COMMONWEALTH OF PENNSYLVANIA

August 24, 2018

E-FILED

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

Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. / Docket No. R-2018-2647577

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 Direct Testimony and Exhibits, labelled OSBA Statement No. 1, with Exhibits IEc-1 through IEC-3, Rebuttal Testimony and Exhibits, labelled OSBA Statement No. 1-R, with Exhibits IEc-R1 and IEc-R2, and Surrebuttal Testimony, labelled OSBA Statement No 1-SR, on behalf of the OSBA, in the above-captioned proceeding.

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

Sincerely,

Sharon E. Webb
Assistant Small Business Advocate
Attorney ID No. 73995

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

COMMONWEALTH OF PENNSYLVANIA

June 7, 2018

The Honorable Jeffrey A. Watson
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place, Suite 220
301 5th Avenue
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. / Docket No. R-2018-2647577

Dear Secretary Chiavetta:

Enclosed please find the Direct Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1, with Exhibits IEc-1 through IEc-3, on behalf of the Office of Small Business Advocate, in the above-captioned proceedings.

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

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

Sincerely,

Daniel G. Asmus
Assistant Small Business Advocate
Attorney ID No. 83789

Enclosures
cc: Robert D. Knecht
Parties of Record

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	**Docket No. R-2018-2647577**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Direct Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

C&I Network Costs
Cost Allocation
Revenue Allocation
Rate Design

Date Served: June 7, 2018

Date Submitted for the Record: July 26, 2018

DIRECT TESTIMONY OF ROBERT D. KNECHT

I. <u>Witness Identification and Summary of Conclusions</u>

Q. Mr. Knecht, please state your name and briefly describe your qualifications.

A. My name is Robert D. Knecht. I am a Principal of Industrial Economics, Incorporated ("IEc"), a consulting firm located at 2067 Massachusetts Avenue, Cambridge, MA 02140. I specialize in the economic analysis of basic industries. As part of my consulting practice, I have prepared analyses and expert testimony in the field of regulatory economics on a variety of topics. I obtained a B.S. degree in Economics from the Massachusetts Institute of Technology in 1978, and a 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"). 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 IEc-1.

I submitted testimony in the base rates proceedings involving Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company") in 2008 (Docket No. R-2008-2011621), 2010 (Docket No. R-2009-2149262), 2011 (Docket No. R-2010-2215623), 2012/2013 (Docket No. R-2012-2321748), 2014 (Docket No. R-2014-2406274), 2015 (Docket No. R-2015-2488056) and 2016 (Docket No. R-2016-2529660). I also submitted testimony in a variety of Section 1307(f) and other proceedings involving the Company over the past decade.

Because the Company's cost allocation and rate design proposals in this proceeding are, to a large extent, conceptually consistent with those posited in the Company's last three base rates proceedings, this testimony draws significantly on my testimony in those proceedings.

Q. Please describe your assignment in this matter.

A. The OSBA requested that I review the Company's filing in this proceeding to evaluate whether the rates proposed for small business customers are consistent with sound economics and regulatory principles. My analysis focuses primarily on issues of cost allocation, revenue allocation and rate design. My evaluation of Columbia's filing does not constitute an exhaustive review. If I have not addressed a particular issue, it cannot be inferred that I agree with Columbia's proposal for that topic.

Q. Please summarize the conclusions from your review.

A. My conclusions are as follows:

1. To the extent that the Commission has not already resolved this issue, the Company's proposal to implement a fixed commercial and industrial network ("C&I Network") to provide daily metering has not been economically justified, and the project should be deferred until a full economic evaluation has been completed. At a minimum, the C&I Network should not be expanded to include customers in the small general service classes beyond the scope contemplated in the settlement of the Company's last base rates case.

2. I have not prepared a complete and independent alternative to the Company's allocated cost of service studies ("ACOSSs") in this proceeding, although I rely on simulations of ACOSS models that exclude costs for the C&I Network. I also reiterate a number of recommended improvements that Columbia should try to make to its cost allocation methods. It must be recognized that the Company's two cost allocation methodologies produce a range of cost allocation results that render the cost allocation analysis all but useless for revenue allocation purposes, unless some arbitrary average is applied to these methods.

3. In this testimony, I develop a revenue allocation calculation based on a weighted average of the two Company cost allocation methods and value of service considerations. Although I use a very different approach than that employed by the Company, my revenue allocation proposal for the small business rate classes is, in aggregate, not substantially different from that proposed by the Company

4. The Company's proposed changes to the tariff design for the small general service classes are reasonable and consistent with the ACOSS results, at the Company's full proposed revenue requirement. If the Commission reduces the overall proposed rate increase, the tariff charge increases should be scaled back.

5. The Company's proposal to implement a full rate decoupling mechanism for the Residential class should be deferred pending ongoing Commission deliberations and pending legislation regarding alternative ratemaking methods.

Q. Please provide some background regarding the Company's filing, in comparison to its last three base rates proceedings.

A. Columbia submitted base rates filings in 2008, 2010, 2011, 2012, 2014, 2015, 2016 and now 2018. Prior to 2008, Columbia had not filed a base rates case since 1995. The recent spate of rate cases is generally prompted by a significant mains and services replacement program, undertaken over the past decade. A summary of the base rates filing amounts and settlement rate increases is shown in Table IEc-1 below.

Table IEc-1
Recent Columbia Base Rate Increase Cases

Docket No.	Test Year Ending	Proposed Increase ($mm)	Settlement ($mm)	Settlement Percent
R-2008-2011621	Sep-2008	$58.9	$41.7	71%
R-2009-2149262	Sep-2010	$32.3	$12.0	37%
R-2010-2215623	Sep-2011	$37.8	$17.0	45%
R-2012-2321748	Jun-2014	$77.3	$55.3	72%
R-2014-2406274	Dec-2015	$54.1	$32.5	60%
R-2015-2468056	Dec-2016	$46.2	$28.0	61%
R-2016-2529660	Dec-2017	$55.3	$35.0	63%
R-2018-2647577	Dec-2019	$46.8	–	–

Columbia's relatively large proposed increase in the R-2012-2321748 proceeding was due in part to the switch to using a fully forecasted future test year approach, thereby incorporating nearly three full years of (mostly forecast) capital expenditures in the mains replacement program since the prior base rates case.

Q. How is the balance of your testimony organized?

A. This testimony is organized as follows:

- Section 2 provides a brief overview of Columbia's non-residential rate classes, to provide background to the cost allocation, revenue allocation and rate design issues.

- Section 3 provides my review of the C&I Network issue.

- Section 4 reviews my limited assessment of cost causation and Columbia's ACOSS methods and calculations.

- Section 5 addresses revenue allocation issues.
- Section 6 addresses rate design issues.
- Section 7 addresses the Company's proposal for Residential class revenue decoupling.

2. <u>Review of Columbia's Non-Residential Rate Classes</u>

Q. Before getting into the details of your analysis, please summarize the rate classes under which businesses take service from Columbia.

A. Columbia's tariff has a number of schedules under which non-residential customers take service. These tariff schedules are generally distinguished by size of customer (as measured by annual throughput) and type of service. Service types include the following:

- Sales service, in which customers procure both gas supplies and distribution service from Columbia;
- Retail transportation "Choice" service, in which smaller customers can purchase gas supply from NGSs and purchase both bundled load balancing services and distribution services from Columbia;
- Transportation service, in which larger non-residential customers purchase gas supplies from NGSs, purchase load balancing services as needed from Columbia and/or their NGSs, and purchase distribution service from Columbia.

For cost allocation purposes, Columbia aggregates these disparate rate classes into rate class groups.

In total, the non-residential rate classes represent about 58 percent of Columbia's total throughput, or about 48 million of Columbia's total 82 million Dth in the test year. Customer size varies widely, ranging from small businesses that consume less than 10 Dth per year to very large industrial customers with individual loads exceeding 2.5 million Dth per year.

The following are the non-residential rate class groups specified by Columbia for its cost allocation analysis. Because the Company's abbreviations for the rate class groups are somewhat contradictory, I include descriptive names for these groups.

SGSS/SCD/SGDS ("Small General" or "SGS"): This group consists of three tariff schedules: Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD"), and Small General Distribution Service ("SGDS"). Over the past several base rates proceedings, Columbia has adopted differentiated customer and commodity charges for customers in this class, split between customers with annual consumption above and below 644 Dth. Maximum annual throughput for this class is 6,440 Dth/year. Consistent with recent past practice, the Company separates these two groups for both cost allocation and rate design purposes. For simplicity, I refer to the customers with annual consumption below 644 Dth as "SGS1," and the larger customers as "SGS2."

Within these two rate class groups, SGSS is sales service, SCD is retail "Choice" transportation service and SGDS is regular transportation service.

In the SGS1 group, about three quarters of both customers and load are sales customers. The average SGS1 customer size is about 200 Dth per year, which is a little more than double the size of the average residential customer. Of the shopping customers in this group, about 90 percent are Choice customers. Overall, this class represents about 14 percent of the Company's non-residential throughput.

In the SGS2 group, about 54 percent of customer count and 46 percent of the load relate to sales customers. (As is common, shopping customers tend to be larger on average than non-shopping customers.) Of the shopping customers, retail Choice represent less than 30 percent of the customer count and about 20 percent of the load. In effect, the majority of SGS2 shopping customers use traditional transportation service. The average SGS2 customer size is 1,833 Dth/year, which is about 9 times the size of the average SGS1 customer. Overall, this class represents 19 percent of the Company's non-residential throughput.

SDS/LGSS ("Medium General"): This rate class group includes both sales and transportation service customers, taking service under Rate Schedules LGSS (sales service) and Small Distribution Service ("SDS") (transportation service). Columbia's "Small" designation for the transportation customers in this tariff category is misleading, since the *minimum* throughput is 6,440 Dth per year, matching the *maximum* size requirement for the Small General customers. The maximum annual throughput for this class is 54,000 Dth per year, with an average annual customer throughput of about 16,300 Dth. This rate class group represents about 15 percent of non-residential throughput.

LDS/LGSS ("Large General"): This class includes the larger sales customers in the LGSS class along with the transportation service customers taking service under Rate Schedule Large Distribution Service ("LDS"). Minimum throughput is 54,000 Dth per year, matching the Medium General Service upper limit. Average throughput for these customers is about 230,000 Dth per year. This rate class group represents about 43 percent of non-residential throughput. Some 51 percent of the LDS load is subject to "flex" distribution rates (the same percentage as the last base rates case), set on a negotiated basis below the maximum tariff rate. In this proceeding, the Company does not forecast any future test year sales (LGSS) customers in this category.

MDS ("Mainline"): Customers in this rate class group take service under Rate Schedule Main Line Distribution Service ("MDS").[1] To be eligible for this service, customers must have annual throughput over 27,400 Dth *and* be directly connected to an interstate pipeline (Class I), *or* have a minimum annual demand of 214,600 Dth *and* be located within two miles of an interstate pipeline interconnection (Class II). Because these customers require very little in the way of distribution facilities, and because they are credible "bypass" threats, Columbia uses different cost allocation and rate design methods for this rate class group. The 11 Mainline customers identified by Columbia represent about 10 percent of non-residential throughput.

[1] Columbia's tariff includes a Main Line Sales Service schedule, but no customers currently take service under that schedule.

Consistent with recent practice, the Company does not treat large general sales service ("LGSS") customers as a separate rate class for cost allocation purposes, and it includes those customers with transportation customers of comparable size. As I testified in the last two years, I agree with this approach. Sales customers taking service under Rate LGSS are free to switch to the comparable transportation service schedule, and, generally, vice versa. Thus, it is reasonable that the distribution rates for all customers of a similar size be the same, so as to avoid distorting the decision to shop. Since the distribution rates are the same, there is no need to separately allocate costs. Moreover, the total load associated with Rate LGSS is relatively small. **3.**

C&I Network

Q. **Please provide your understanding of the background for the C&I Network proposal advanced in this proceeding.**

A. In the Company's last base rates proceedings, the "NGS Parties" asserted that metering information availability from the Company was insufficient to allow the competitive natural gas suppliers ("NGSs") to balance supplies with customer loads during periods when system gas supplies are constrained (OFO/OMOs). The Company responded to these concerns in the rebuttal testimony of Michele L. Caddell (Columbia Statement No. 15-R at 11 to 25), generally indicating (a) it is the obligation of customers without daily meters to maintain a dedicated phone line to provide usage data to Columbia (who could pass it on to EGSs), (b) it is the EGSs obligation to coordinate with their non-daily-metered customers to obtain usage information, and (c) many of the EGS complaints regarding data availability were not valid as the data was available from the Company if the customer had granted the EGS access to the data. As part of the settlement of that proceeding, the parties agreed that:

> 54.a) Columbia agrees to propose in a non-general tariff filing that all customers eligible to be served on Rate Schedules SDS, LDS and MLDS [Small Distribution Service, Large Distribution Service, and Main Line Distribution Service] must have installed Electronic Flow Correctors ("EFC") and telephonic equipment to transmit daily usage information to Columbia. Columbia further agrees to propose that it install, own, operate and maintain all equipment, including telephonic or similar technology, provided that Columbia is granted rate recovery of reasonable and prudent capital and operating and maintenance costs to own, operate and maintain the capability to obtain daily

> information from such customers. To the extent that any associated costs will not be rate based, Columbia shall be permitted to seek to create a regulatory asset for such costs and propose to recover them in its next base rate case. All Parties retain their rights to support or oppose such proposal in the non-general rate filing. Issues related to cost allocation and rate recovery of the costs associated with this equipment will be addressed in the Company's next base rate proceeding.

The Company made such a proposal at Docket No. R-2017-2586190 in the form of Supplement 255. As I interpret the tariff supplement, the tariff now requires that the Company install at its expense equipment for daily metering for all customers over 6,440 Dth in annual throughput.[2]

In its filing, however, the Company retained its view that its existing equipment and systems did not inhibit NGS compliance with balancing requirements. In particular, the Company indicated that in the cases when the existing systems could not provide information directly, NGSs could have access to daily consumption information by coordinating with their customers.[3]

In the Supplement 255 filing, the Company provided a cost estimate for implementing this equipment at $4.3 million in one-time capital, $1.3 million in one-time O&M, $0.136 million in annual incremental capital and $1.4 million in annual O&M, and argued that this was less costly than a telemetering option. No cost-benefit analysis was included in the filing. Similarly, the filing indicated that customers were not consulted. Moreover, because cost recovery was not contemplated in that proceeding, customers could not have been aware of the bill impact of the proposal.

The Company also appears to have proposed at that time that all customers with annual load above 5,000 Dth should be given this metering, which implied that customers beyond those contemplated in the settlement in the SGS2 rate class group would be required to

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[2] Paragraph 15.7 was amended to include the following language: *"The Company shall install, at its expense, equipment necessary to provide daily measurement at any customer premises where the customer's usage exceeds 64,400 therms during the prior twelve months ending October. The daily usage will be available for the customer, his agent or any other customer authorized party using a secure internet address."*

[3] Supplement 255, Statement of Reasons at 3-4. Docket No. R-2017-2586190.

have these meters. However, the filing provides no indication that SGS2 customers (or even Rate LGSS customers, for that matter) would be affected by this proposal, nor is there any reference to the 5,000 annual Dth limit in the supplement.

Based on documents from the Commission's website, no party other than the Company participated in this proceeding.

Finally, the Company also proposed to create a regulatory deferral account for recovery of the costs of the equipment, with the issue of rate recovery to be deferred until the next base rates case proceeding.

The filing was approved by Commission Order entered March 16, 2017. The Commission stated:

> Upon review of Tariff Supplement No. 255 to Columbia's Tariff-Gas Pa. P.U.C. No. 9, we find that the proposed modifications contained therein do not appear to be unlawful, unjust, unreasonable, or contrary to the public interest. We agree with Columbia that the tariff changes mandating the installation of daily read measurement equipment for certain classes are needed to provide for the daily transmission of customer usage data in a timely manner.

Q. What issues has the Company brought forth in this proceeding on this issue?

A. The Company raises four issues:

- The Company updates the cost estimates for the C&I Network to reflect a new vendor for the equipment;
- The Company includes the costs for the C&I Network in its fully projected future test year revenue requirements, and allocates the costs among the rate classes based on the number of customers for whom the equipment will be installed (including flex rate customers);
- The Company proposes a tariff recovery mechanism for the costs, in the form of a separate per-bill monthly charge denoted the "C&I Network Charge" for customers for whom the equipment will be installed but who are not flex rate customers;

- In light of the cost increases, the Company proposes that the parties and the Commission conduct an "examination of the cost and benefit of proceeding with the system before substantial investment of the system is undertaken." (Columbia Statement No. 10 at 26).

Q. Please summarize the change in forecast costs.

A. Table IEc-2 below provides the forecast cost comparison:

Table IEc-2 C&I Network Costs Estimates $mm		
	Original	**Updated**
Up-Front Capital	$4.3	$6.0
Up-Front O&M	$1.3	$0.7
Annual Incremental Capital	$0.14	$0.20
Annual O&M	$1.4	$1.2
Sources: Columbia Statement No. 10.		

Q. Do you agree with the Company's view that this investment should be subject to a cost-benefit evaluation?

A. I do. In my view, the need for this equipment was not clearly demonstrated at Docket No. R-2017-2586190, as the Company continued to believe that much lower cost alternatives (such as NGSs coordinating with their customers) could address the purported problems. Moreover, as noted above, no cost-benefit analysis was undertaken, no customer consultations were undertaken, and no customer impact evaluations were performed. (As is often the case, a capital project will often not appear unreasonable until it comes time to determine who will pay for it and how.) Based on the Company's proposal in this proceeding, I calculate that the impact of the charge for small Rate SDS customers will be about 60 cents per Dth, which would represent an increase in distribution rates of some 21 percent, before the rest of the Company's rate increase is applied. For the 5,000 Dth per year SGS2 customers, the impact would be 77 cents per Dth. This would certainly appear to be a significant cost to accommodate NGSs who are unable to coordinate with their customers..

Nevertheless, I recognize that the Commission may deem this matter to be fully resolved in Matter R-2017-2586190, and that it expects the Company to implement the C&I Network pursuant to that decision.

Q. Has the Company submitted a cost-benefit analysis?

A. Not to my knowledge. For that reason, I recommend that this proposal be deferred until the Company prepares a full cost-benefit of this proposal, with a reasonable comparison to other less capital-intense alternatives by which NGSs and their customers could better share metering information.

Q. If the Commission determines that the C&I Network is already approved, do you agree that customers in the small general service classes with annual load above 5,000 Dth should be required to have (and pay for) this equipment?

A. No. The settlement of the Company's last base rates proceeding did not contemplate installing this equipment for those customers. As such, there was no reason for parties to believe that the Company's filing at Docket No. R-2017-2586190 would affect SGS customers. Moreover, as noted earlier, none of the impact evaluations in the Company's filing at that docket contemplated effects on SGS customers, and the approved tariff language does not specify the usage level which would trigger this required equipment. As such, I (as a non-lawyer) would generally conclude that these customers did not receive any reasonable warning that they would be assuming the cost for this equipment in that proceeding. Finally, as I noted earlier, at up to 77 cents per Dth, the costs for these customers is unreasonable and excessive. It his highly doubtful that NGSs can consistently provide that kind of cost savings to their SGS customers.

Q. If the Commission approves the C&I Network project, do you agree that the equipment and the C&I Network Charge should apply to all customers who meet the volume requirement, including sales, Choice and transportation customers?

A. No. The only economic rationale offered for this project is to provide NGSs with information that will allow them to comply with OFO/OMO balancing requirements.

Neither sales nor Choice customers require such balancing services, and they will not benefit from this equipment. This conclusion is consistent with the settlement language from the last base rates case, in which the classes targeted for this equipment were explicitly limited to transportation service classes (SDS, LDS, and MLDS).

As such, the Company's proposal to apply the C&I Network Charge to large SGSS sales customers, SCD Choice customers and LGSS sales customers is not consistent with the settlement, and simply makes no sense. If a sales customer decides to switch to transportation service, it should simply be required to pay for the metering that is deemed necessary to allow NGSs to comply with OFO/OMO requirements.

4. <u>Cost Allocation</u>

Q. What is the purpose of a utility's ACOSS?

A. The most important criterion for setting regulated utility rates is the cost incurred by the utility for providing the service.[4] To assign costs to specific customers, utilities aggregate customers into rate classes, within which the customers have similar load sizes, seasonal consumption, peak demand patterns, and other characteristics. An ACOSS is an analytical tool with which the utility's total cost (or "revenue requirement") is allocated among each of the rate classes. These allocated costs are then used as a key input in determining the total revenues that the utility plans to recover from each rate class through tariff rates.

