 1-S and associated Exhibits RDK-S1 and RDK-S2 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: May 27, 2022

Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2021-3030218**
	:	
UGI Utilities, Inc. – 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).

Administrative Law Judge Joel H. Cheskis
Administrative Law Judge Gail Chiodo
Pennsylvania Public Utility Commission
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
jcheskis@pa.gov
gchiodo@pa.gov

Laura J. Antinucci, Esq.
Mackenzie C. Battle, Esq.
Christy M. Appleby, Esq.
Darryl A. Lawrence, Esq.
Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101
lantinucci@paoca.org
mbattle@paoca.org
cappleby@paoca.org

Carrie B. Wright
Prosecutor
Bureau of Investigation and Enforcement
PA Attorney ID No. 208185
(717) 783-6156
carwright@pa.gov

Joseph L. Vullo, Esquire
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com

Joseph Sohn
1409 Girard Avenue
Wyomissing, PA 19610
gzeppe1@comcast.net

Kent D. Murphy, Esq.
Michael S. Swerling, Esq.
Timothy K. McHugh, Esq.
UGI Corporation
460 North Gulph Road
King of Prussia, PA 19406
murphke@ugicorp.com
swerling@ugicorp.com
mchught@ugicorp.com

Garrett P. Lent, Esq.
Devin T. Ryan, Esq.
Lindsay A. Berkstresser, Esq.
David B. MacGregor, Esq.
Post & Schell, P.C.
glent@postschell.com
dryan@postschell.com
lberstresser@postschell.com
dmacgregor@postschell.com

Francis J. Riviello
609 Moosic Road
Old Forge, PA 18518
mjriviello@icloud.com

Elisabeth Lynch
210 Poplar Lane
Mill Hall, PA 17751
fenrivers1@yahoo.com

Paula Mercuri
3 Villa Drive
Moosic, PA 18507
qwilliams22@gmail.com

Paul Forlenza
128 Saddle Ridge Drive
Dallas, PA 19612
prf2324@comcast.net

Karen O. Moury, Esquire
Eckert Seamans Cherin & Mellott, LLC
213 Market Street, 8th Floor
Harrisburg, PA 17101
kmoury@eckertseamans.com

John W. Sweet, Esq., PA ID: 320182
118 Locust Street
Harrisburg, PA 17101
pulp@pautilitylawproject.org

Annette Miraglia
349 Rutter Avenue
Kingston, PA 18704
a.miraglia@hotmail.com

/s/ Steven C. Gray

DATE: May 27, 2022

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

BEFORE THE
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400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
jcheskis@pa.gov
gchiodo@pa.gov

Laura J. Antinucci, Esq.
Mackenzie C. Battle, Esq.
Christy M. Appleby, Esq.
Darryl A. Lawrence, Esq.
Office of Consumer Advocate
555 Walnut Street
Forum Place, 5th Floor
Harrisburg, PA 17101
lantinucci@paoca.org
mbattle@paoca.org
cappleby@paoca.org

Carrie B. Wright
Prosecutor
Bureau of Investigation and Enforcement
PA Attorney ID No. 208185
(717) 783-6156
carwright@pa.gov

Joseph L. Vullo, Esquire
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com

Joseph Sohn
1409 Girard Avenue
Wyomissing, PA 19610
gzeppe1@comcast.net

Kent D. Murphy, Esq.
Michael S. Swerling, Esq.
Timothy K. McHugh, Esq.
UGI Corporation
460 North Gulph Road
King of Prussia, PA 19406
murphke@ugicorp.com
swerling@ugicorp.com
mchught@ugicorp.com

Garrett P. Lent, Esq.
Devin T. Ryan, Esq.
Lindsay A. Berkstresser, Esq.
David B. MacGregor, Esq.
Post & Schell, P.C.
glent@postschell.com
dryan@postschell.com
lberstresser@postschell.com
dmacgregor@postschell.com

Francis J. Riviello
609 Moosic Road
Old Forge, PA 18518
mjriviello@icloud.com

Elisabeth Lynch
210 Poplar Lane
Mill Hall, PA 17751
fenrivers1@yahoo.com

Paula Mercuri
3 Villa Drive
Moosic, PA 18507
qwilliams22@gmail.com

Paul Forlenza
128 Saddle Ridge Drive
Dallas, PA 19612
prf2324@comcast.net

Karen O. Moury, Esquire
Eckert Seamans Cherin & Mellott, LLC
213 Market Street, 8th Floor
Harrisburg, PA 17101
kmoury@eckertseamans.com

John W. Sweet, Esq., PA ID: 320182
118 Locust Street
Harrisburg, PA 17101
pulp@pautilitylawproject.org

Annette Miraglia
349 Rutter Avenue
Kingston, PA 18704
a.miraglia@hotmail.com

/s/ Steven C. Gray

DATE: July 5, 2022

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