In using the results from an ACOSS to develop class revenue requirements, utilities and regulatory authorities usually have a longer-term goal of moving the revenue recovered from each class as close as possible to the costs allocated to that class. That is, in each proceeding, regulators try to move class revenues more into line with cost-based rates. Thus, rate classes whose revenues substantially exceed allocated costs are assigned either relatively low rate increases or rate decreases. Rate classes whose revenues are well below allocated costs are assigned relatively larger rate increases than those classes whose revenues are only slightly below allocated costs.

[4] The Commonwealth Court affirmed this basic principle, referring to cost of service as the "polestar" criterion. <u>Lloyd v. Pennsylvania Public Utility Commission</u>, 904 A.2d 1010, 1020 (Pa. Cmwlth. 2006).

In addition to class revenue requirement issues, an ACOSS can provide useful cost information regarding the specific nature of utility tariff charges. In particular, an ACOSS provides a cost basis for the relative magnitude of the various individual tariff charges, including the customer charge, demand charges and commodity charges.

Q. How does an ACOSS assign costs to the various rate classes?

A. The underlying principle of an ACOSS is that costs are assigned to the rate classes that *cause* the utility to incur those costs. This principle of cost causation is both equitable and economically efficient. It is equitable because costs are borne by those customers who cause them. It is economically efficient because the price signal for consumption from a particular rate class is reasonably consistent with the cost incurred by the utility to provide the service. In that way, the consumer receives the correct price signal for determining whether he should purchase more or less utility service. In effect, the consumer balances the value that he receives from the purchase of that service against the utility's cost of providing the service.

Q. What is the Company's approach to cost allocation in this proceeding?

A. With its filing, the Company presented three detailed cost allocation studies, in Exhibit 111 Schedules 1, 2 and 3.

Q. Why does the Company present three different cost allocation studies?

A. For gas distribution utilities, the issue of the classification and allocation of mains costs is often contested in regulatory proceedings.[5] This debate has a significant impact on rate design for a number of reasons. First, mains costs are "joint use" costs, meaning that they cannot be directly assigned to a particular customer or customer class, and must be allocated using some reasonable methodology. Second, mains represent a very large percentage of a gas utility's overall rate base, thereby determining each class' share of

[5] In a traditional cost allocation study, the "classification" step involves segregating costs into basic cost causation categories, generally energy/commodity-related, peak demand-related, excess demand-related, or customers. "Allocation" is the step which spreads the classified costs among customers or customer classes, based on some reasonable measure of the classification factor. For example, gas utility distribution costs classified as peak demand-related are typically allocated using some measure of customer class peak demand, such as design day demand or contract demand.

income tax and return on capital costs. Moreover, given the nature of ACOSSs, the allocation of mains costs also drives the allocation of a large percentage of the O&M costs. Third, the analytical models used by cost allocation experts can vary considerably in their impact on the percentage of mains costs assigned to each class. And fourth, the cost allocation methodology for mains can have a significant impact on the ultimate rate design for the recovery of costs within each rate class, notably with respect to the magnitude of the customer charge.

Rather than take a firm position on this debate, the Company essentially picks two methods which it asserts lie at opposite ends of the philosophical spectrum, and presents the results of both. These studies are denoted the CD ACOSS (Exhibit 111 Schedule 1) and the P&A ACOSS (Exhibit 111 Schedule 2). The third ACOSS (Exhibit 111, Schedule 3) is a simple average of the two. The differences between these three ACOSSs are related only to the issue of mains cost allocation – all other allocations are methodologically the same in the three studies.

Q. Can you comment briefly on the issue of mains cost classification and allocation?

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

Having stated that, however, it is not easy to develop an analytical model capable of reflecting these cost causation factors reasonably. Ideally, the cost of any particular segment of main would only be allocated to those specific customers who are served downstream from that segment.[6] In practice, however, undertaking such an analysis could

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[6] Even allocating the costs for a single main segment when the customers served by the segment are known is not an obvious matter. Economics theory indicates only that a subsidy-free allocation method is one in which each customer, or any group of customers, will be allocated costs that fall below the stand-alone cost of service, and which exceed the incremental cost of service. With the significant scale economies in mains construction costs, these restrictions still leave a fairly wide range of subsidy-free allocation methods. However, it can be demonstrated that both methods used by the Company in this proceeding (minimum system and P&A) can produce results that lie outside that range. By way of contrast, the 100 percent demand and zero-intercept methods will generally produce results that do not violate these criteria.

be detailed, costly and time consuming. Few utilities attempt such an undertaking. While Columbia is no exception to this rule, Columbia's ACOSS methodology takes a step in that direction in this proceeding, by sub-dividing its mains costs by size/operating pressure, and allocating each group of mains only to customers who take service from those mains. Also, in the last base rates proceeding, Columbia indicated that its information systems have much of the information for allocating mains costs on a pipe segment by segment basis, only to downstream customers. I again encourage Columbia to investigate whether it can develop such an approach in the future, and in that way avoid the wildly disparate results that come from the traditional allocation methods.[7]

Given the expansion of GIS software and modeling technology, it is somewhat surprising that utilities and regulators do not know which mains service which customers, and are therefore forced to rely on costing methods which produce wildly different results.

Q. If a detailed systems assessment is not undertaken, what are the "traditional" methods that apply to mains cost classification and allocation?

A. Absent a detailed assessment, various analytical models are used. These methods generally focus on the following questions:

- Are mains costs causally related to the number of customers? And, if so, how should the "customer component" of mains costs be derived?

- How should mains costs that are not causally related to number of customers be allocated among the various rate classes?

Regarding the first question, the common sense argument (to which I generally subscribe) is that more footage of mains must be installed to interconnect many small customers than

[7] I note that a few utilities pursue such a detailed approach. For example, at Docket No. Docket R-00953297, UGI Utilities, Inc. (Gas Division) put forward a Network Analysis cost allocation approach, in which costs for each main segment were allocated to downstream customers in proportion to customer design day demands. (Sadly, that utility chose to abandon this approach for smaller customers in its most recent base rates proceeding at Docket No. R-2015-2518438.) Also, Alberta electric utility Aquila Networks Canada put forward a distribution cost allocation proposal in which allocated costs were derived at a detailed level for a sample of electric distribution feeders, in which distribution costs were allocated only to the specific customers downstream of each asset in proportion to on-peak load. (See Alberta Energy and Utilities Board (now Alberta Utilities Commission) Decision 2003-019.)

to connect one large customer. This common sense argument is supported by some aggregate industry statistical analysis.[8] As such, mains footage is causally related to the number of customers, and therefore mains costs are partially customer-related. However, some experts disagree, and conclude that no component of mains costs is causally related to customer count. Moreover, even if there is a statistical correlation between mains footage and number of customers, none of the traditional mains cost classification methods reasonably reflects that relationship.[9]

Relatively recent Commission precedent indicates that the Commission has rejected the use of a customer component for gas distribution utilities.[10] However, more recent Commission precedent for electric distribution utilities, where the conceptual arguments regarding cost causation are similar, supports the recognition of a customer component for joint-use distribution plant allocation.[11]

In this proceeding, the Company's filed CD ACOSS includes a customer component for mains costs, while the P&A ACOSS does not.

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

[9] See pre-filed evidence of Robert D. Knecht, Dossier R-3867-2013, 26 February 2015, Exhibit IEc-3, http://publicsde.regie-energie.qc.ca/projets/235/DocPrj/R-3867-2013-C-ACIG-0028-Preuve-RappExp-2015_02_26.pdf .

[10] In a case involving PPL Gas at Docket No. R-00061398, the Commission approved an allocation of all mains costs using a variant on the A&E allocation method advanced by the utility expert witness. In that proceeding, the approved weighting was 40 percent to average demand and 60 percent to excess demand. This weighting was not based on system load factor. PA PUC et al. v. PPL Gas Utilities Corporation, R-00061398, Order Entered February 8, 2007, page 112 – 114. Also, in a case involving the Philadelphia Gas Works ("PGW") at Docket No. R-00061931, PGW proposed to classify some mains costs as customer-related and the balance as demand-related, and proposed to allocate demand-related costs using a peak demand allocator. However, the Commission concluded that no mains costs should be classified as customer-related, and that mains costs should be allocated using a variant of the A&E allocation method advanced by the Office of Trial Staff expert. In the PGW proceeding, the approved weighting was 50 percent to average demand and 50 percent to excess demand. This weighting was also not based on system load factor. See PA PUC v. Philadelphia Gas Works, R-00061931, Recommended Decision, July 24, 2007, page 63, and PA PUC v. Philadelphia Gas Works, R-00061931, Order Entered September 28, 2007, page 80.

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

If a customer component is included, the basic approaches involve deriving a customer component of costs based on the cost associated with a theoretical system with little or no load carrying capability. The demand-related component of cost is then calculated as the cost to expand that "minimum system" to the actual existing system.

One basic approach for deriving the minimum system is to base the customer component of mains cost as if entire system if it were built using only the minimum diameter main in current use (e.g., a 2-inch diameter main). This is, in fact, the method the Company uses in its CD ACOSS. However, this method is often criticized for including an implied demand-related component in the minimum system, because the minimum system of 2-inch pipe has some load carrying capability.

In the alternative, some experts generally prefer to use a method in which the customer component is based on a minimum system with a zero-diameter pipe. This approach is denoted a zero-intercept ("ZI") classification method. In this method, the cost of a zero-diameter pipe is estimated statistically using the utilities' actual costs for various pipe sizes. This approach avoids the problem of the load carrying capability of the minimum system, since a zero diameter pipe has no load carrying capability. This approach, however, is often subject to statistical issues and data problems that do not arise with a traditional minimum system.

In addition, some experts attempt to address the load carrying capability of the minimum system by adjusting the allocation of demand-related costs.[12] However, any such adjustment necessarily requires arbitrary adjustments to demand allocators, since it is very difficult to evaluate just what the load carrying capability of a system consisting solely of 2-inch mains actually is for each customer on the system.

In this proceeding, in its CD ACOSS, the Company uses a minimum system approach, based on 2-inch mains, with no adjustment to the demand allocators. The Company applies

[12] Unfortunately, I know of no theoretically reasonable method for deriving the load carrying capability of the minimum system.

the minimum system approach to both its low-pressure and medium-pressure systems. Transmission mains are allocated on a 100 percent demand basis.

Finally, there is a debated issue as to how the non-customer component or "demand component" of mains costs should be allocated. Conceptually, some experts (myself included) argue that, because mains diameters must be sized to meet peak demand, the demand component of mains costs should be allocated only on peak demand. Other experts advocate for a weighting of average demand (arithmetically equivalent to throughput) and excess demand (peak demand minus average demand), which is known as an average-and-excess ("A&E") allocator, while others support a weighting of average demand and peak demand, which is known as a peak-and-average ("P&A") allocation factor.

Relatively recent Commission precedent for gas utilities in Pennsylvania generally supports the use of an A&E allocation method (albeit a non-traditional version of the A&E method), while for electric utilities Commission precedent supports the use of a peak demand allocator.

In this proceeding, the Company uses a peak demand allocator in the CD ACOSS, and a P&A allocator in the P&A ACOSS. In effect, neither Company method is consistent with the most recent Commission precedent on this issue.

Q. Do the Company's methods encompass the full range of potential cost allocation results that may be offered by cost allocation professionals?

A. Probably not. As evidenced in the Company's last base rates case, the Company's two cost allocation studies do not span the full range of possible options. The Company's P&A method segregates mains between larger diameter, higher pressure mains and mains that are either small diameter or operated at low pressure. Some experts disagree that it is appropriate to segregate mains in this fashion, and argue that all joint use mains be allocated as an integrated system.[13] I refer to this approach as the "Traditional P&A" method in this

[13] See, for example, OCA Statement No. 3 at Docket R-2016-2529660 (Columbia's last base rates case), pages 7-8. In general, Commission precedent supports this view.

testimony. If the only objective is to present the range of possible cost allocation methods, the Traditional P&A is a more extreme approach than the Company's P&A method.

Q. Why do the CD ACOSS and the Traditional P&A ACOSS present the extremes of mains cost allocation philosophy?

A. The CD ACOSS is most favorable to large customers. It includes a customer component of costs, which recognizes system economies of scale associated with serving large customers. Customer-related costs are almost entirely assigned to smaller customers, resulting in relatively higher costs for those classes. Moreover, the CD method uses a minimum system method for classifying costs as customer related, which produces a larger customer component than does the zero intercept approach, thereby assigning more costs to small customers. Finally, the CD ACOSS uses a peak demand allocator. As larger customers are less "peaky" than smaller customers, a peak demand allocator reduces the allocation of costs to larger, higher "load factor" customers.

In contrast, the Traditional P&A ACOSS is generally most favorable to the smallest customers for three reasons. First, the P&A method has no customer component at all, which is favorable to the smallest customers, as economies of scale are not reflected in mains cost allocation. Second, because smaller and low-pressure mains are allocated to all customers, the Traditional P&A approach is generally more favorable to smaller customers than the Company's approach, which does not allocate any of these mains costs to larger customers. Third, the Traditional P&A method allocates costs substantially based on average demand. Because small customers tend to be more weather sensitive than larger customers and therefore have relatively less average demand per unit of peak demand (i.e., a lower "load factor"), the P&A method assigns less costs to smaller customers than other methods which rely more heavily on peak demand.

Q. Have you prepared a full independent version of a cost allocation study in this proceeding?

A. No, I have not. However, over the years, I have developed a working version of the Company's model, and I use that for my analysis (beginning with a near-replication of the

Company's results for the CD and P&A ACOSS models).[14] For the reasons discussed above, I simulated these models without C&I Network costs.[15] To maintain consistency with the Company's revenue requirement and provide for comparable revenue allocation comparisons, I replace the Company's provision for the C&I Network costs with placeholder cost items that are all allocated in proportion to total allocated costs.

In the Company's 2012 base rates proceeding, I conducted a detailed review and developed independent ACOSSs. In the 2014 and 2015 cases, the Company addressed many of the issues that I identified in that analysis, although it did not address some others. In the last two proceedings, the Company has generally followed those practices, although it has made a number of modest improvements.

For this proceeding, I conducted some modest follow-up analysis for key cost areas, and I offer the following recommendations for future cost allocation analysis:

1. As noted above, the Company should investigate whether it can develop a cost allocation methodology that assigns mains costs on a segment-by-segment basis only to customers downstream from that segment.

2. If a main-by-main cost allocation methodology can eventually be adopted, the Company will need to determine how to specify the cost of each main segment. In its current minimum system approach, the Company simply uses gross book cost, unadjusted for either inflation or accumulated depreciation. In contrast, I would recommend that a reasonable replacement cost measure be used to develop the cost for each main segment. Most utilities incorporate a measure of

[14] In replicating the Company's analysis, I was able to adopt much but not all of the rounding approach used in the Company's study, leading to small differences. While the Company's method does not appear to cause major distortions, it sometimes results in observable differences, particularly for classes that represent a small share of some costs, such as customer costs for the MDS class. It is unclear why the Company retains this rounding technique in light of these modest distortions.

[15] In reviewing the Company's calculations, I noted that, in incorporating the C&I Network costs into the ACOSS, the Company does not appear to include the allocated costs for gross plant, accumulated depreciation and annual depreciation expense in its totals, but in fact implicitly allocates those costs using traditional allocators. Similarly, the Company excludes C&I Network costs from some of its overall plant and O&M allocation factors. I assume that this was not intentional. Thus, if the Commission does approve C&I Network costs in the revenue requirement, I suggest the Company review its calculations in this respect.

replacement cost into the mains classification analysis, by adjusting historical book costs for inflation, typically using Handy-Whitman gas mains cost construction indices.[16] However, in light of the substantial technological changes, I recommend also that such a replacement cost analysis recognize that much of the existing cast iron and steel mains would be replaced with plastic mains, generally at lower cost.

3. After mains, services costs represent the largest component of the Company's distribution rate base. Unfortunately, Columbia's cost allocation method for services costs continues to suffer from limited data availability, although the Company has addressed one of the concerns I raised in the past. Specifically, the Company has improved the allocation of services with diameters in excess of 3 inches, better reflecting the higher cost of larger diameter services. However, the vast majority of the Company's services costs are still lumped together into a large group of all services with diameters at or below 3 inches. For these services, the Company does not have cost accounts delineated by diameter, and therefore cannot allocate these on any basis other than customer count. Thus, while the under-3 inch services may exhibit a cost pattern similar to that for over-3 inch services, the data are not sufficient to reach a conclusion. Given the large cost implications for this account, Columbia should develop a more accurate approach.

4. For the reasons discussed further below, the Company should consider segregating flex rate customers for cost allocation purposes, particularly in the Large General Service (LDS/LGSS) class, which would allow for a better evaluation of the cost basis for regular tariff rates.

However, because I generally do not have sufficiently detailed data to make any of these modifications myself, and because the Company's approach should generally encompass the range of established cost allocation practice, I have relied on both of

[16] Based on my review of the Company's responses to interrogatories, it appears that the Company has sufficiently detailed data to adjust cost parameters for cost inflation.

the Company's ACOSS methodologies for my revenue allocation and rate design recommendations in this proceeding. I recommend only that the Company continue to look for ways to improve these aspects of its cost allocation method in future base rates proceedings.

Q. What are the implications of the various ACOSS methodologies that you reviewed in this testimony?

A. Table IEc-3 below shows the implications of the various ACOSS methodologies discussed in this testimony. These values are based on my simulations of the ACOSS models, adjusted as discussed above. Also, because it is a significant issue for revenue allocation, I split the Large General class into regular rate and flex rate customers.[17]

[17] While other rate classes have some flex rate customers, these customers have a material impact on revenue allocation only for Rate LDS.

Table IEc-3 Summary of ACOSS Implications ($000)							
	Total	Residential	SGS1	SGS2	Medium General	Large General	MDS
Current Non-Gas Revenues	410,250	303,756	35,051	34,599	17,741	17,899	1,204
CD ACOSS							
Increase to CBR	46,835	69,612	1,779	-11,997	-3,486	-8,012	-1,061
Percent	11.4%	22.9%	5.1%	-34.7%	-19.6%	-44.8%	-88.1%
P&A ACOSS							
Increase to CBR	46,835	16,791	3,136	833	4,926	22,211	-1,061
Percent	11.4%	5.5%	8.9%	2.4%	27.8%	124.1%	-88.1%
Traditional P&A ACOSS							
Increase to CBR	46,835	187	2,144	1,530	6,775	37,260	-1,061
Percent	11.4%	0.1%	6.1%	4.4%	38.2%	208.2%	-88.1%
Source: Exhibit IEc-2, RDK Workpapers.							

As shown in Table IEc-3, while the three cost allocation philosophies may span the possible range of cost outcomes, they provide little in the way of guidance for cost allocation and rate design. Only the results for the MDS class show a consistent pattern, and then only because mains are directly assigned to that class in all three methods. To a lesser extent, the results for the SGS1 class are also reasonably consistent, with all methods suggesting that a cost-based increase for that class would involve an increase of roughly half to three-quarters of the system average increase. In addition, the three studies suggest that the SGS2 class should either be assigned a significant rate decrease, or an increase well below system average.

After that, the results are all over the map. Rate increases for the residential class needed to bring revenues into line with allocated cost range from $0.2 million (0.1%) to $69.68 million (22.9%), a range that is wider than the entire increase proposed by the Company. Even more variable, the rate changes needed to move revenues for the Large General class into line with allocated cost range from a *reduction* of nearly 45 percent to an increase of over 200 percent.

Moreover, when the impact of flex rate customers is considered, the lack of guidance in the cost allocation study simply gets worse. Table IEc-4 below shows the results from Table IEc-3 for the Large General class, split between regular and flex rate customers. As a caveat, because detailed cost parameters for flex rate customers are not available, I segregated the allocated costs within the class based on my estimate of the share of current full tariff rate revenues, which I estimate at 43.9 percent for flex rate customers and 56.1 percent for regular rate customers.[18] As such, the results below are imprecise, but I believe illustrative.

Table IEc-4
Summary of ACOSS Implications: Large General Class ($000)

	Large General	Regular Rate	Flex Rate
Throughput (MDth)	20,652	10,103	10,549
Current Revenues	17,899	13,878	4,021
CD ACOSS			
Increase to CBR	-8,012	-8,335	323
Percent	-44.8%	-60.1%	8.0%
P&A ACOSS			
Increase to CBR	22,211	8,609	13,602
Percent	124.1%	62.0%	338.3%
Traditional P&A ACOSS			
Increase to CBR	37,260	17,046	20,214
Percent	208.2%	122.8%	502.7%

Source: RDK Workpapers.

[18] Because the Company applies such substantially different rates to flex rate and regular rate Large General Service customers, it may wish to consider segregating the class on that basis for cost allocation purposes in future rate proceedings. Based on my review of the Company's analysis, the key cost parameters should generally be available on a customer-by-customer basis for the Large General Service class, and thus segregating the class should be relatively straightforward. I believe this approach would also clarify revenue allocation issue for that class, where increases can be assigned to regular rate customers but not flex rate customers.

As shown in Table IEc-4, the flex rate Large General customers represent about 50 percent of class volume but only 22 percent of the current rate revenues. As such, the revenues from flex rate customers are already substantially reduced from regular tariff rates. Moreover, both ACOSS methods that rely on the P&A approach generally assign costs to the flex rate customers that are four to six times current revenues. Even the CD ACOSS method would imply a material increase for these negotiated flex rate customers. Thus, it must be recognized that if Columbia cannot increase revenues from the flex rate customers without losing them to bypass or alternative fuel, there will be a substantial shortfall from those customers, and that shortfall must be recovered from the rest of the customers. If either P&A method is adopted, this shortfall will be enormous.

5. <u>Revenue Allocation</u>

Q. What is revenue allocation?

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

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

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

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

- the *value of service* principle, which is often used to mitigate rate increases for customers or customer classes with relatively elastic demand.[19]

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

Q. In evaluating the Company's revenue allocation, which aspects of the Company's revenue have you considered in this proceeding?

A. Although this is a base rates proceeding, the Company's ACOSSs and its proof of revenue analyses (Exhibit 103) include all of the Company's revenue. However, the costs and revenues for purchased gas are not the subject of this proceeding, and simply balance out. The rest of the costs incurred by Columbia are the subject matter of this proceeding, and are effectively part of the revenue requirement, the cost allocation and the rate design. Thus, I include all of the costs and revenues except purchased gas costs in my analysis, including costs and revenues related to base distribution rates, Rider USP (universal service), Rider CC, the GPC (gas procurement charge for administrative costs related to utility gas supply), and the MFC (merchant function charge, related to recovery of uncollectibles costs for utility gas sales service). In measuring percentage changes, I also include all non-purchased gas cost revenues.

Q. Please summarize Columbia's proposed revenue allocation in this proceeding.

A. The Company indicates that it subscribes to the principle that rates should be moved into line with allocated costs, subject to rate gradualism considerations. For its cost basis, the Company claims that it generally relies on its Average ACOSS methodology. The Company also proposes not to assign a rate decrease to the MDS class (and in fact includes

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

an increase for the C&I Network), although a decrease would be justified based on allocated costs. In addition, the Company appears to have considered the fact that it cannot impose rate increases on flex rate customers, the vast majority of which take service in the Large General Service class. The Company's revenue allocation proposal is summarized in Table IEc-5 below.

Table IEc-5
Summary of Columbia Revenue Allocation Proposal
($000)

	Total	Residential	SGS1	SGS2	Medium General	Lg Gen Regular	Lg Gen Flex	MDS
Current Revenues	411,841	304,990	35,199	34,719	17,787	13,878	4,021	1,208
Proposed Increase	46,835	37,630	2,381	2,157	2,500	2,125	0	42
Increase%	11.4%	12.3%	6.8%	6.2%	14.1%	15.3%	0.0%	3.5%
Cost-based Increase	46,835	43,201	2,458	-5,582	720	137	6,963	-1,061
Percent	11.4%	14.2%	7.0%	-16.1%	4.1%	1.0%	173.2%	-88.1%

Notes:

1. Revenues include all tariff revenues except gas supply costs.
2. Cost-based increase is rate increase to bring revenues fully into line with allocated cost, based on 50/50 weighting of my CD and P&A simulations of the ACOSS

Source: RDK Workpapers.

As shown, the Company's revenue allocation proposal is not fully consistent with the cost implications for a simple average of its cost allocation studies, even recognizing the need to accommodate flex rate customer shortfalls. In that respect, the revenues from the Large General flex rate customers fall far short of allocated costs, by nearly $7 million. This shortfall is partly offset by the over-recovery from the MDS class of about $1.1 million, for which the Company does not propose a rate decrease. Nevertheless, these impacts imply that higher than cost-based increases are generally necessary from the other rate classes to meet the revenue requirement. However, for the Residential and SGS1 classes, the Company proposes rate increases that are below those necessary to move rates into line with allocated costs. This leaves the remaining classes, namely SGS2, Medium General, and Large General (regular rate) bearing significant rate increases, despite the cost evidence that only minimal rate increases would be justified under the Company's stated cost basis. The case of the SGS2 class is particularly problematic, in that the Company assigns a material increase to that class despite the fact that the class substantially over-recovers costs at current rates.

Thus, it is not entirely clear how the Company developed the revenue allocation proposal for this proceeding. The Company indicates only that its revenue allocation serves to move class revenues closer to allocated costs, but it does not explain how the revenue allocation was developed, nor whether the *progress* toward cost-based rates is consistent across rate classes.[20]

Q. How does the Company's proposal compare to the revenue allocation over the past several base rates proceedings, all of which were resolved by settlement?

A. Table IEc-6 below provides the comparison. Note that I've included the revenue sharing percentages that would result from moving all rates into line with allocated costs under the two ACOSS methods.

[20] The Company evaluates whether progress toward cost-based rates is achieved using the indexed rate of return metric. While I recognize that this metric has long been used by utilities in Pennsylvania, it is a biased measure that can imply that rates are moving into line with allocated costs when basic common sense would indicate otherwise.

Table IEc-6 Revenue Allocation Shares in Recent Columbia Base Rate Cases Measured as a Percentage of the Approved Revenue Increase						
Docket No.	Residential	SGS1	SGS2	SDS/LGSS	LDS/LGSS	MDS
Settlements						
R-2008-2011621	79%	13%		4%	4%	0%
R-2009-2149262	73%	18%		5%	4%	0%
R-2010-2215623	75%	19%		5%	1%	0%
R-2012-2321748	74%	19%		6%	1%	0%
R-2014-2406274	75%	16%		4%	5%	0%
R-2015-2468056	73%	16%		7%	4%	0%
R-2016-2529660	74%	8%	9%	5%	3%	0%
Columbia Proposed at R-2018-2647577						
Proposed	81%	5%	5%	5%	5%	0%
CD ACOSS	149%	4%	-26%	-7%	-17%	-2%
P&A ACOSS	36%	7%	2%	11%	47%	-2%
Sources: Settlement documents from Commission website, RDK workpapers.						

Table IEc-6 generally shows that the Company's proposed allocation of the revenue requirement would produce a sharing that is not substantially different from the settlements of the past seven base rates proceedings. The Company proposes to assign a modestly larger share of the increase to the Large General (LDS/LGSS) rate class and the Residential class, and a lower share to the Small General Service (SGS1 and SGS2) rate classes, presumably reflective of the results of its ACOSS analyses in this proceeding.

Q. Do you agree with Columbia's proposed revenue allocation methodology in this proceeding?

A. No. First, I do not agree with the use of a 50/50 weighting of ACOSS methods for the reasons discussed below. Second, for the reasons discussed above, if the Commission adopts the Company's proposed 50/50 weighting of the CD and P&A ACOSS methods, a very different revenue allocation would be appropriate. If that were the case, no rate increase should be assigned to the SGS2 class, because that class already produce revenues well in excess of allocated cost. In addition, under a 50/50 weighting of cost allocation methods, a materially larger increase should be assigned to the Residential class, with below system average increases being assigned to the SGS1, Medium General and Large General (non-flex) rate classes.[21]

Q. Have you developed an alternative revenue allocation proposal for this proceeding?

A. I have. In developing my proposal for this proceeding, I considered three factors:

First, as the cost basis, I used a weighted average of the revenue requirements from the two Company ACOSSs. In this average, I weighted the results of the P&A ACOSS at 75 percent and the CD ACOSS at 25 percent, implicitly weighting the P&A ACOSS as three times more important than the CD ACOSS. I chose these weighting factors for the following reasons. In the Company's 2012 base rates proceeding, the results of my independent ACOSS (based on Commission precedent) were generally closer to those of the Company's P&A ACOSS than the CD ACOSS. For the SGS/SGDS class, an implied weighting of 75/25 of the Company's ACOSS results approximated my independent results. In addition, the P&A ACOSS is conceptually more similar to the A&E methodology that the Commission has approved for gas distribution utilities. Thus, for reasons of precedence, I weight it more heavily. My revenue allocation calculation therefore begins with an assessment of the increase needed to bring each class into line with allocated cost, based on this weighted average of ACOSS results.

Second, I considered the value of service criterion by recognizing that roughly half of the load in the Large General Service class is subject to negotiated "flex" rates, which are not assigned any of the rate increase.[22] Because retaining these customers should reduce the

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[21] Details for such an approach are shown in my workpapers, in the event that the Commission adopts a 50/50 ACOSS weighting scheme.

[22] The SGS1, SGS2 and SDS rate classes also have some loads subject to flex rates, but the impact is sufficiently small that I have not made any adjustments for these customers. In effect, the cost of the flex rate shortfalls is borne within the class

revenue requirement that gets assigned to all other classes, I did not assign any increase to those customers.[23]

Third, to reflect the principle of rate gradualism, I limited the increase to any rate class to be no more than 2.0 times the system average. While there are no "hard-and-fast" rules for gradualism, limiting the maximum increase to 1.5 to 2.0 times the system average increase is not uncommon. In my analysis, this limit is applied to the Large General (regular tariff rate) class. In addition, I adjusted the revenue requirement for the SGS2 class to avoid a rate decrease.

Fourth, I reject the Company's proposal for an increase for Rate MDS, because (a) revenues already substantially exceed allocated costs, and (b) the Company's proposed increase reflected only the C&I Network charge, which I exclude in my analysis.

Fifth, the net revenue shortfall that reflects from the adjustments in Steps 2, 3 and 4 above is reallocated to the remaining classes (Residential, SGS1, and Medium General) on the basis of overall allocated cost.

Supporting calculations are shown in Exhibit IEc-3, and in my electronic workpapers.

Q. Why do you not rely on the Traditional P&A ACOSS method in developing your revenue allocation proposal?

A. As I indicated earlier, none of the traditional cost allocation approaches for gas distribution mains costs provide a theoretically sound approach for recognizing the specific usage of individual components of the distribution system. As such, these methods simply cannot reflect such system differences as:

[23] Due to time and information constraints, I did not conduct an evaluation of Columbia's flex rate customers in this proceeding. In general, it is reasonable to allow a utility to offer negotiated, below fully allocated cost rates to customers if (a) it can be demonstrated that the customer would not take service at a full-cost rate, and (b) the revenues from the customer exceed the incremental cost of providing service to the customer. For the purposes of this testimony, I assume that these conditions apply to the Company's flex rate customers, and that it would therefore be impossible to recover any of the rate increase from these customers.

- Whether large mains have been extended to serve large commercial or industrial customers or whether the extension serves distributed residential customer networks;

- Whether gas distribution mains must be extended for longer distances to serve small and medium commercial customers than for residential customers, or whether such commercial customers are more likely to be more geographically concentrated in commercial areas, thereby requiring less main extension;

- Whether the very significant economies of scale associated with the use of larger and higher pressure mains are proportionally related to all customer class loads, or whether the economic benefits disproportionately result from serving particular customers or classes.

These problems cannot be solved without a detailed assessment of system configuration and mains usage. While Columbia has not undertaken such an analysis in this proceeding, the segregation of mains into categories is a step in the right direction. By segregating mains by size/pressure, the Company's method provides some recognition of the scale economies of serving fewer larger customers than serving many small customers.

Moreover, Columbia has made reasonable efforts to try to ensure that this segregation of mains costs is as accurate as possible, by (a) assigning no costs for small mains costs to any customer served from the larger, higher-pressure mains, and (b) assigning costs for larger, higher-pressure mains that serve only larger customers only to those customer classes.

Finally, it must be recognized that the Traditional P&A method produces allocated cost results for the Large General Service class that are significantly at variance with current rates, and which will very likely result in a further shift to negotiated flex rates for that class. As it is, the average distribution rates for non-flex Large General Service customers are more than 3.5 times higher than those for flex rate customers (on a per-Dth basis), and my algorithm already maxes out the rate increase for those customers. The Traditional P&A approach would imply a substantially larger revenue shortfall from that class, which simply cannot be recovered given the settlement pattern of the last decade of base rate increases. Thus, while a Traditional P&A method could, as an arithmetic exercise, be adopted for cost allocation purposes, it is unlikely that it would have any useful implications for rate setting for the Large General Service class, and would increase the magnitude of the revenue shortfall that must be reallocated to the other rate classes. A cost allocation result that is that far at variance with market conditions at least suggests that there is a technical problem with the methodology.

Q. **What are the implications of your revenue allocation proposal?**

A. Table IEc-7 below shows the results of my proposed revenue allocation, compared to the Company's proposal. As shown, despite using a very different approach than that adopted by the Company, my calculations produce only relatively modest differences in revenue allocation, particularly if the SGS1 and SGS2 classes are viewed in aggregate. Thus, while the Company indicates that it relied equally on its two ACOSS methods, its actual revenue allocation suggests that it relied more heavily on its P&A ACOSS.

Table IEc-7 RDK Proposed Revenue Allocation ($000)								
	Total	Resi-dential	SGS1	SGS2	Medium General	Lg Gen Regular	Lg Gen Flex	MDS
Current Revenues	410,250	303,756	35,051	34,599	17,741	13,878	4,021	1,204
Increase to CBR (1)	46,835	29,996	2,797	-2,375	2,823	4,373	10,283	-1,061
Adjustments (2)	-8,051	—	—	2,375	0	-1,204	-10,283	1,061
Reallocate (3)	8,051	6,852	777	—	422	0	0	0
RDK Revenue Allocation	46,835	36,848	3,574	0	3,245	3,169	0	0
Percent Increase	11.4%	12.1%	10.2%	0.0%	18.3%	22.8%	0.0%	0.0%
Compare: Company Proposal	46,835	37,630	2,381	2,157	2,500	2,125	0	42

Notes:

(1) Increase necessary to bring rates into line with allocated costs, based on 75/25 weighting of Company P&A and CD ACOSSs.

(2) Adjustments to eliminate reductions (MDS, SGS2), eliminate increases to flex rate customers (Large General Flex) and to limit increase to 2.0 times system average (SGS1).

(3) Net adjustment shortfall reallocated to Residential, SGS2, Medium General, and Large General (regular) in proportion to fully allocated cost.

6. <u>Rate Design Issues</u>

Q. Please describe the tariff structure for the SGSS, SCD and SGDS rate classes.

A. Base rate tariff charges for these three classes currently consist of a bifurcated monthly customer charge and a bifurcated commodity charge, both split between customers with annual consumption above and below 644 Dth. Within each size category, SGSS and SCD customers pay the same commodity charge, while SGDS customers pay a slightly lower commodity charge reflecting the fact that the Company does not incur gas storage working capital costs for regular transportation customers.. The basic distribution rate tariff structure is shown in Table IEc-8 below.

In addition, the SGSS sales customers are subject to PGC, GPC, MFC and Rider CC charges. Rate SCD Choice and Rate SGDS transportation customers are subject to certain PGC charges (related to load balancing), and the Rider CC charge.

Q. How does Columbia propose to implement its rate increase for these classes?

A. Columbia's proposed increases for the base rates components of Small General Service classes are shown in Table IEc-8 below.

Table IEc-8
Columbia Proposed Small General Service Base Rate Design

	Current Rate	Proposed Rate	Percent Increase
Rates SGSS and SCD			
Customer Charge < 644Dth/year	$21.25	$22.75	7.1%
>644 Dth/year	$48.00	$48.00	0.0%
Commodity Charge <644 Dth/year	$4.0870	$4.3643	6.8%
>644 Dth/year	$3.6288	$3.8082	4.9%
Rate SGDS			
Customer Charge < 644Dth/year	$21.25	$22.75	7.1%
>644 Dth/year	$48.00	$48.00	0.0%
Commodity Charge <644 Dth/year	$3.9056	$4.2423	7.4%
>644 Dth/year	$3.6288	$3.8082	4.9%

Q. What approach do you recommend for setting rates for these classes?

A. In general, for small and medium general service classes, I advocate setting the customer charge at or near the customer-related costs for the smaller customers within each class. The commodity charge is then adjusted to produce the appropriate revenue requirement.

Q. How do you determine the cost basis for the customer charge?

A. I begin with a weighted average of the two ACOSS methods (as corrected), and determine the per-customer costs that are allocated using customer-based allocation factors. In developing the cost basis for the customer charge, I take a relatively simple approach to the problem, in that I include all costs that are allocated on a customer basis. I recognize that some experts, and at least some Commission precedent, support the exclusion of certain "indirect" customer-related costs from this calculation. Nevertheless, I follow the basic principle that the rates should follow the costs. If customer charges are set below the allocated customer cost, then larger customers will subsidize smaller customers, as measured by the logic of the ACOSS. While subsidizing smaller customers may have a public policy rationale for the residential class, I see no particular advantage to such an intra-class cross-subsidy for the non-residential classes.

However, in making the calculations, I *excluded* all uncollectibles costs from customer-related costs. Uncollectibles costs are essentially a fee on customers who pay their bills to compensate the utility for those customers who do not. As these costs are essentially a tax, I deem it reasonable to recover these costs with volumetric charges within the small business classes. This approach is conceptually similar to the Company's treatment of universal service costs within the Residential class.

Q. What are the implications of your analysis for the SGS/SGDS customer class customer charges?

A. My analysis indicates that the fully loaded customer cost based on my 75/25 weighted average ACOSS approach is $34.06 for the Residential class, $38.78 for the Small General Service class (under 644 Dth/year) and $61.23 for the Small General Service class (over 644 Dth/year). In light of this analysis, I believe that the Company's proposals to modestly increase the SGS1 customer charge to $22.75 and to hold the SGS2 customer charge at $48 are both reasonable, at the full revenue requirement. If the Company's overall increase is scaled back, the increase in the customer charge for SGS1 should similarly be scaled back.

7. Revenue Decoupling

Q. Please summarize the Company's proposal for revenue decoupling in this proceeding.

A. The Company currently has a weather normalization adjustment ("WNA") pilot program for the Residential class. It proposes to supplement that program with a revenue normalization adjustment ("RNA") program, also limited to the Residential class. The RNA would be a per-customer revenue decoupling program, in which the Company would be allowed to reconcile any variances between approved and actual base distribution revenues per customer. (Customers would exclude those participating in the Customer Assistance Program ("CAP").) The approved values would be calculated for each of two six-month periods (April-September, and October-March). Per-customer variances would be calculated for each period, and multiplied by actual customer count to get the dollar variance. The variance would then be recovered in the corresponding period (i.e., October-March variances would apply to the October-March period in the next year), through the RNA charge based on the dollar value of the variance per unit of forecast load. Interest on over- and under-recoveries at the prime commercial lending rate would apply.

Q. What are the generic advantages of a revenue decoupling mechanism?

A. Rate decoupling mechanisms, including partial decoupling approaches such as weather normalization, reduce the utility's exposure to volume fluctuations. As I discussed earlier, over the longer term, a gas distribution utility's costs vary with customer count and peak demands, the latter typically being significantly correlated with energy consumption. However, in the short run, the utility's investment in the distribution system is substantially fixed, while its rate revenues are significantly dependent on energy consumption. Thus, year-to-year fluctuations in customer loads result in fluctuations in utility margin and profitability, causing financial risk for the utility. A full revenue decoupling mechanism eliminates risks associated with volume fluctuations. In theory at least, this risk reduction should manifest itself in a lower cost of capital for the utility, which can (and should) be passed on to ratepayers.

A secondary benefit to revenue decoupling mechanisms is that the volumetric component of rates, which reflects the longer-term variability of distribution system costs, can be retained in the basic tariff structure without imposing risk on the utility. This allows rates to better match longer term costs, and provides reasonable price signals for economically efficient energy conservation. Without revenue decoupling mechanisms, gas distribution utilities can have an incentive to discourage energy conservation.

Finally, a rate decoupling mechanism has a modest regulatory benefit, particularly in a fully-forecast future test year environment, in that the need to precisely forecast customer loads to derive rates is substantially reduced. Since rates in a decoupled environment will essentially be based on actual loads, forecasting errors are much less harmful to both utility and ratepayers..

Q. Do the risk reduction benefits for the utility result in a corresponding increase in risk for ratepayers?

A. It depends on the nature of the load variances. Weather normalization mechanisms can be seen as "win-win." The utility's exposure to weather variances is obviously reduced. However, weather mechanisms serve to lower per-unit rates during unusually cold months and increase per-unit rates during warmer than normal months. This has the effect of partially stabilizing ratepayers' utility distribution bills. (Ratepayers, of course, remain fully exposed to bill variances related to gas supply costs.)

However, for other types of variances, a full rate decoupling mechanism does indeed shift the risk from utility to ratepayer. For example, variances due to economic fluctuations are necessarily shifted from utility to ratepayer. Similarly, revenue fluctuations due to energy conservation variances are also shifted to the ratepayer.

In addition, while a rate decoupling mechanism may eliminate the utility incentive to discourage conservation, it can create a disincentive for a utility to encourage economically efficient load growth. Because the Company's proposal is a per-customer mechanism, it will retain an economic incentive to serve new customers. However, since the Company gains no benefit from additional load, it will have no incentive to encourage additional load at existing customers, such as through electric to gas fuel switching efforts.

Q. Are broader investigations into alternative ratemaking taking place in Pennsylvania?

A. Yes. I am advised by OSBA counsel that the issue of rate decoupling, performance-based ratemaking and other "innovative" rate mechanisms are currently the subject of both potential legislation (House Bill 1782) and Commission review (Docket No. M-2015-2518883).[24] While it is not clear that completion of these efforts would necessarily provide

[24] It is my understanding that the Commission issued a Proposed Policy Statement Order at this docket by order entered May 23, 2018, and it is currently open for comment.

specific guidance for Columbia, they may provide general guidance that may not be fully consistent with the Company's proposal in this case. They may also result in filing requirements for alternative rate mechanisms, which the Company may not have met. For example, the Commission could provide guidance on how the utility cost of capital should be evaluated as a result of the lower utility financial risk.

Q. In light of this review, do you have a recommendation for this proceeding?

A. I do. For the following reasons, I recommend that consideration of this mechanism be deferred pending completion of the Commission's review and resolution of the proposed legislation.

First, the WNA already absorbs a significant share of Residential class load variances, and it has the advantages that it serves to reduce risk for both utility and ratepayer. Layering on the RNA is not beneficial to both parties, and any benefit to the utility takes the form of increased risk to ratepayers.

Second, while I have not conducted an in-depth review of the Company's cost of capital in this proceeding, it is not obvious that the risk reduction benefits of this mechanism are fully reflected in the claimed costs.

Third, there is significant uncertainty about Pennsylvania policy in this respect given the outstanding legislative and Commission activities. Deferring this issue could prevent unfortunate inconsistencies, as well as potentially avoiding duplicative regulatory efforts.

Q. Does this conclude your direct testimony?

A. Yes, it does.

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

Overview

Mr. Knecht has more than 35 years of practical economic consulting experience, focusing on the energy, utility, metals and mining industries. For the past 25 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 worked for 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.

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 twenty 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 INDUSTRIAL GAS USERS ASSOCIATION, Mr. Knecht provided consulting and expert witness services in a generic cost allocation proceeding involving Gaz Métro before the Régie de l'énergie in Québec.

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.

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INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2016-2580030	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	April 2017	Pennsylvania Office of Small Business Advocate	Test year, load forecast, O&M expenses, rate base, rate of return, cost allocation, rate design, EE&C program, capacity assignment
Matter 336	New Brunswick Energy & Utilities Board	New Brunswick Power	January 2017	New Brunswick Public Intervener	Financial forecast, equity requirement, depreciation life, variance mechanisms, cost allocation, rate design
Matter 338	New Brunswick Energy & Utilities Board	Generic	December 2016	New Brunswick Public Intervener	Retail petroleum margins
Matter 330	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2016	New Brunswick Public Intervener	Revenue requirement, investment test, customer retention initiatives, cost allocation, rate design
R-2016-2537359	Pennsylvania Public Utility Commission	West Penn Power Company	July 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
R-2016-2537355	Pennsylvania Public Utility Commission	Pennsylvania Power Company	July 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
P-2016-2537609, 2537594	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas	July 2016	Pennsylvania Office of Small Business Advocate	Waiver of DSIC cap.
P-2016-2543523	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Electric Division	July 2016	Pennsylvania Office of Small Business Advocate	Default service procurement.
R-2016-2529660	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	June 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
R-2015-2469275	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	May 2016	Pennsylvania Office of Small Business Advocate	Default service procurement plan.
R-2015-2518438	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Gas Division	April 2016	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design, energy efficiency and conservation program.

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INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
P-2016-2521993	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	April 2016	Pennsylvania Office of Small Business Advocate	Waiver of DSIC cap.
M-2015-2477174	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Electric Division	February 2016	Pennsylvania Office of Small Business Advocate	Energy efficiency and conservation plan review and development.
Matter No. 306	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	February 2016	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2015-2511333, 2511351; 2511355, 2511356	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, West Penn Power	January 2016	Pennsylvania Office of Small Business Advocate	Default service procurement plans, purchase of receivables.
P-2015-2501500	Pennsylvania Public Utility Commission	Philadelphia Gas Works	October 2015	Pennsylvania Office of Small Business Advocate	DSIC rate design under cash flow regulation, capital structure
P-2014-2459362	Pennsylvania Public Utility Commission	Philadelphia Gas Works	June 2015	Pennsylvania Office of Small Business Advocate	Demand side management programs, rate decoupling mechanism, incentive mechanism, cost-benefit analysis.
R-2015-2469275	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2015	Pennsylvania Office of Small Business Advocate	Misc. revenue requirement issues, cost allocation, rate design
R-2015-2468056	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2015	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design, customer contribution policy
R-2015-2461373	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	April 2015	Pennsylvania Office of Small Business Advocate	Load balancing rates, reconciliation
R-2014-2456648	Pennsylvania Public Utility Commission	Peoples TWP LLP	March 2015	Pennsylvania Office of Small Business Advocate	Load balancing rates, reconciliation
R-3867-2013	Régie de l'énergie, Québec	Société en commandite Gaz Métro	February 2015	l'Association des Consommateurs de Gaz	Distribution cost allocation

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-3888-2014	Régie de l'énergie, Québec	Hydro Québec TransÉnergie	December 2014	AQCIE/CIFQ	Transmission customer contribution policy
R-2014-2428744 R-2014-2428742	Pennsylvania Public Utility Commission	Pennsylvania Power Company, West Penn Power Company	November 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
M-2014-2430781	Pennsylvania Public Utility Commission	PPL Electric Utilities	October 2014	Pennsylvania Office of Small Business Advocate	Smart meter procurement, rate design
Matter No. 253	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2014-2417907	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, class eligibility, reconciliation
R-2014-2406274	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2407345	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2014	Pennsylvania Office of Small Business Advocate	Customer contribution policy, alternative financing mechanism
R-2014-2408268	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2014	Pennsylvania Office of Small Business Advocate	Gas procurement sharing mechanism, cost allocation
R-2014-2397237	Pennsylvania Public Utility Commission	Pike County Light & Power (Electric)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2014-2397353	Pennsylvania Public Utility Commission	Pike County Light & Power (Gas)	April 2014	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation
R-2014-2399598	Pennsylvania Public Utility Commission	Peoples TW Phillips	March 2014	Pennsylvania Office of Small Business Advocate	Gas procurement, design day demand, cost allocation rate design, retainage
P-2013-2389572 (Remand)	Pennsylvania Public Utility Commission	PPL Electric Utilities	February 2014	Pennsylvania Office of Small Business Advocate	Time of use rates, net metering rates

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter 225	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	January 2014	New Brunswick Public Intervenor	Financial review, investment prudence, revenue requirement, cost allocation, rate design, market-based pricing.
P-2013-2391368, P-2013-2391372, P-2013-2391375, P-2013-2391378	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Pennsylvania Power, West Penn Power	January 2014	Pennsylvania Office of Small Business Advocate	Default service procurement, cost allocation, rate design
Matter No. 214	New Brunswick Energy & Utilities Board	Generic	November 2013	New Brunswick Public Intervenor	Maximum retail margins for motor fuel and residential heating oil.
Matter No. 171	New Brunswick Energy & Utilities Board	New Brunswick Power	September 2013	New Brunswick Public Intervenor	Amortization method for deferral costs associated with refurbishing Point Lepreau Generating Station
C-2013-2367475	Pennsylvania Public Utility Commission	PPL Electric Utilities	August 2013	Pennsylvania Office of Small Business Advocate	Forecasting and reconciliation of default service electric costs and revenues.
P-2011-2277868, I-2012-2320323	Pennsylvania Public Utility Commission	Generic	August 2013	Pennsylvania Office of Small Business Advocate	Ratemaking treatment for customers in overlapping NGDC service territories ("gas-on-gas").
P-2013-2356232	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Program design, cost recovery and rate design for alternative system expansion financing pilot program ("GET Gas")
R-2013-2355886	Pennsylvania Public Utility Commission	Peoples TWP LLC	July 2013	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2013-2361764, R-2013-2361763, R-2013-2361771	Pennsylvania Public Utility Commission	UGI Central Penn Gas, UGI Penn Natural Gas, UGI Utilities (Gas Division)	July 2013	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2012-2017

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter No. 178	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	July 2012	NB Public Intervenor	System expansion economic test, test year revenue requirement, cost allocation, rate design, treatment of stranded costs.
R-2012-2290597	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2012	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design
R-2012-2293303	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2012	Pennsylvania Office of Small Business Advocate	Treatment of pipeline credits
AUC ID #1633	Alberta Utilities Commission	Alberta Electric System Operator	April 2012	Powerex, Northpoint Energy Solutions, Cargill	Economic efficiency issues for allocation of constrained transmission capacity.
R-2012-2286447	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, reconciliation
R-2012-2281465	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2012	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas retainage, gas price procurement and hedging
R-2011-2273539	Pennsylvania Public Utility Commission	Peoples TWP	March 2012	Pennsylvania Office of Small Business Advocate	Design day demand methodology
P-2011-2273650 P-2011-2273668 P-2011-2273669 P-2011-2273670	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power	February 2012	Pennsylvania Office of Small Business Advocate	Default service procurement, retail market enhancement, rate design.
R-2011-2264771	Pennsylvania Public Utility Commission	PPL Electric Utilities	January 2012	Pennsylvania Office of Small Business Advocate	TOU Rates

Note: Dates shown reflect submission date for direct testimony.

EXHIBIT IIEc-2

SUMMARIES OF

RDK ACOSS SIMULATIONS

Columbia Gas of Pennsylvania

RDK Version of Columbia Peak & Average COSS: FY Ending December 31, 2018

$000

Summary of COSS	Total	RS/RDS	SGS1	SGS2	SDS/LGSS	LDS/LGSS	MDS/NSS
Present Rates Summary							
Sales Customer Revenues	442,811.825	337,[illegible]	46,057.1	[illegible]	5,272.9		[illegible]
Transport Customer Revenues	131,443.567	66,540.2	10,134.3	19,[illegible]	13,885.8	17,[illegible]	1,188.45
Miscellaneous Revenues	1,380.724	1,232.8	148.2	120.2	46.8	40.0	2.21
Total Revenue	575,[illegible]	425,172.6	[illegible]	53,[illegible].2	20,[illegible].0	17,[illegible].2	1,478.28
Net Purchased Gas Cost	(163,[illegible])	(120,184.1)	(21,240.4)	(18,646.7)	(3,187.7)		(269.02)
Net Revenue	411,841.178	304,[illegible]	35,169.1	34,718.5	17,787.3	17,[illegible].2	1,207.26
Other Purchased Gas Costs	1,030.078	757.1	138.8	117.5	20.0		1.69
Storage and Transportation	130.583	98.7	17.4	14.1	2.2		0.20
Distribution O&M	59,[illegible].127	44,057.8	[illegible]	4,758.9	1,049.8	[illegible]	6.06
Customer Accounts	43,849.181	42,528.5	788.2	218.8	154.0	148.5	12.40
Customer Service and Info.	1,249.307	1,136.9	93.2	15.9	1.2	0.8	0.04
Sales	879.746	803.2	66.7	9.8	0.9	0.2	0.03
A&G	61,028.074	59,008.6	7,166.1	5,310.1	3,405.4	5,928.9	9.07
Total O&M	181,617.[illegible]	148,[illegible].7	18,[illegible].4	10,[illegible].0	6,[illegible]	11,480.2	29.51
Depreciation	77,301.808	31,051.4	7,069.0	6,827.8	4,439.7	7,807.1	36.87
Other Taxes	3,456.803	2,450.7	311.2	284.4	160.1	279.8	0.50
Operating Income Before Taxes	149,065.215	122,[illegible]	13,[illegible].6	16,[illegible]	6,314.0	(1,[illegible])	1,140.39
Income Taxes	(19,811.901)	(14,387.7)	(2,125.6)	(2,942.6)	(621.8)	1,768.3	(320.89)
ITC	298.566	194.0	27.4	27.7	18.0	32.4	0.14
Net Income	129,752.881	[illegible]	11,864.2	14,083.4	5,680.3	1,111.7	820.20
Rate Base	1,815,696.487	1,228,216.0	175,530.7	180,068.7	117,580.3	210,679.1	815.73
Class Rate of Return	6.302%	7.077%	6.759%	7.826%	3.855%	0.528%	100.545%
Proposed Rates Summary							
Sales Customer Revenues	474,829.894	[illegible]	47,822.6	34,118.7	5,832.2		292.6
Transport Customer Revenues	145,762.788	74,606.5	10,949.6	21,265.8	17,776.7	20,024.7	1,221.4
Miscellaneous Revenues	1,692.444	1,310.5	158.0	128.8	49.5	42.1	3.5
Total Revenue	622,285.186	462,980.7	58,930.1	55,521.5	23,458.4	20,066.8	1,517.7
Net Purchased Gas Cost	(163,506.936)	(120,184.1)	(21,240.4)	(18,646.7)	(3,167.7)		(269.0)
Net Revenue	458,778.250	342,[illegible]	37,[illegible].7	36,[illegible]	20,290.7	20,[illegible]	1,249.7
Other Purchased Gas Costs	1,030.078	757.1	138.8	117.5	20.0		1.7
Storage and Transportation	130.583	98.7	17.4	14.1	2.2		0.2
Distribution O&M	63,411.929	44,509.7	5,646.4	4,782.7	3,079.7	5,387.8	6.6
Customer Accounts	43,849.131	42,528.5	788.2	218.8	154.0	148.5	12.4
Customer Service and Info.	1,249.307	1,136.9	93.2	15.9	1.2	0.3	0.0
Sales	879.746	803.2	66.7	9.8	0.9	0.2	0.0
A&G	61,026.074	59,006.6	7,168.1	5,310.1	3,403.4	5,926.8	9.1
Total O&M	181,576.658	148,[illegible]	13,814.8	10,594.7	6,663.3	11,464.6	30.0
Depreciation	77,301.808	31,061.4	7,038.0	6,827.9	4,499.7	7,807.1	36.9
Other Taxes	3,456.803	2,450.7	311.2	184.4	160.1	279.8	0.5
Operating Income Before Taxes	196,443.491	140,[illegible]	16,334.7	19,137.6	9,027.6	416.3	1,182.8
Income Taxes	(31,847.472)	(28,[illegible])	(2,738.7)	(3,438.2)	(1,258.5)	2,225.3	(331.1)
ITC	298.565	194.0	27.4	27.7	18.0	32.4	0.1
Net Income	165,[illegible]	114,[illegible]	13,619.4	15,672.3	7,787.1	2,673.0	851.9
Rate Base	1,815,696.487	1,228,216.0	175,530.7	180,068.7	117,580.3	210,679.1	815.5
Class Rate of Return	9.130%	9.330%	7.759%	8.581%	6.625%	1.268%	104.362%

Columbia Gas of Pennsylvania

RDK Version of Columbia Customer-Demand COSS: FY Ending December 31, 2019

$000

Summary of COSS	Total	RS/RDS	SGS1	SGS2	SDS/LGSS	LDS/LGSS	MDS/NSS
Present Rates Summary							
Sales Customer Revenues	442,318.525	357,369.8	46,087.1	33,298.4	5,272.9		288.62
Transport Customer Revenues	131,443.887	88,540.2	10,234.3	19,830.6	13,635.8	17,688.2	1,158.48
Miscellaneous Revenues	1,390.724	1,234.2	148.1	110.8	46.1	30.2	3.21
Total Revenue	575,348.115	425,174.2	56,459.5	53,238.8	20,954.8	17,588.4	1,475.28
Net Purchased Gas Cost	(163,506.936)	(120,184.1)	(21,240.4)	(18,646.7)	(3,167.7)		(268.02)
Net Revenue	411,841.179	304,990.2	35,189.1	34,718.2	17,787.1	17,588.4	1,207.26
Other Purchased Gas Costs	1,030.078	757.1	133.8	117.5	20.0		1.68
Storage and Transportation	130.383	96.7	17.4	14.1	2.2		0.20
Distribution O&M	62,858.127	50,972.3	5,442.4	3,077.4	1,848.8	1,408.2	6.08
Customer Accounts	43,849.131	42,528.3	788.2	218.6	154.0	148.5	12.40
Customer Service and Info.	1,248.807	1,136.9	93.2	18.8	1.2	0.3	0.04
Sales	879.746	803.2	65.7	9.8	0.9	0.2	0.03
A&G	81,026.074	66,628.6	6,872.4	3,658.8	2,181.6	1,665.7	9.07
Total O&M	190,017.296	162,926.1	13,313.1	7,136.2	4,318.3	3,121.8	29.31
Depreciation	77,301.808	61,466.4	6,771.5	4,298.2	2,781.1	1,947.8	36.87
Other Taxes	3,456.809	2,810.2	301.9	167.1	102.9	74.2	0.50
Operating Income Before Taxes	140,865.218	77,787.4	14,812.6	23,143.7	10,594.6	12,794.6	1,140.59
Income Taxes	(19,811.801)	(6,002.1)	(2,582.0)	(5,460.2)	(2,272.6)	(3,164.7)	(320.35)
ITC	299.369	237.2	26.2	17.2	11.1	7.6	0.14
Net Income	120,752.881	72,022.5	12,246.8	17,702.6	8,328.1	9,637.6	820.20
Rate Base	1,915,896.457	1,510,893.6	166,289.4	114,888.7	72,576.9	49,815.1	816.75
Class Rate of Return	6.302%	4.767%	7.378%	15.474%	11.482%	19.705%	100.948%
Proposed Rates Summary							
Sales Customer Revenues	474,829.864	386,963.6	47,821.8	34,116.7	5,632.2		291.8
Transport Customer Revenues	145,762.758	74,608.5	10,848.6	21,283.9	17,776.7	20,024.7	1,221.4
Miscellaneous Revenues	1,692.444	1,310.5	156.0	129.9	49.5	42.1	3.5
Total Revenue	622,285.156	462,882.7	58,830.1	55,531.5	23,458.4	20,066.8	1,517.7
Net Purchased Gas Cost	(163,506.936)	(120,184.1)	(21,240.4)	(18,646.7)	(3,167.7)		(268.0)
Net Revenue	458,778.220	342,698.6	37,589.7	36,884.8	20,290.7	20,066.8	1,249.7
Other Purchased Gas Costs	1,030.078	757.1	133.8	117.5	20.0	-	1.7
Storage and Transportation	130.383	96.7	17.4	14.1	2.2		0.2
Distribution O&M	63,411.929	51,421.2	5,470.8	3,103.2	1,878.6	1,481.8	4.6
Customer Accounts	43,846.131	42,528.3	788.2	216.8	154.0	148.5	12.4
Customer Service and Info.	1,246.807	1,136.9	95.2	19.9	1.2	0.3	0.0
Sales	879.749	803.2	65.7	9.8	0.9	0.2	0.0
A&G	81,026.074	66,628.6	6,872.4	3,658.8	2,181.6	1,665.7	9.1
Total O&M	191,576.083	163,573.8	13,441.5	7,124.0	4,648.5	3,147.1	30.0
Depreciation	77,301.808	61,466.4	6,771.5	4,298.2	2,781.1	1,947.8	36.9
Other Taxes	3,456.808	2,810.1	301.9	167.1	102.9	74.1	0.5
Operating Income Before Taxes	186,448.481	115,044.8	16,974.7	25,296.5	13,058.4	14,897.7	1,182.9
Income Taxes	(31,547.472)	(15,390.4)	(2,989.6)	(6,010.9)	(2,908.2)	(3,703.8)	(331.1)
ITC	299.568	237.2	26.2	17.2	11.1	7.6	0.1
Net Income	155,195.597	99,891.7	14,001.1	19,301.8	10,160.3	11,198.5	851.8
Rate Base	1,915,896.457	1,510,893.6	166,289.4	114,888.7	72,576.9	49,815.1	815.8
Class Rate of Return	8.100%	6.598%	8.321%	16.804%	13.990%	22.888%	104.462%

EXHIBIT IEc-3

RDK REVENUE ALLOCATION ANALYSIS

EXHIBIT IEc-3

Columbia Gas of Pennsylvania Base Rates Case

Revenue Allocation Calculations: 25/75 CD/P&A Weighting

	Total	Residential	SGS1	SGS2	SDS/LGSS	LDS/LGSS	MDS	LDS Regular	LDS Flex
Throughput	82,119,330	34,437,601	6,456,921	8,835,480	7,001,685	20,651,944	4,735,700	10,103,291	10,548,653
Current Rate Revenues Excl. COG	410,250	303,756	35,051	34,599	17,741	17,899	1,204	13,878	4,021
CD Net Revenue Requirement	457,086	373,368	36,830	22,602	14,255	9,887	143	5,543	4,344
CD Increase to CBR	46,835	69,612	1,779	-11,997	-3,486	-8,012	-1,061	-8,335	323
P&A Revenue Requirement	457,086	320,547	38,187	35,432	22,667	40,110	143	22,487	17,623
P&A Increase to CBR	46,835	16,791	3,136	833	4,926	22,211	-1,061	8,609	13,602
Wtd Avg Incr to CBR (25/75)	46,835	29,996	2,797	-2,375	2,823	14,655	-1,061	4,373	10,283
Percent	11.4%	9.9%	8.0%	-6.9%	15.9%	81.9%	-88.1%	31.5%	255.7%
Adjustments	-8,051	0	0	2,375	0	-11,486	1,061	-1,204	-10,283
Adjustment Allocator	392,163	333,752	37,848	0	20,564	0	0	0	0
Reallocate Adjustments	8,051	6,852	777	0	422	0	0	0	0
RDK Revenue Allocation	46,835	36,848	3,574	0	3,245	3,169	0	3,169	0
Percent	11.4%	12.1%	10.2%	0.0%	18.3%	17.7%	0.0%	22.8%	0.0%
Fully Allocated Cost Wtd	457,086	333,752	37,848	32,225	20,564	32,554	143	18,251	14,303

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2018-2647577**
	:	**Docket No. C-2018-3000773**
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

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

The Honorable Jeffrey A. Watson
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place, Suite 220
301 5th Avenue
Pittsburgh, PA 15222
jeffwatson@pa.gov

Lauren Burge, Esquire
Hayley Dunn, Esquire
Darryl Lawrence, Esquire
Office of Consumer Advocate
555 Walnut Street, 5th Floor
Harrisburg, PA 17101
LBurge@paoca.org
HDunn@paoca.org
DLawrence@paoca.org
(Counsel for OCA)
(Email and Hand Delivery)

Dante Mugrace
Marion Griffing
PCMG and Associates, LLC
22 Brookes Avenue
Gaithersburg, MD 20877
dmugrace@pcmgregcon.com
mgriffing@pcmgregcon.com
(Expert Witness for OCA)

Jerome D. Mierzwa
Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044
jmierzwa@exeterassociates.com
(Expert Witness for OCA)

Roger D. Colton
Fisher, Sheehan and Colton
34 Warwick Road
Belmont, MA 02478
roger@fscconline.com
(Expert Witness for OCA)

Erika L. McLain, Esquire
Bureau of Investigation & Enforcement
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
ermclain@pa.gov
(Counsel for BIE)
(Email and Hand Delivery)

Theodore J. Gallagher, Esquire
Meagan Bielanin Moore, Esquire
Columbia Gas of Pennsylvania, Inc.
121 Champion Way, Suite 100
Canonsburg, PA 15317
tjgallagher@nisource.com
mbmoore@nisource.com
(Counsel for Columbia Gas)

Michael W. Hassell, Esquire
Lindsay A. Berkstresser, Esquire
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101
mhassell@postschell.com
lberkstresser@postschell.com
(Counsel for Columbia Gas)

Todd S. Stewart, Esquire
Hawke McKeon & Sniscak LLP
100 North Tenth Street
Harrisburg, PA 17101
tsstewart@hmslegal.com
(Counsel for NGS Parties)

Joseph L. Vullo, Esquire
Burke Vullo Reilly Roberts
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com
(Counsel for Community Action Assoc. of PA)

Thomas J. Sniscak, Esquire
William E. Lehman, Esquire
Whitney E. Snyder, Esquire
Hawke McKeon & Sniscak, LLP
100 North Tenth Street
Harrisburg, PA 17101
tjsniscak@hmslegal.com
welehman@hmslegal.com
wesnyder@hmslegal.com
(Counsel for Pennsylvania State University)

James L. Crist
Lumen Group, Inc.
4226 Yarmouth Drive, Suite 101
Allison Park, PA 15101
JLCrist@aol.com
(Expert Witness for PSU)

Charis Mincavage, Esquire
Alessandra L. Hylander, Esquire
McNees Wallace & Nurick LLC
100 Pine Street, PO Box 1166
Harrisburg, PA 17108
cmincavage@mcneeslaw.com
ahylander@mcneeslaw.com
(Counsel for CII)

Patrick M. Cicero, Esquire
Kadeem G. Morris, Esquire
Elizabeth R. Marx, Esquire
Pennsylvania Utility Law Project
118 Locust Street
Harrisburg, PA 17101
pulp@palegalaid.net
(Counsel for CAUSE-PA)

Dan Clearfield, Esquire
Kristine Marsilio, Esquire
Eckert Seamans Cherin & Mellott, LLC
213 Market Street, 8th Floor
Harrisburg, PA 17101
dclearfield@eckertseamans.com
kmarsilio@eckertseamans.com
(Counsel for Direct Energy)

DATE: June 7, 2018

Daniel G. Asmus
Assistant Small Business Advocate
Attorney I.D. No. 83789

COMMONWEALTH OF PENNSYLVANIA

July 3, 2018

The Honorable Jeffrey A. Watson
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place, Suite 220
301 5th Avenue
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. / Docket No. R-2018-2647577

Dear Judge Watson:

Enclosed please find the Rebuttal Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1-R, with Exhibits IEc-R1 and IEc-R2, on behalf of the Office of Small Business Advocate, 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,

Daniel G. Asmus
Assistant Small Business Advocate
Attorney ID No. 83789

Enclosures
cc: 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-2018-2647577**
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Rebuttal Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
OFO/OMO Issues

Date Served: July 3, 2018

Date Submitted for the Record: July 26, 2018

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. **Witness Identification and Introduction**

Q. Mr. Knecht, 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. Please identify the issues addressed in this rebuttal testimony.

A. This rebuttal testimony responds to the direct testimony submitted by the Commission's Bureau of Investigation and Enforcement ("I&E") witness Ethan H. Cline and Pennsylvania Office of Consumer Advocate ("OCA") witness Jerome B. Mierzwa with respect to cost allocation and revenue allocation issues. I also respond to the direct testimony of Mr. James L. Crist on behalf of Penn State University ("Penn State") regarding revenue allocation, and the direct testimony of Laura Greenholt-Tasto on behalf of the Natural Gas Supplier Parties ("NGSs") regarding OFO/OMO issues. My response to each witness is presented sequentially below in Sections 2 through 5.

2. **I&E Witness Cline (Cost Allocation, Revenue Allocation)**

Q. Please review the Company's filed cost allocation studies.

A. In this proceeding, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company") submitted three allocated cost of service studies ("ACOSSs"). The differences between these ACOSSs relate only to the classification and allocation of mains costs. More specifically, the Company submitted one ACOSS that relies on the "peak-and-average" ("P&A") methodology, one ACOSS that relies on a customer-demand minimum system ("CD") methodology, and an ACOSS based on a 50/50 simple average of the two methods. All three ACOSSs submitted by the Company segregate mains into transmission pressure, regulated pressure and low pressure categories, with transmission and regulated pressure mains costs being assigned to all customers and low pressure mains being assigned only to customers who take service at lower pressure.[1]

Q. What is Mr. Cline's recommendation regarding cost allocation?

A. Mr. Cline recommends that the Company's P&A ACOSS be used for revenue allocation and rate design in this proceeding. My reading of his testimony is that Mr. Cline relies solely on Commission precedent in making this recommendation, specifically noting:

- The Commission approved the P&A method in a case involving National Fuel Gas Distribution, 83 Pa. PUC 262 (1994) ("NFG Case");
- The Commission explicitly rejected the recognition of a customer component for mains costs (which the Company's CD method has) in matters involving the Philadelphia Gas Works (Docket No. R-00061931) ("PGW case");
- The Commission determined that the cost basis for the customer charge in a Pennsylvania American Water Company case (Docket No. R-00932670) ("PAWC case") should include only "direct customer costs" which do not include any mains costs;
- Mr. Cline is unaware of any case in which the Commission has accepted the use of a CD methodology for developing a cost of service study.

Q. Do you agree with Mr. Cline that Commission precedent on this issue is dispositive?

A. Unfortunately I cannot. I agree with Mr. Cline that in proceedings involving natural gas distribution companies ("NGDCs"), notably the NFG case, the PGW case, and the PPL Gas case cited at footnote 10 of my direct testimony, the Commission has determined that including a customer component of costs for mains classification is not appropriate. However, in the more recent cases (PGW and PPL Gas), the Commission did not approve the use of a P&A allocation factor and instead adopted the use of an "average-and-

[1] In allocating regulated pressure mains, the Company further segregates the plant into mains which are not used to supply gas to the low pressure system and those that do. Costs for the former category are assigned only to customers who take service at regulated pressure, while costs for the latter are assigned to all customers.

excess" ("A&E") allocation factor. The A&E method is conceptually quite different from the P&A methodology, it can produce very different quantitative results, and it requires judgement in the selection of weighting factors for the "average" and the "excess" components. Mr. Cline has not proposed that the A&E allocation method for mains be adopted in this proceeding, nor does he explain why he rejects the more recent Commission precedent in that respect.

Also, I respectfully disagree with Mr. Cline's view that the Commission has not approved a CD-type methodology for any utility in Pennsylvania. As I indicated in my direct testimony, the Commission has explicitly affirmed the use of a minimum system methodology for classifying electric distribution system costs (at both primary and secondary voltages). As the economic logic for classifying distribution costs is closely parallel for electric and gas distribution systems, I do not believe that it is reasonable to dismiss Commission precedent in this respect as irrelevant.

Further, I respectfully disagree that the Commission's policy with respect to including only direct customer costs in the cost basis for the customer charge in the PAWC case is relevant to cost allocation. Simply recognizing that there are both direct and indirect customer costs would tend to suggest that perhaps some component of mains costs could reasonably be considered indirect customer costs. Moreover, rate design policy will often consider many more factors than cost allocation, which tends to rely more explicitly on cost causation. Thus, establishing a rate design policy for deriving the customer charge is likely based on factors other than strict cost causation.

Finally, as Mr. Cline recognizes, the P&A method results in rate implications that simply cannot be adopted, as they would require massive rate increases for both the Medium General (SDS/LGSS) and the Large General (LDS/LGSS) service rate classes. Increases of this magnitude cannot reasonably be achieved in the foreseeable future due to negotiated flex rate concerns and the principle of rate gradualism. Table IEc-R1 below shows the average unit cost for each class based on (my version of) the Company's P&A methodology, the current average unit revenues, and the implied percentage increase.

Note that I have segregated the Large General Service class into regular and flex rate customers, using the cost assignment method specified in my direct testimony.

Table IEc-R1
Implications of Columbia P&A ACOSS Methodology
$/Dth

	P&A Unit Cost	Current Avg. Unit Revenue	Increase Required
Residential	$9.27	$8.82	5.1%
SGS1	$5.89	$5.43	8.5%
SGS2	$4.04	$3.92	3.1%
SDS/LGSS	$3.40	$2.53	34.3%
LDS/LGSS Reg.	$2.23	$1.37	62.4%
LDS/LGSS Flex	$1.67	$0.38	339.4%
MDS	$0.04	$0.25	-85.5%
Total	$5.57	$5.00	11.4%

Sources: RDK WP1

Table IEc-R1 highlights a number of problems with sole reliance on the P&A ACOSS methodology. First, the method produces allocated cost results that are more than four times higher than current rates for the flex-rate LDS customers, which represents roughly half the class volume. Unless the Commission should determine that the Company has improperly assigned discounted rates to those customers (see below), there is no way to recover the cost shortfall from these customers. A cost allocation methodology that produces results so far afield from rates that can be economically justified in competitive conditions should be suspect.

In addition, the costs assigned to the Medium General and even the regular rate Large General customers are far in excess of current rates. As Columbia has had seven previous base rates cases in the past ten years, it is apparent that the settling parties at least implicitly considered factors other than the P&A ACOSS in deriving the rate requirements for those classes.

Q. What is Mr. Cline's position with respect to revenues earned from flex rate customers?

A. Mr. Cline reviewed the confidential information regarding flex rate customers and concluded that six of these customers have not had their rates validated since 2008 and one since 2010. Mr. Cline concludes that the Company should be required to demonstrate that these customers should remain eligible for flex rates under more recent market conditions in its next base rates case.

Q. Do you agree with Mr. Cline in this respect?

A. I very much agree that the Company should be required to demonstrate that all claimed flex rates in a base rates proceeding are necessary to retain those customers, and the flex rates produce revenues in excess of the incremental cost to serve those customers. At this writing, I am not currently entitled to review the confidential information supporting Mr. Cline's analysis. However, based on Mr. Cline's representations, it is not clear to me that the Company has, in fact, reasonably demonstrated that all the flex rate discounts claimed in this proceeding are just and reasonable. It is also unclear why Mr. Cline accepts these flex rates as reasonable for this proceeding. I am advised by counsel that OSBA serves notice to the Company that it may choose to address this issue through cross-examination and briefing in this proceeding.

Q. What is Mr. Cline's proposed revenue allocation in this proceeding?

A. Mr. Cline argues generally that revenue allocation should serve to move class rates of return closer to system average. However, he exempts the Medium General (SDS/LGSS) and Large General (LDS/LGSS) classes from that requirement because some of those customers have flexed rates and cannot be assigned increases. He therefore concludes that the target return for the smaller customer classes must be set above system average, to accommodate the shortfall from the flex rate classes. Mr. Cline's proposal is shown in Table IEc-R2 below.[2]

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[2] Evaluating Mr. Cline's proposed revenue allocation is somewhat complicated by an apparent inconsistency between I&E Exhibit No. 3, Schedules 13, 14 and 15. In general, I have relied on the revenue allocation implied by Schedules 13 and 15 rather than the values shown in Schedule 14, as the values in Schedules 13 and 15 appear to be more consistent with the rationale presented in the text of Mr. Cline's testimony.

Table IEc-R2 Summary of I&E Revenue Allocation Proposal ($000)				
	P&A Cost-Based Increase	Percent Increase	I&E Revenue Allocation	Percent Increase
Residential	15,403	5.1%	32,912	10.8%
SGS1	2,977	8.5%	5,504	15.7%
SGS2	1,085	3.1%	3,846	11.1%
SDS/LGSS	6,087	34.3%	2,504	14.1%
LDS/LGSS Reg.	8,666	62.4%	2,129	15.3%
LDS/LGSS Flex	13,647	339.4%	0	0.0%
MDS	(1,029)	-85.5%	42	3.5%
Total	46,835	11.4%	46,937	11.4%
Sources: RDK WP1, Exhibit IEc-R1				

Q. If the Commission approved the P&A ACOSS methodology recommended by Mr. Cline, would you agree with his proposed revenue allocation?

A. No. Mr. Cline's proposed revenue allocation is not consistent with the cost allocation method he supports. The primary source of this problem is that Mr. Cline ignores the cost allocation results for the Medium General (SDS/LGSS) and Large General (LDS/LGSS) rate classes, ostensibly on the grounds that these classes contain flex rate customers.

However, in the case of the Medium General (SDS/LGSS) class, only 3.0 percent of throughput and 0.8 percent of current revenues are related to flex rate customers. The vast majority of customers in the class pay regular tariff rates. As such, the results of the ACOSS can reasonably be applied to the class as a whole. And, in that respect, despite the fact that the class would need a 34.3 percent increase to move rates into line with costs, Mr. Cline proposes only a 14.1 percent increase, only slightly above system average. By way of comparison, Mr. Cline would assign a 15.7 percent increase to the SGS1 class, despite the fact that his cost allocation analysis would require an increase of only 8.5 percent to achieve cost-based rates.

Similarly, for the Large General (LDS/LGSS) class, while approximately one-half the load is subject to flex rates, the rest of the class pays regular tariff rates. If the P&A ACOSS method is adopted, I estimate that a 62.4 percent increase would be needed to achieve cost based rates for the non-flex customers, and Mr. Cline proposes only a 15.3 percent increase.

For the most part, Mr. Cline's revenue allocation proposals for the smaller customer classes are directionally reasonable. Regarding the SGS2 class, however, Mr. Cline proposes a rate increase that is slightly larger than that applied to the residential class, despite the fact that the P&A ACOSS would imply a materially lower increase. (In the Company's P&A ACOSS, the indexed rate of return metric for the SGS2 class at present rates is 1.20, exceeding the 1.14 value reported for the Residential class.) It is not clear why Mr. Cline does not reflect the relative results of his ACOSS for the SGS2 class by assigning a lower percentage increase than that applied to the Residential class.

Overall, my major disagreement with Mr. Cline's approach is that he chooses a cost allocation methodology which assigns significant costs to the larger-customer rate classes, but then he ignores the results of the cost allocation study in assigning the rate increase to the large customer classes. There is only limited value in a cost allocation analysis which is irrelevant to more than one-third of the overall system load.

Q. Can you address Mr. Cline's proposal for a scaleback in the event that the Commission reduces the Company's proposed rate increase?

A. In many cases, the Commission and the parties to Pennsylvania base rates proceedings adopt a "proportional scaleback" approach to this issue. If, for example, the Commission approves a $25 million increase rather than a $45 million increase, it will generally approve a revenue allocation method at the full revenue requirement, and then scale back each class' increase by a factor of 25/45 (55.6%). This is a simple and understandable approach, and it will usually produce directionally reasonable results (unless there were rate decreases at the full revenue requirement). However, it has the disadvantage that progress toward cost-based rates tends to be reduced as a result of the scaleback. Thus, I recognize Mr. Cline's effort to try to address that issue and to fashion a scaleback that retains the progress toward cost-based rates.

Mr. Cline's scaleback is shown in Table IEc-R3 below. In preparing this table, as I noted earlier, I relied on the scaleback revenue allocation implied by I&E Exhibit No. 3 Schedule 15. The scaled back increases shown in Schedule 14 would appear to imply illogical and unreasonable results.[3]

Table IEc-R3 Summary of I&E Revenue Allocation Scaleback Proposal ($000)				
	I&E Full Revenue Allocation	Percent Increase	I&E Scaleback	Percent Increase
Residential	32,912	10.8%	16,573	5.5%
SGS1	5,504	15.7%	3,156	9.0%
SGS2	3,846	11.1%	1,403	4.1%
SDS/LGSS	2,504	14.1%	1,252	7.1%
LDS/LGSS Reg.	2,129	15.3%	1,065	7.7%
LDS/LGSS Flex	0	0.0%	0	0.0%
MDS	42	3.5%	21	1.8%
Total	46,937	11.4%	23,469	5.7%
Sources: Exhibit IEc-R1				

My primary area of disagreement with this proposal again involves the treatment of the larger-customer classes. Mr. Cline's initial revenue allocation proposal for the Medium General and Large General classes was based on the logic that these were flex rate customers and therefore costs were not relevant. However, if that logic were to be accepted, there is no reason why these classes should participate in any scaleback at all. Moreover, given the vast under-recovery of costs by those classes as implied by Mr.

[3] For example, the table on page 64 of Mr. Cline's testimony appears to rely on the values in Schedule 14. Based on that table, the SGS1 class would actually be assigned a larger increase *after* the scaleback than before the scaleback, and would face a percentage increase more than three times system average. I do not believe that this was Mr. Cline's intent. See Exhibit IEc-R1 which summarizes the various parties' revenue allocation recommendations.

Cline's ACOSS methodology, the regular rate customers within these classes should certainly bear a higher burden (if Mr. Cline's P&A ACOSS method is adopted). And, again, there is no logical reason why the proposed increase for the SGS1 class should be substantially higher than that faced by the regular rate customers in the Medium General (SDS/LGSS) and Large General (LDS/LGSS) rate classes.

Within the group of the smaller customer classes, Mr. Cline's proposals are directionally reasonable. The lower increase for the SGS2 class addresses the concern that I raised above, and is more consistent with the P&A ACOSS methodology.

3. <u>OCA Witness Mierzwa (Cost Allocation and Revenue Allocation)</u>

Q. Please summarize Mr. Mierzwa's recommendation for cost allocation in this proceeding.

A. Regarding the key issue of mains classification and allocation, Mr. Mierzwa agrees with Mr. Cline that there should be no customer-component for mains costs and that mains plant should be allocated using the P&A allocator. However, Mr. Mierzwa recommends against reliance on the Company's method of segregating plant by operating pressure ("sub-functionalization") and allocating costs accordingly. Mr. Mierzwa therefore supports a method for mains allocation that I described in my direct testimony as a "Traditional P&A" approach.

Q. Let's begin with the area of disagreement between Mr. Mierzwa and Mr. Cline, namely the sub-functionalization of mains costs by operating pressure. Q. Why does Mr. Mierzwa oppose the sub-functionalization of mains costs?

A. As far as I can tell, Mr. Mierzwa's complaint is that the Company's method " . . . fails to consider the net investment of each distribution mains category." In effect, Mr. Mierzwa concludes that the Company did not reflect the fact that the low pressure/small diameter mains system is older and more depreciated than the regulated pressure/large diameter mains system, and therefore overstates costs assigned to the smaller customers who predominantly take service from the low pressure/small diameter system.

Q. Is this a reasonable complaint?

A. In my view, it is not. First, the type of "vintaging" of mains costs for cost allocation purposes that Mr. Mierzwa appears to demand is not ideal from an economic standpoint, and could lead to unstable cost allocation results. While it may seem sensible to give lower rates to customers who are served from older pipes, the economic price signals would be both more accurate and more useful if the costs being assigned represented the long-run replacement costs for the mains, rather than the historical embedded book costs.[4] Moreover, when the older, heavily depreciated mains are replaced, the customer classes that would initially benefit from vintaging could then be faced with rate shock associated with the new, high cost systems.

In addition, even if the Commission were to determine that vintaging were appropriate, Mr. Mierzwa's preferred approach also fails to adjust for the vintage problem he cites. Mr. Mierzwa's traditional P&A approach treats all mains equally, and makes no effort to assign older, more depreciated mains costs to the specific rate classes served by those mains. If vintaging is to be adopted, it becomes even more logical to move toward a direct assignment method for mains cost allocation as I recommend in my direct testimony, which would allow the Commission to know exactly which customers are served by the lower-cost, more highly depreciated mains.

Q. At pages 10-11 of his testimony, Mr. Mierzwa offers an example as to why mains costs are in no way proportional to customer count, and that increasing customers does not result in any need to extend gas mains. Is this a credible argument?

A. It would be, if Mr. Mierzwa could demonstrate that large customers are always at the end of the pipe, and that smaller customers are always located closer to transmission system gate stations, as is the case in his example. In reality, while it is certainly possible that some distribution laterals exhibit the specific topography specified in Mr. Mierzwa's example, larger non-residential customers are generally more likely to be located either nearer the gate station or in more concentrated business areas, while smaller residential customers are more spread out in the more remote areas of the distribution systems.

[4] In mains classification studies, such as the minimum system method using the Columbia's CD ACOSS or alternatively in "zero-intercept" methods, most analysts address the mains cost vintage issue by adjusting historical mains costs for construction cost inflation.

Absent some detailed assessment of the physical layout of the system and the actual location of customers, Mr. Mierzwa's example is not dispositive as to the question at hand, since more realistic examples would imply exactly the opposite conclusions. Moreover, common sense dictates that as new customers are added to the system, mains footage is likely to increase.

I would add that in his example, Mr. Mierzwa recognizes that the lateral must be sized to meet the peak demand of the industrial facility (at the end of the pipe). I agree. The size of the main is determined by peak demand, and is unrelated to whether that industrial facility operates at peak for one day per year or for 365 days per year.

Q. At page 11, Mr. Mierzwa argues that the minimum system CD method implicitly assigns a specific footage of mains to each customer, and that it is unreasonable to assume that the same footage is needed for each customer. Can you respond?

A. I generally agree with Mr. Mierzwa's mathematical interpretation, although I would phrase it a little differently. The minimum system CD method assigns a customer-related cost to each customer that is based on (a) a fixed number of feet and (b) the unit cost of minimum system pipe. The CD method also assigns demand-related costs based on the customer's overall demand. However, I am unable to replicate Mr. Mierzwa's fixed footage numbers, which appear to be overstated. (For example, the average low pressure system footage per customer is closer to 25 feet than to the 65 feet reported by Mr. Mierzwa.) Moreover, because the Company (and I) use a weighted average of the CD and the P&A methods, the implied fixed footage impacts are effectively much smaller in the ACOSS used for revenue allocation.

Mr. Mierzwa is also certainly correct that it is not logical to simply assume that the customer component of mains costs should be based on the same number of feet of minimum sized mains for each and every customer. However, it is equally illogical to assume that the cost to extend the gas distribution system to each and every customer is unrelated to customer location, that the costs exhibit zero economies of scale, and that costs are exactly proportional to a 50/50 average of customer load and customer design day demand. All simplistic cost allocation methods such as the CD and P&A methods implicitly include these types of unrealistic assumptions.

Q. Ag pages 11-12 Mr. Mierzwa also argues that non-residential customers are typically located farther apart than Residential customers and presents as evidence a sampling of recent large customer attachments. Please comment.

A. As a matter of common sense, I would generally agree with Mr. Mierzwa that it is likely that large industrial customers are located farther apart than residential customers, as are large retail stores. However, for small and medium businesses (who tend to use more gas than residential customers), this line of reasoning does not obviously apply. Small and medium businesses may very well be located in concentrated commercial areas, such that the density for those customers is actually higher than that for residential customers. Again, this issue can only be evaluated using a detailed assessment of the gas distribution system and the specific customers served downstream of each pipe segment, and not by the dueling speculations and hypothetical examples of cost allocation experts.

Q. At pages 11-12, Mr. Mierzwa cites Principles of Public Utility Rates, Bonbright et al., in support of the assertion that there is no customer component to cost. Can you respond?

A. The essence of Professor Bonbright's analysis is that there is weak correlation between distribution system distance and number of customers. Unfortunately, Professor Bonbright's statistical analysis supporting that conclusion is not available for review. Moreover, for gas distribution utilities, the most recent statistical analysis that I have seen demonstrates quite a strong correlation between mains footage and number of customers, and only a very weak correlation between mains footage and loads. As such, the analysis which I have been able to review contradicts the professor's conclusion.[5]

I would note also that the Bonbright text cited by Mr. Mierzwa relates to the electric distribution system. As I indicated earlier, the Commission has already concluded that a customer component for electric distribution is appropriate for Pennsylvania. In so

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

doing, the Commission was well aware of Professor Bonbright's conclusion, and, at least implicitly, rejected it.

Q. At page 14, Mr. Mierzwa argues that all or nearly all residential customers could be fully served with a 2-inch main minimum system. Do you agree?

A. As a technical matter, I do not. The theoretical construct which is the minimum system method assumes that all mains are replaced with 2-inch mains. In order for such a system to be able to fully meet the needs of all residential customers, Mr. Mierzwa would need to demonstrate that every residential customer downstream of each piece of pipe on the system could be served with a 2-inch main. So, for example, where the minimum system has replaced a 10-inch steel main with a 2-inch main, Mr. Mierzwa's conclusion implies that all of the residential customers downstream of that main could be fully served. As a matter of common sense, I find this implausible.

Nevertheless, Mr. Mierzwa is correct that a common criticism of the minimum system method is that the customer component of costs is overstated because of the load carrying capability of the minimum system. For that reason, a "zero-intercept" method is also used in its stead, which typically produces a smaller customer component. However, in Columbia's case, this reduction in the customer component is implicitly accomplished by averaging the CD ACOSS with an ACOSS that does not include a customer component. Columbia performs the weighting on a 50/50 basis. In my direct testimony, I therefore recommended the use of a 75/25 weighting (P&A/CD), to reflect Commission precedent, for the purpose of this proceeding.

Q. At pages 21-24, Mr. Mierzwa demonstrates that there are substantial economies of scale associated with expanding mains diameter, such that the cost per unit of mains carrying capacity declines substantially as pipe diameter increases. Please comment.

A. Mr. Mierzwa is correct that there exist substantial economies of scale associated with expanding the diameter of a gas distribution main. Where I depart from Mr. Mierzwa's views is in his conclusion that these economies of scale justify the use of a commodity (average demand) allocator rather than a peak demand allocator. First, Mr. Mierzwa's recommendation defies common sense, because allocating costs based on throughput increases costs assigned to large customers. It is difficult to understand why economies of scale would support allocating *more* costs to larger customers. In fact, many experts use this same "economies of scale" argument to try to justify a larger *customer* component of cost, and therefore allocate *less* cost to larger customers. In my view, neither of these arguments is reasonable.

Any particular main segment must be sized to meet the peak demands of all firm service customers who are situated downstream from that segment. As Mr. Mierzwa demonstrates, there are significant economies of scale associated with expanding the capacity of any particular main segment, such that it is much less expensive to install a larger pipe serving multiple customers than to install smaller pipes for each customer. Some analysts argue that these economics imply that, because the standalone cost of serving a large customer is much lower, per unit of peak demand, than serving a smaller customer, the economics justify allocating a less than proportional share of the cost of that segment to the large customer, and a more than proportional share of the costs to small customers.

This standalone cost logic breaks down pretty quickly, however. Consider a particular main segment that serves many small residential customers and one large customer, such that the many small customers represent 75 percent of the downstream load. In this case, the economics of scale imply that the standalone cost of serving the residential customers as a group is lower, per unit of *class* peak demand, than the standalone cost of serving the single large customer. Thus, the "standalone" cost logic might be used to justify allocating more costs to larger customers, depending on the mix of load served downstream from a particular segment of main.

In contrast to the standalone cost logic, Mr. Mierzwa makes the reverse argument. He agrees that the marginal cost of serving incremental peak demand is much lower than the average cost (i.e., there are economies of scale in capacity), but he then concludes that the only costs related to peak demand are the marginal costs of demand. He further concludes that all other costs (i.e., the excess of average costs over marginal demand costs) are not related to peak demand, and asserts that these residual fixed costs should be allocated based on annual throughput. (It is unclear why throughput would be the relevant allocator, as there is no cost causation basis for that conclusion.) The upshot of Mr. Mierzwa's allocation method then is that costs are more than proportionately assigned to larger customers.

The problem with both of these arguments is that the analysts are attempting to assign the benefits of the economies of scale for any pipe segment to a particular type of customer. This is inappropriate. For any particular segment of main, each unit of peak load served through that segment contributes equally to the economies of scale for that segment. Therefore, the correct method for assigning the costs for a particular main segment is to recognize that the specific main must be sized to meet peak demand, and to allocate the costs, and implicitly allocate the benefits of scale economies, to each customer that is downstream of that main based on that customer's peak demand.

As I indicated earlier, mains cost allocation sometimes includes a customer component of costs. However, this customer component cannot reasonably be construed as resulting from the economies of scale for any particular segment of main. Rather, it reflects the general fact that overall mains length is proportional to number of customers. Unfortunately, as I indicated in my direct testimony, the techniques used to estimate this effect are not theoretically strong, and therefore these methods can provide only a rough approximation of the effect. For that reason, I (again) encourage the Company to evaluate whether it has the information needed to allocate mains costs on a segment by segment basis, and only to those customers served downstream from each segment. I view this approach as the only way to definitively resolve the long-standing debate regarding mains cost allocation.

Q. In addition to the P&A method, Mr. Mierzwa presents the results of a "Proportional Responsibility" ("PR") method, used by Columbia Gas in Massachusetts. Mr. Mierzwa notes that this approach produces results that are consistent with the Traditional P&A approach. Please comment.

A. The PR method is a method which allocates costs primarily based on throughput, but gives modestly heavier weights to winter month consumption relative to summer month consumption. The basic problem with the PR approach is that it does not even consider design day demand, despite near universal agreement among analysts that the distribution system must be built with sufficient capacity to meet design day demand. Moreover, the method contains no recognition that the distribution system is extended to interconnect customers. As such, the PR method is entirely divorced from cost causation. Further, the PR method is unsupported by any Commission precedent in Pennsylvania of which I am aware. As such, I recommend that it be rejected. To the extent the Commission wishes to begin considering new mains cost allocation methods, I recommend that these be focused on a more specific matching of mains with the customers served downstream.

Q. Overall, what is your assessment of Mr. Mierzwa's critique of the CD method?

A. Mr. Mierzwa raises a number of valid complaints, and some that are less valid. At least some of Mr. Mierzwa's complaints regarding the CD method apply equally to the P&A method that he favors. And while Mr. Mierzwa highlights some of the basic theoretical problems with the CD method, he does not acknowledge the similar theoretical problems with the P&A model. In particular, the P&A model fails to recognize geographical economies of scale, and it includes a volumetric factor which is unrelated to cost causation. Moreover, Mr. Mierzwa generally ignores the Company's proposal to use both the P&A and the CD methods for revenue allocation and rate design.

The basic problem is that both the CD method and the P&A method are simplistic cost allocation methods. Unless and until NGDCs develop better methods of cost allocation that reflect the specific topology of the gas distribution system (which should become increasingly possible in this era), there is little alternative but to rely on some reasonable weighting of the two methodologies, warts and all.

Q. Please summarize Mr. Mierzwa's recommendation for revenue allocation.

A. Table IEc-R4 below compares the revenue allocation necessary to move all rates exactly into line with allocated costs under the "Traditional P&A" ACOSS methodology with the revenue allocation proposed by Mr. Mierzwa. In preparing this table, I relied on my working version of the Traditional P&A methodology, which produces allocated cost results sufficiently similar to that presented by Mr. Mierzwa to be reasonably illustrative.

Table IEc-R4 Summary of OCA Revenue Allocation Proposal ($000)				
	Traditional P&A Cost-Based Increase	Percent Increase	OCA Revenue Allocation	Percent Increase
Residential	187	0.1%	29,870	9.8%
SGS1	2,144	6.1%	4,740	13.5%
SGS2	1,530	4.4%	5,304	15.3%
SDS/LGSS	6,775	38.2%	4,314	24.3%
LDS/LGSS Reg.	17,046	122.8%	2,458	17.7%
LDS/LGSS Flex	20,214	502.7%	0	0.0%
MDS	(1,061)	-88.1%	150	12.4%
Total	46,835	11.4%	46,836	11.4%
Note: The reported percentage increase for the OCA residential revenue allocation is materially lower than that reported by Mr. Mierzwa in his Table 8, primarily because Mr. Mierzwa excludes CAP customer revenues in his calculation. Sources: RDK WP6, Exhibit IEc-R1				

Q. Please comment on Mr. Mierzwa's proposal

A. Table IEc-R4 shows the extraordinarily large disparity between costs as allocated under the Traditional P&A ACOSS method and current rates. To achieve cost-based rates in the Traditional P&A method, the residential class (which represents 74 percent of current base rate revenues) need not be assigned any increase at all, while the Large General (LDS/LGSS) class would be assigned more than $37 million of the $47 million increase, resulting in a more than doubling of tariff rates for the regular customers and a sextupling of rates for the flex rate customers. Moreover, the revenue shortfall from the Medium General (SDS/LGSS) class is very substantial, likely well in excess of any increase that would be permitted under the normal constraints of rate gradualism. It is reasonably clear from this table that considerations other than the Traditional P&A ACOSS have been reflected in the historical evolution of rates over that past seven base rate proceedings in the last decade.

Nevertheless, I considered the revenue allocation implications if Mr. Mierzwa's ACOSS is adopted by the Commission. Since Mr. Mierzwa acknowledges that rate increases cannot be imposed on flex rate customers, and rate increases are typically constrained by the principle of rate gradualism, there is only limited potential in any single proceeding to address the enormous revenue shortfall from the Large General Service class, and thus the primary question is what share of this shortfall must be recovered from each of the other classes.

However, even recognizing these considerations, Mr. Mierzwa's proposal contains some inconsistencies. First, for the Large General service class, Mr. Mierzwa proposes a $2.5 million increase, or about 17.7 percent for *regular tariff rate customers*. Thus, even recognizing that rates cannot be increased for flex rate customers, Mr. Mierzwa proposes an increase only about 1.6 times system average for the regular tariff rate customers. While it might be hypothesized that Mr. Mierzwa believes that this increase is the maximum increase permitted under rate gradualism, that does not appear to be the case. Mr. Mierzwa proposes a materially larger percentage increase for the Medium General rate class (24.3 percent) than he does for the regular rate Large General customers, despite the fact that the cost performance for that class is not nearly as bad as that for the Large General class. Thus, if the Traditional P&A ACOSS is adopted, Mr. Mierzwa's proposed increase for the Large General Service class is too low.

With respect to the Medium General rate class, Mr. Mierzwa appears to propose an increase at the outer bounds of the gradualism constraint, at 2.1 times the system average. This proposal is consistent with his proposed cost allocation method, and the gradualism constraint is similar to that presented in my direct testimony (which was 2.0 times system average).

Regarding the smaller customer classes, I agree that the Traditional P&A ACOSS would justify a lower percentage increase for the Residential class than for the SGS classes. However, it is not clear why Mr. Mierzwa proposes a slightly larger increase for the

SGS2 class than for the SGS1 class, since his ACOSS shows a higher modestly higher rate of return at present rates for SGS2 (Schedule JDM-1).

Q. Overall, what is your assessment of the Mr. Mierzwa's revenue allocation proposal.

A. For the reasons discussed above, I respectfully disagree with sole reliance on the Traditional P&A ACOSS method. For that reason, I recommend against adoption of Mr. Mierzwa's revenue allocation proposal.

However, if that cost allocation method is adopted, I conclude that Mr. Mierzwa's proposed increase for the Large General Service class is understated, and that increases for the SGS1 and SGS2 classes should be adjusted to better reflect cost allocation results.

4. <u>Penn State Witness Crist (Revenue Allocation)</u>

Q. Please summarize your understanding of Mr. Crist's revenue allocation proposal.

A. Mr. Crist proposes that the Company's assignment of the rate increase to the Large General Service (LDS/LGSS) class be reduced from $1.78 million to $0.88 million, with the shortfall being assigned to non-flex customers in other rate classes. Mr. Crist does not offer a specific proposal for how the resulting shortfall would be recovered from the other classes. Mr. Crist also does not present an opinion as to the appropriate cost allocation methodology, nor does he present any revenue/cost evaluation of the non-flex rate customer subset of the Large General Service class.

Q. Please comment on Mr. Crist's proposal.

A. Since Mr. Crist does not specify a preferred cost allocation method, I assume that he relies on the Company's 50/50 weighting of CD and P&A methods. Based on my ACOSS calculations, that approach would imply a need for a substantial Large General Service class rate increase in order to achieve cost-based rates, on the order of $7.1 million or 39.7 percent. However, when I segregate costs between flex rate and regular rate customers, it becomes apparent that the class revenue shortfall is related almost entirely to the flex rate customers, and that little or no increase is necessary to move regular rates into line with allocated cost. Thus, if the Commission explicitly approves the Company's 50/50 weighting of the CD and P&A ACOSS methods, Mr. Crist's proposal for an adjustment to the Large General Service revenue allocation would be consistent with cost of service results.

However, if the Commission explicitly adopts the 50/50 ACOSS weighting approach, it would have implications for all of the other classes as well. To demonstrate this, I applied the revenue allocation algorithm shown in Table IEc-7 of my direct testimony to a 50/50 weighting of cost allocation results. (The calculations supporting this analysis were provided to the parties with my workpapers, specifically WP3.) The results are shown in Table IEc-R5 below.

Table IEc-R5
RDK Revenue Allocation Algorithm – 50/50 CD/P&A ACOSS
($000)

	Total	Resi-dential	SGS1	SGS2	Medium General	Lg Gen Regular	Lg Gen Flex	MDS
Current Revenues	410,250	303,756	35,051	34,599	17,741	13,878	4,021	1,204
Increase to CBR (1)	46,835	43,201	2,458	-5,582	720	137	6,963	-1,061
Adjustments (2)	-320	–	–	5,582	–	–	-6,963	1,061
Reallocate (3)	320	266	29	0	14	11	0	0
Revenue Allocation	**46,835**	**43,468**	**2,488**	**0**	**734**	**147**	**0**	**0**
Percent Increase	**11.4%**	**14.3%**	**7.1%**	**0.0%**	**4.1%**	**1.1%**	**0.0%**	**0.0%**
Compare: Company Proposal	46,835	37,630	2,381	2,157	2,500	2,125	0	42

Notes:

(1) Increase necessary to bring rates into line with allocated costs, based on 50/50 weighting of Company P&A and CD ACOSSs.

(2) Adjustments to eliminate reductions (MDS, SGS2) and eliminate increases to flex rate customers (Large General Flex).

(3) Net adjustment shortfall reallocated to Residential, SGS2, Medium General, and Large General (regular) in proportion to fully allocated cost.

As shown in Table IEc-R5, if the Company had actually relied on a 50/50 weighting of the CD and P&A methods, the vast majority of the rate increase should be assigned to the Residential class, with modest increases to SGS1 and Medium General, and little to no increases for the other rate classes. In effect, adoption of Mr. Crist's position would imply very substantial changes to revenue allocation for all of the rate classes. In effect, Mr. Crist's revenue allocation recommendation cannot reasonably be limited to the Large General Service class.

For the reasons laid out in my direct testimony, I do not agree with the use of a 50/50 weighting mechanism, and I instead rely on a 75/25 weighting of the P&A and CD methods respectively. In that approach, the increase necessary to achieve cost-based rates for the *non-flex* Large General Service customers would be $4.4 million or 31.5 percent, which generally exceeds the typical restrictions imposed by rate gradualism. And, of course, if the Commission adopts either the P&A or the Traditional P&A ACOSS methods supported by Messrs. Cline and Mierzwa respectively, the cost-based increase for non-flex rate Large General Service customers would be substantially higher.

Thus, if the Commission adopts any of the cost allocation recommendations of OCA, I&E or OSBA, Mr. Crist's proposal is not justified on a cost basis.

5. <u>NGS Parties Witness Ms. Greenholt-Tasto (OFO/OMO Issues)</u>

Q. Please summarize the concerns raised by Ms. Greenholt-Tasto regarding the Company's imposition of OFO/OMOs and its imbalance penalties.

A. As I understand the NGS Parties' position, they are concerned that Columbia tends to use the OFO/OMO mechanisms more frequently than do other Pennsylvania natural gas distribution companies ("NGDCs") and that the penalties for non-compliance with OFO/OMOs are excessive. Ms. Greenhold-Tasto argues that these policies are anti-competitive. She hypothesizes that the Company may deliberately be doing so in order to achieve "internal goals and management performance requirements."

She appears to propose that the maximum daily quantity requirements that currently apply to non-daily metered transportation customers be similarly applied to Columbia sales customers, although it is far from clear how such a mechanism would work.

Q. Please provide a brief background on this issue.

A. On at least a daily basis, natural gas suppliers must deliver gas to the city gate that is equal to gas customer consumption plus a provision for losses. This basic requirement applies both to the NGDCs in their role as suppliers of last report ("SOLRs") and to competitive natural gas suppliers ("NGSs"). In Columbia's case, the Company provides transportation and load balancing services for its purchased gas cost ("PGC") "sales" customers. For the retail Choice customers, NGSs are required to deliver gas at 100 percent load factor (an equal amount every day) and Columbia provides all load balancing services for those customers to reflect any and all changes in daily demand levels. For both of these sets of customers, Columbia estimates the customer gas supply requirements under extreme weather conditions, and procures the necessary upstream capacity. The costs for that capacity are reflected in PGC and Choice load balancing tariff charges.

For transportation service (Rates SGDS, SDS, LDS and MDLS), customers are generally required to supply gas equal to their daily consumption levels. However, transportation customers typically take advantage of the Company's Elective Balancing Service ("EBS"), which generally allows transportation customers to inject and withdraw gas from "banks" during non-critical periods, and which provides a 5 percent buffer range around delivery requirements during critical periods. It should be recognized that the tariff charge for the EBS service is far lower than that for the full load balancing service provided to Choice transportation customers. In Columbia's current tariff, Choice customers pay 86.9 cents per Dth for load balancing, as compared to the EBS Option 1 charges of 14.7 cents per Dth for smaller customers and 7.7 cents per Dth for larger customers.[6] These EBS charges are much lower because much of the load balancing responsibility is assumed by the transportation customers and/or their NGSs.

[6] The load balancing charge for Choice customers is the current PGDC ($1.0894/Dth) plus the PGDC E-Factor

During system critical periods, as defined by the Company, Columbia can issue an operational flow order ("OFO") or an operational management order ("OMO") which effectively requires transportation customers to deliver gas to the city gate to match some or all of their requirements. An OMO applies to transportation customers that have daily metering technology, and requires them to balance supplies to actual consumption. An OMO applies to customers that do not have daily metering, and requires them to provide supplies equal to their maximum daily quantity ("MDQ") values (or some percentage thereof). MDQ values are derived from historical maximum demands for each customer. In short, during critical periods, NGSs are required to provide the same kind of service that the NGDC provides, namely delivering gas equal to its customers' requirements, except for the limited balancing service that the transportation customers procure from the Company.

Q. Does this approach appear to be anti-competitive?

A. As a general rule, it does not. Requiring transportation suppliers to balance their supplies to their customers' loads is no different from the requirement that the NGDC must balance PGC supplies to its customers' loads, and it is therefore not anti-competitive. It simply imposes the same delivery requirements on transportation customer suppliers that are implicitly required from the NGDC itself. Unless Columbia is requiring transportation customers to supply more gas than they consume during high demand periods, there is no obvious subsidy from transportation customers to sales customers. Moreover, by allowing transportation customers the ability to inject and withdraw gas from banks during non-critical periods, and by providing them with low-cost limited balancing service during critical periods, the Company would appear to be using mechanisms designed to encourage rather than discourage competition.

While I cannot comment on whether Columbia imposes OFO/OMOs excessively, it does not appear that it does so in order to reduce capacity needed to serve PGC customers.[7]

($0.0857/Dth) less the credit for 100 percent transportation service ($0.3064).

[7] It is theoretically possible that the Company is using excess capacity retained for PGC customers during OFO/OMO periods to engage in capacity release or off-system sale transactions, which would benefit the Company through the sharing mechanism for those margins. The NGS Parties offer no evidence for any such behavior.

To supply PGC customers and to meet the balancing requirements of Choice and EBS customers, the Company develops forecasts of "design day" demand, which estimate the daily gas supply requirements under extreme weather conditions. The Company then retains sufficient upstream transportation and storage deliverability capacity to meet that demand. The costs for that capacity are reflected in the PGC charges paid by sales customers, and the load balancing charges paid by Choice customers.

Based on my recent review of the Company's design day forecasts, however, it appears that, if anything, the Company has been over-forecasting design day demands, which may cause it to retain more upstream supply capacity than absolutely necessary and in fact increase the costs of its own gas supply. Attached as Exhibit IEc-R2 is an exhibit from my testimony in the Company's most recent Section 1307(f) proceeding, showing a recent history of the design day forecasts. As shown, the longer term forecasts have consistently been scaled back. While it is not clear that this forecasting by itself has caused the Company to retain excessive capacity, the available capacity has consistently exceeded design day demands by a material amount.[8] And any retained capacity in excess of design day needs serves to increase PGC and Choice load balancing rates, making traditional transportation service look more rather than less attractive.

In addition, while the Company requires non-daily-metered customers to provide supply equal to a historically-determined MDQ, it retains capacity for sales customers based on extreme design day conditions, rather than actual historical peaks. As such, the Company would appear to be implicitly requiring less deliverability capacity from transportation customers than it must procure for its sales customers.

Finally, I note that the NGDC penalties for non-compliance with OFO/OMOs are generally not designed to reflect the Company's cost of making up any shortfall by transportation customers or their NGSs, but are in fact designed to discourage those customers from relying on the system. If there are lower cost options for making up the shortfall in deliveries, the transportation customers and their suppliers can take advantage of those opportunities and avoid the higher cost penalties.

[8] See the "Surplus Supply (Percent)" line items in Exhibit IEc-R2.

Thus, in general, the NGS Parties argument appears to be based only on the fact that Columbia may tend to require NGS Suppliers to provide the same daily load balancing for their customers that Columbia must provide to its customers more frequently than do other Pennsylvania NGDCs. I therefore see little evidence for a conclusion that the Company is engaged in anti-competitive behavior.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT IEe-R1

COMPARISON OF PARTIES'

REVENUE ALLOCATION PROPOSALS

EXHIBIT [illegible]									
Columbia Gas of Pennsylvania Base Rates Case									
Revenue Allocation Comparisons									
	Total	Residential	SGS1	SGS2	SDS/LGSS	LDS/LGSS	[illegible]	LDS Regular	LDS Flex
Throughput	32,110,330	34,437,581	6,456,921	[illegible]	7,[illegible]	20,651,944	4,735,700	10,180,201	[illegible]
Current Rate Revenues Excl. COG	410,258	[illegible]	55,051	34,559	17,741	17,[illegible]	1,204	13,878	4,021
Revenue Allocation Recommendations ($000)									
Company Proposal	46,[illegible]	37,630	2,981	2,157	2,[illegible]	2,126	42	2,126	0
RDE/OSBA Proposal	46,[illegible]	[illegible]	3,574	0	3,[illegible]	3,[illegible]	0	3,[illegible]	0
Cline/I&E Proposal (Sch 14)	46,957	33,[illegible]	5,301	3,[illegible]	2,504	2,129	42	2,129	0
Cline/I&E Proposal (Sch 15)	46,957	32,812	5,504	3,[illegible]	2,504	2,129	42	2,126	0
Mierzwa/OCA Proposal	46,[illegible]	29,[illegible]	4,740	5,[illegible]	4,[illegible]	2,[illegible]	150	2,[illegible]	0
Cline/I&E Scaleback (Sch 15)	23,[illegible]	16,570	3,156	1,[illegible]	1,252	1,065	21	1,065	0
Cline/I&E Scaleback (Sch 14)	23,[illegible]	12,[illegible]	6,156	2,[illegible]	1,252	1,065	21	1,065	0
Revenue Allocation Recommendations (% Increase in Current Base Rate Revenues)									
Company Proposal	11.4%	12.4%	6.[illegible]%	6.2%	14.1%	11.[illegible]%	3.5%	15.3%	0.0%
RDE/OSBA Proposal	11.4%	11.[illegible]%	10.2%	0.0%	[illegible]%	17.7%	0.0%	22.[illegible]%	0.0%
Cline/I&E Proposal (Sch 14)	11.4%	10.[illegible]%	[illegible]%	10.[illegible]%	14.1%	11.[illegible]%	3.5%	15.3%	0.0%
Cline/I&E Proposal (Sch 15)	11.4%	10.[illegible]%	15.7%	11.[illegible]%	14.1%	11.9%	3.5%	15.3%	0.0%
Mierzwa/OCA Proposal	11.4%	9.[illegible]%	13.5%	15.[illegible]%	24.[illegible]%	13.7%	12.4%	17.7%	0.0%
Cline/I&E Scaleback (Sch 15)	5.7%	5.5%	9.[illegible]%	4.1%	7.1%	5.[illegible]%	1.8%	7.7%	0.0%
Cline/I&E Scaleback (Sch 14)	5.7%	4.[illegible]%	17.[illegible]%	8.4%	7.1%	5.[illegible]%	1.8%	7.7%	0.0%
Revenue Allocation Recommendations (Share of Increase)									
Company Proposal	100.0%	80.[illegible]%	6.3%	4.6%	5.3%	4.5%	0.1%	4.5%	0.0%
RDE/OSBA Proposal	100.0%	70.7%	7.6%	0.0%	6.[illegible]%	6.[illegible]%	0.0%	6.[illegible]%	0.0%
Cline/I&E Proposal (Sch 14)	100.0%	70.7%	11.3%	7.[illegible]%	5.3%	4.5%	0.1%	4.5%	0.0%
Cline/I&E Proposal (Sch 15)	100.0%	70.[illegible]%	11.7%	8.2%	5.[illegible]%	4.5%	0.1%	4.5%	0.0%
Mierzwa/OCA Proposal	100.0%	63.[illegible]%	10.1%	11.[illegible]%	9.2%	5.2%	0.3%	5.2%	0.0%
Cline/I&E Scaleback (Sch 15)	100.0%	70.[illegible]%	13.4%	6.[illegible]%	5.3%	4.5%	0.1%	4.5%	0.0%
Cline/I&E Scaleback (Sch 14)	100.0%	51.4%	26.2%	12.4%	5.3%	4.5%	0.1%	4.5%	0.0%

EXHIBIT IEc-R2

SUMMARY OF COLUMBIA GAS OF PENNSYLVANIA

DESIGN DAY CAPACITY AND DEMANDS

2015/16 – 2018/19 PGC PROCEEDINGS

COPY OF EXHIBIT IEc-2
DOCKET NO. R-2018-3000253

Exhibit IEc-2

Review of Columbia Peak Day - Capacity Balances (MDth/day)

	2015-16	2016-17	2017-18	2018-19	2019-20	2020-21	2021-22
2015-2016 Filing: Exhibit HAC-2							
Storage	485.0	485.0	485.0	485.0			
City Gate FTS	175.3	175.3	175.3	175.3			
Blackhawk Storage	10.0	10.0	10.0	10.0			
Local Production	0.7	0.7	0.7	0.7			
Peak Day Supply	671.0	671.0	671.0	671.0			
Design Day Demand	642.5	[illegible]	[illegible]	[illegible]			
Surplus Supply (MDth/day)	28.5	20.1	12.4	8.3			
Surplus Supply (Percent)	4.4%	3.1%	1.8%	0.8%			
2016-2017 Filing: Exhibit HAC-2							
Storage		500.0	500.0	500.0	300.0		
City Gate FTS		175.3	175.3	175.3	175.3		
Blackhawk Storage		0.0	0.0	0.0	0.0		
Local Production		0.4	0.4	0.4	0.4		
Peak Day Supply		675.7	675.7	675.7	675.7		
Design Day Demand		[illegible]	640.3	647.1	[illegible]		
Surplus Supply (MDth/day)		42.0	35.4	28.6	22.0		
Surplus Supply (Percent)		6.6%	5.5%	4.4%	3.4%		
2017-2018 Filing: Exhibit HAC-2							
Storage			300.0	500.0	500.0	500.0	
City Gate FTS			170.3	170.3	170.3	170.3	
Blackhawk Storage			0.0	0.0	0.0	0.0	
Local Production			0.4	0.4	0.4	0.4	
Peak Day Supply			670.7	670.7	670.7	670.7	
Design Day Demand			628.2	[illegible]	[illegible]	644.6	
Surplus Supply (MDth/day)			42.5	37.2	31.7	26.1	
Surplus Supply (Percent)			6.8%	5.9%	5.0%	4.0%	
2018-2019 Filing: Exhibit HAC-2							
Storage				500.0	500.0	300.0	500.0
City Gate FTS				170.3	170.3	170.3	170.3
Blackhawk Storage				0.0	0.0	0.0	0.0
Local Production				0.7	0.7	0.7	0.7
Peak Day Supply				671.0	671.0	671.0	671.0
Design Day Demand				[illegible]	[illegible]	[illegible]	[illegible]
Surplus Supply (MDth/day)				44.1	40.2	37.2	34.6
Surplus Supply (Percent)				7.0%	6.4%	5.9%	5.4%

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2018-2647577**
	:	**Docket No. C-2018-3000773**
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

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

The Honorable Jeffrey A. Watson
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place, Suite 220
301 5th Avenue
Pittsburgh, PA 15222
jeffwatson@pa.gov

Lauren Burge, Esquire
Hayley Dunn, Esquire
Darryl Lawrence, Esquire
Office of Consumer Advocate
555 Walnut Street, 5th Floor
Harrisburg, PA 17101
LBurge@paoca.org
HDunn@paoca.org
DLawrence@paoca.org
(Counsel for OCA)
(Email and Hand Delivery)

Dante Mugrace
Marlon Griffing
PCMG and Associates, LLC
22 Brookes Avenue
Gaithersburg, MD 20877
dmugrace@pcmgregcon.com
mgriffing@pcmgregcon.com
(Expert Witness for OCA)

Jerome D. Mierzwa
Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044
jmierzwa@exeterassociates.com
(Expert Witness for OCA)

Roger D. Colton
Fisher, Sheehan and Colton
34 Warwick Road
Belmont, MA 02478
roger@fsconline.com
(Expert Witness for OCA)

Erika L. McLain, Esquire
Bureau of Investigation & Enforcement
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
ermclain@pa.gov
(Counsel for BIE)
(Email and Hand Delivery)

Theodore J. Gallagher, Esquire
Meagan Bielanin Moore, Esquire
Columbia Gas of Pennsylvania, Inc.
121 Champion Way, Suite 100
Canonsburg, PA 15317
tjgallagher@nisource.com
mbmoore@nisource.com
(Counsel for Columbia Gas)

Michael W. Hassell, Esquire
Lindsay A. Berkstresser, Esquire
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101
mhassell@postschell.com
lberkstresser@postschell.com
(Counsel for Columbia Gas)

Todd S. Stewart, Esquire
Hawke McKeon & Sniscak LLP
100 North Tenth Street
Harrisburg, PA 17101
tsstewart@hmslegal.com
(Counsel for NGS Parties)

Joseph L. Vullo, Esquire
Burke Vullo Reilly Roberts
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com
(Counsel for Community Action Assoc. of PA)

Thomas J. Sniscak, Esquire
William E. Lehman, Esquire
Whitney E. Snyder, Esquire
Hawke McKeon & Sniscak, LLP
100 North Tenth Street
Harrisburg, PA 17101
tjsniscak@hmslegal.com
welehman@hmslegal.com
wesnyder@hmslegal.com
(Counsel for Pennsylvania State University)

James L. Crist
Lumen Group, Inc.
4226 Yarmouth Drive, Suite 101
Allison Park, PA 15101
JLCrist@aol.com
(Expert Witness for PSU)

Charis Mincavage, Esquire
Alessandra L. Hylander, Esquire
McNees Wallace & Nurick LLC
100 Pine Street, PO Box 1166
Harrisburg, PA 17108
cmincavage@mcneeslaw.com
ahylander@mcneeslaw.com
(Counsel for CII)

Patrick M. Cicero, Esquire
Kadeem G. Morris, Esquire
Elizabeth R. Marx, Esquire
Pennsylvania Utility Law Project
118 Locust Street
Harrisburg, PA 17101
pulp@palegalaid.net
(Counsel for CAUSE-PA)

Dan Clearfield, Esquire
Kristine Marsilio, Esquire
Eckert Seamans Cherin & Mellott, LLC
213 Market Street, 8th Floor
Harrisburg, PA 17101
dclearfield@eckertseamans.com
kmarsilio@eckertseamans.com
(Counsel for Direct Energy)

DATE: July 3, 2018

Daniel G. Asmus
Assistant Small Business Advocate
Attorney I.D. No. 83789

COMMONWEALTH OF PENNSYLVANIA

July 17, 2018

The Honorable Jeffrey A. Watson
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place, Suite 220
301 5th Avenue
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc. / Docket No. R-2018-2647577

Dear Judge Watson:

Enclosed please find the Surrebuttal Testimony of Robert D. Knecht, labeled OSBA Statement No. 1-SR, on behalf of the Office of Small Business Advocate, 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,

Sharon E. Webb
Sharon E. Webb
Assistant Small Business Advocate
Attorney ID No. 73995

Enclosures
cc: Robert D. Knecht
Parties of Record

OSBA Statement No. 1-SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
	:	
v.	:	**Docket No. R-2018-2647577**
	:	
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	
	:	

Surrebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
C&I Network

Date Served: July 17, 2018

Date Submitted for the Record: July 26, 2018

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

Q. Mr. Knecht, 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. Please identify the issues addressed in this surrebuttal testimony.

A. This surrebuttal testimony responds to the rebuttal testimony submitted by Columbia Gas of Pennsylvania ("Columbia" or "the Company") witnesses Mr. Mark P. Balmert and Ms. Paula A. Strauss, the rebuttal testimony of Mr. Frank Plank of Knouse Foods Cooperative, Inc. ("Knouse") representing the Columbia Industrial Intervenors ("CII"), and the rebuttal testimony of Mr. Orlando Magnani on behalf of Direct Energy Business, LLC, Direct Energy Services, LLC, and Direct Energy Business Marketing, LLC (collectively, "Direct Energy").

Q. Please describe the substance of Mr. Balmert's response to your direct testimony.

A. Mr. Balmert presents a review of the various Commission precedents cited in intervenor testimony (including my own) regarding the inclusion of a customer component for classifying and allocating natural gas distribution company ("NGDC") mains costs. Mr. Balmert generally concludes that the cited Commission precedents either did not involve a case in which a customer component was advanced by a party, or involved a case in which statistical uncertainties related to the zero-intercept methodology were cited as the reason for rejecting the customer component.[1] Mr. Balmert opines that the minimum system method used by Columbia in its customer-demand ("CD") allocated cost of service study ("ACOSS") does not suffer from the statistical uncertainties inherent in the zero-intercept method, and that the Company's use of both a peak-and-average ("P&A") method and the CD method distinguish it from precedent. Mr. Balmert therefore argues that the Company's proposed method of using a 50/50 weighting of the CD method and the P&A method is not in conflict with any Commission precedent that addressed a similar proposal.

[1] I addressed the reasons why the zero-intercept method is criticized for statistical issues at page 17 in my direct testimony.

Q. Did Mr. Balmert review all of the Pennsylvania cases cited regarding the classification of NGDC mains costs?

A. No. Mr. Balmert did not address the Philadelphia Gas Works ("PGW") base rates case at Docket No. R-00061931. However, had he done so, I do not believe that his review would have affected his conclusion. In that proceeding, PGW proposed to classify mains costs into customer-related and demand-related categories based on the expert judgement of its witness, namely 25 percent customer-related and 75 percent demand-related, and further proposed that the demand-related costs be allocated entirely on a peak demand factor. In my testimony in that proceeding, I observed that PGW's classification of mains costs based on expert judgment produced a lower customer component of costs than the zero-intercept method. In the PGW matter, the Commission's Office of Trial Staff ("OTS," now I&E) proposed that the customer component be set to zero, and that mains costs be allocated using an average-and-excess ("A&E") method. The OCA also proposed that the customer component of mains costs be set to zero, and that mains costs be allocated using a peak-and-average ("P&A") methodology, albeit one weighted 20 percent peak and 80 percent average. (In this proceeding, the Company's P&A method is weighted 50/50 peak/average.) I accepted the Company's proposed method for the purpose of that proceeding.

Both the Recommended Decision from the administrative law judge and the Commission's Order in the PGW matter indicated that the Company had not demonstrated that its classification method for mains cost was reasonable, and adopted the OTS A&E method. While there is virtually no explanation provided for that decision, it is probably reasonable to conclude that the Commission had concerns about basing the cost classification for mains on expert judgment rather than on a specific quantitative methodology.

Thus, I think it's fair to conclude that, in the PGW matter, the Commission did not consider a minimum system mains classification analysis such as that presented by the Company in its CD method in this case, and it also did not consider a proposal to use an average of a CD and a P&A method.

Q. Do you have an opinion about whether Mr. Balmert's assessment of Commission precedent is reasonable?

A. No. The Commission is better able to decide what it meant in the earlier cases. In my direct testimony, I presented revenue allocation recommendations based on a 75/25 weighting of the P&A and CD methods, which I deemed to be reasonably consistent with Commission precedent. In my rebuttal testimony, I presented revenue allocation recommendations based on a 50/50 weighting of the P&A and CD methods, in the event the Commission adopts Mr. Balmert's logic.

Q. Can you summarize Ms. Strauss's rebuttal to your testimony with respect to revenue allocation?

A. Ms. Strauss's rebuttal boils down to the argument that the Company relied on its 50/50 weighted "average" ACOSS, and I relied on my own models with a 25/75 weighting. Ms. Strauss also offers the argument that the Company's principle of rate gradualism would limit class rate increases to no more than "about" 2 percentage points above and below the system average increase.

Q. Does the Company follow its own rate gradualism guidelines?

A. No. The Company's base rate increases per class (as defined in the ACOSS) range from 3.5 percent to 14.1 percent, compared to system average of 11.4 percent. Moreover, for the LDS class, if flex rate customers are ignored, the regular rate increase proposed by the Company is 15.3 percent.

Q. Is the Company's revenue allocation proposal consistent with the 50/50 weighted "average" ACOSS supported by Mr. Balmert?

A. No, it is not. First, as discussed further below, the 50/50 average ACOSS implies either a minimal rate increase or a rate decrease for the LDS regular rate customers (depending on whether my ACOSSs or the Company's ACOSS are used), and yet the Company proposes a large increase. Second, Ms. Strauss objects to my proposal to assign a zero increase to the SGS2 class. However, Mr. Balmert's 50/50 average ACOSS implies that the SGS2 class is already contributing $4.9 million in revenues than fully allocated costs at the Company's proposed rate of return.[2] And yet Ms. Strauss recommends assigning a

[2] My 50/50 average of ACOSS results produces a slightly higher value at $5.5 million, with the difference being primarily the result of my exclusion of C&I Network costs.

significant rate increase to this class, of more than 6 percent. There is no cost basis for such an increase in the Company's "average" ACOSS.

Table IEc-SR1 below shows the base rate percentage increase necessary to achieve cost-based rates, and the base rate percentage increase proposed by the Company. As Ms. Strauss appears to object to the use of my cost allocation analyses, the cost-based increases are based on Mr. Balmer's average ACOSS. In relying on Mr. Balmer's ACOSS, I segregated costs for the LDS class between flex and non-flex rate customers as described in my direct testimony, because the Company has thus far declined to do so.

Table IEc-SR1 Columbia Cost Allocation and Revenue Allocation		
Rate Class	Increase to Columbia Cost-Based Rates	Columbia Proposed Base Rate Increase
R	13.6%	12.4%
SGS1	6.8%	6.8%
SGS2	-14.3%	6.2%
SDS/LGSS	11.1%	14.1%
LDS/LGSS Non-Flex	-8.9%	15.3%
LDS/LGSS Flex	208.4%	0.0%
MLDS	-82.4%	3.5%
Total	11.4%	11.4%
Sources: Columbia "Average" ACOSS, RDK calculations		

As shown in Table IEc-SR1, there is little consistency between the results of the Company's "average" ACOSS and the Company's proposed base rate increases. Given the substantial shortfall in cost recovery from the flex rate customers, it should be expected that the rate increases for each class would be modestly higher than that needed to achieve cost-based rates (using the Company's own proposed ACOSS), unless constrained by gradualism. However, for the Rate R and SGS1 classes, the proposed increases are at or below the increase necessary to achieve cost-based rates. For SGS2, non-flex LDS, and MLDS, the Company's proposed increases far exceed that necessary for cost-based rates.

Only the increase for the SDS/LGSS class proposed by the Company would appear to be reasonably consistent with the Company's ACOSS method.

Thus, Ms. Strauss's rebuttal to the contrary, the Company is either not following the cost dictates of its ACOSS, or it is making other unspecified judgmental adjustments.

Q. What are your comments regarding Mr. Plank's rebuttal testimony?

A. My responses are as follows:

- Mr. Plank is correct that the Company's proposed increase for Rate LDS non-flex rate customers is materially higher than the average class percentage increase reported by Columbia. Table IEc-SR2 below shows the various proposed increases for non-flex rate LDS customers among the parties.

- Mr. Plank is *not* correct that the $2.13 million increase proposed by the Company for non-flex rate Rate LDS customers would all apply to the volumetric charge. Some $345,000 of that amount is related to the Company's proposed charges for the C&I Network, which would be imposed as a network charge. For a Company of Knouse's size (400,000 Dth/year), I calculate Company's proposed base rate increase to be 14.2 percent, modestly lower than that for the average non-flex rate LDS customer.

- Mr. Plank is correct that non-flex rate customers will be subject to DSIC charges if a DSIC goes into effect after Columbia has exceeded the baseline investment amount approved in this proceeding. Of course, all other regular rate customers will also be subject to the DSIC. For example, under Columbia's proposed rates, a 5 percent DSIC would increase base distribution rates for small general service (SGS1) customers by 29 cents per Dth, while increasing Rate LDS base distribution rates by 8 cents per Dth.

- Mr. Plank is correct that the Company does not propose to increase the Rate LDS customer charge, and that rate design proposal tends to increase the impact on larger customers relative to an across-the-board increase. However, if the effect of the C&I Network charge is ignored, the Company has no cost basis for increasing the customer charges for the Rate LDS class. Excluding C&I Network effects, customer-related costs for the LDS/LGSS class are approximately $1,050 per customer per month.[3] As Columbia's Rate LDS customer charges are already well in excess of that amount even for the smallest-sized Rate LDS customers, the customer charges are already excessive. Thus, larger customers like Knouse are already being subsidized by smaller customers within the class.

- I am sympathetic to Mr. Plank's concern that Knouse would be subject to a large base distribution rate increase under any of the proposals offered in this proceeding, except that advanced by Mr. Crist representing Penn State. These increases, however, are generally based on the cost allocation methods chosen by the various analysts, which themselves are based in part on varying interpretations of Commission precedent. Table IEc-SR2 below shows the rate increase necessary to bring the revenues for the non-flex rate LDS customer sub-class into line with allocated costs.[4]

[3] Note that the customer component of costs for Rate LDS is only slightly affected by the difference between the P&A and the CD cost allocation methods, because the customer-related mains costs assigned to Rate LDS is very small.

[4] In preparing this table, I relied on my cost allocation studies, as these are the only studies which (a) segregate flex rate and non-flex rate customers for the LDS class, and (b) exclude the C&I Network charges. Mr. Plank agrees that the C&I Network charges are not appropriate at this time.

Table IEc-SR2
Implications of Alternative Cost Allocation Methods for Rate Increases to Rate LDS Non-Flex Rate Customers

Cost Allocation Method	Non-Flex LDS Increase to Cost Based Rates	Supporting Party	Proposed Increase to Non-Flex LDS
CD Method	-60.1%		
P&A Method	62.0%	I&E	15.3%
P&A OCA (Traditional)	122.8%	OCA	17.7%
50/50 CD/P&A	1.0%	Columbia	15.3%
25/75 CD/P&A	31.5%	OSBA	22.8%
50/50 CD/P&A*	1.0%	OSBA Alt.	1.1%
None Specified**		Penn State	6.8%

* Revenue allocation presented in OSBA rebuttal testimony if 50/50 CD/P&A ACOSS weighting method is adopted.

** Based on Mr. Crist's proposed base rate increase of $876,000, plus $345,000 for the C&I Network proposed by the Company.

Sources: RDK Workpapers

Table IEc-SR2 shows that the differences in cost allocation results for the non-flex rate LDS customers far exceed the differences in the proposed rate increases. Moreover, it highlights some of the peculiarities of the parties' positions.

First, despite the fact that the 50/50 weighting of cost allocation methods implies that a minimal increase for these customers is appropriate, the Company proposes to assign a significant rate increase. The Company has yet to explain its thinking in this respect, other than to argue that a rate increase is justified on a total class basis (i.e., including flex rate customers).

Second, despite supporting a cost allocation method that would imply a need for a more than 60 percent increase, I&E proposes no change to the Company's proposal. It is unusual to find parties so far apart on cost allocation methodology and yet in full agreement on the magnitude of the increase for regular rate customers.

Third, despite supporting a cost allocation method which would imply the need for a more than 100 percent increase to Rate LDS regular rates, OCA proposes an increase of about 17.7 percent that is about 1.55 times the system average.

Thus, the unfortunate fact is that the longer term rate increases that the Rate LDS class will face will likely remain highly dependent on the cost allocation method chosen by the Commission.

Q. At page 3, Mr. Magnani claims that you are attempting to re-litigate the issue of whether the C&I Network must be installed pursuant to the Commission's Order at Docket No. R-2017-2586190. Is that an accurate representation of your position?

A. No. First, the issue of whether the C&I Network was economically justified was raised by the Company in its filed case, and I was responding to that testimony.[5] Second, in my direct testimony, I acknowledged that this matter may have been resolved, and presented my recommendations if that was the Commission's decision.[6] I did so because, to my non-legal mind, the settlement language from the last base rates proceeding is murky. Specifically, the settlement of the last base rates case on this issue included the language:

> Columbia further agrees to propose that it install, own, operate and maintain all equipment, including telephonic or similar technology, ***provided that Columbia is granted rate recovery of reasonable and prudent capital and operating and maintenance costs*** to own, operate and maintain the capability to obtain daily information from such customers. [emphasis added]

Since the Commission did not approve a rate recovery mechanism at Docket No. R-2017-2586190, it can presumably be argued that the Company is not required to install the system as recovery has not yet been approved, particularly since the costs have increased since the time of the Commission's review.[7] I am advised by OSBA counsel that it will present its legal evaluation of this issue in its briefs.

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[5] See Columbia Statement No. 10 at 22-27.

[6] See OSBA Statement No. 1 at 11.

[7] In fact, the Company makes this argument in its rebuttal testimony. See Columbia Statement No. 10-R at page 37 and again at page 38.

As a general regulatory matter, however, it is unwise in my view to approve a significant increase in utility spending without an accompanying bill impact analysis. As I indicated in my direct testimony, and the Company confirms in its rebuttal, the cost recovery mechanism for this system will have a significant financial impact on the smaller customers who would be obligated to pay for this system, and could cause them to switch to utility gas supply or to competitive alternatives. Thus, I conclude that there are sound practical reasons why the prudence of the C&I Network should be assessed when rate impact information is available.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2018-2647577**
	:	**Docket No. C-2018-3000773**
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

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

The Honorable Jeffrey A. Watson
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place, Suite 220
301 5th Avenue
Pittsburgh, PA 15222
jeffwatson@pa.gov

Lauren Burge, Esquire
Hayley Dunn, Esquire
Darryl Lawrence, Esquire
Office of Consumer Advocate
555 Walnut Street, 5th Floor
Harrisburg, PA 17101
LBurge@paoca.org
HDunn@paoca.org
DLawrence@paoca.org
(Counsel for OCA)
(Email and Hand Delivery)

Dante Mugrace
Marlon Griffing
PCMG and Associates, LLC
22 Brookes Avenue
Gaithersburg, MD 20877
dmugrace@pcmgregcon.com
mgriffing@pcmgregcon.com
(Expert Witness for OCA)

Jerome D. Mierzwa
Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044
jmierzwa@exeterassociates.com
(Expert Witness for OCA)

Roger D. Colton
Fisher, Sheehan and Colton
34 Warwick Road
Belmont, MA 02478
roger@fsconline.com
(Expert Witness for OCA)

Erika L. McLain, Esquire
Bureau of Investigation & Enforcement
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
ermclain@pa.gov
(Counsel for BIE)
(Email and Hand Delivery)

Theodore J. Gallagher, Esquire
Meagan Bielanin Moore, Esquire
Columbia Gas of Pennsylvania, Inc.
121 Champion Way, Suite 100
Canonsburg, PA 15317
tjgallagher@nisource.com
mbmoore@nisource.com
(Counsel for Columbia Gas)

Michael W. Hassell, Esquire
Lindsay A. Berkstresser, Esquire
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101
mhassell@postschell.com
lberkstresser@postschell.com
(Counsel for Columbia Gas)

Todd S. Stewart, Esquire
Hawke McKeon & Sniscak LLP
100 North Tenth Street
Harrisburg, PA 17101
tsstewart@hmslegal.com
(Counsel for NGS Parties)

Joseph L. Vullo, Esquire
Burke Vullo Reilly Roberts
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com
(Counsel for Community Action Assoc. of PA)

Thomas J. Sniscak, Esquire
William E. Lehman, Esquire
Whitney E. Snyder, Esquire
Hawke McKeon & Sniscak, LLP
100 North Tenth Street
Harrisburg, PA 17101
tjsniscak@hmslegal.com
welehman@hmslegal.com
wesnyder@hmslegal.com
(Counsel for Pennsylvania State University)

James L. Crist
Lumen Group, Inc.
4226 Yarmouth Drive, Suite 101
Allison Park, PA 15101
JLCrist@aol.com
(Expert Witness for PSU)

Charis Mincavage, Esquire
Alessandra L. Hylander, Esquire
McNees Wallace & Nurick LLC
100 Pine Street, PO Box 1166
Harrisburg, PA 17108
cmincavage@mcneeslaw.com
ahylander@mcneeslaw.com
(Counsel for CII)

Patrick M. Cicero, Esquire
Kadeem G. Morris, Esquire
Elizabeth R. Marx, Esquire
Pennsylvania Utility Law Project
118 Locust Street
Harrisburg, PA 17101
pulp@palegalaid.net
(Counsel for CAUSE-PA)

Dan Clearfield, Esquire
Kristine Marsilio, Esquire
Eckert Seamans Cherin & Mellott, LLC
213 Market Street, 8th Floor
Harrisburg, PA 17101
dclearfield@eckertseamans.com
kmarsilio@eckertseamans.com
(Counsel for Direct Energy)

DATE: July 17, 2018

Sharon E. Webb

Sharon E. Webb
Assistant Small Business Advocate
Attorney I.D. No. 73995

VERIFICATION

Reference: OSBA Statement No. 1
Direct Testimony and Exhibits of Robert D. Knecht

OSBA Statement No. 1-R
Rebuttal Testimony and Exhibit of Robert D. Knecht

OSBA Statement No. 1-SR
Surrebuttal Testimony of Robert D. Knecht

Columbia Gas of Pennsylvania, Inc.

Docket Nos. R-2018-2647577

2018 Base Rates Proceeding

I, Robert D. Knecht, hereby state that the facts set forth herein above are true and correct to the best of my knowledge, information and belief and that I expect to be able to prove the same at a hearing held in this matter. I understand that the statements herein are made subject to the penalties of 18 Pa. C.S. §4904 (relating to unsworn falsification to authorities).

Date: July 30, 2018

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
	:	
v.	:	**Docket No. R-2018-2647577**
	:	**Docket No. C-2018-3000773**
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

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

The Honorable Jeffrey A. Watson
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Piatt Place, Suite 220
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Lauren Burge, Esquire
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Office of Consumer Advocate
555 Walnut Street, 5th Floor
Harrisburg, PA 17101
LBurge@paoca.org
HDunn@paoca.org
DLawrence@paoca.org
(Counsel for OCA)
(Email and Hand Delivery)

Dante Mugrace
Marlon Griffing
PCMG and Associates, LLC
22 Brookes Avenue
Gaithersburg, MD 20877
dmugrace@pcmgregcon.com
mgriffing@pcmgregcon.com
(Expert Witness for OCA)

Jerome D. Mierzwa
Exeter Associates, Inc.
10480 Little Patuxent Parkway
Suite 300
Columbia, MD 21044
jmierzwa@exeterassociates.com
(Expert Witness for OCA)

Roger D. Colton
Fisher, Sheehan and Colton
34 Warwick Road
Belmont, MA 02478
roger@fsconline.com
(Expert Witness for OCA)

Erika L. McLain, Esquire
Bureau of Investigation & Enforcement
400 North Street
Commonwealth Keystone Building
Harrisburg, PA 17120
ermclain@pa.gov
(Counsel for BIE)
(Email and Hand Delivery)

Theodore J. Gallagher, Esquire
Meagan Bielanin Moore, Esquire
Columbia Gas of Pennsylvania, Inc.
121 Champion Way, Suite 100
Canonsburg, PA 15317
tjgallagher@nisource.com
mbmoore@nisource.com
(Counsel for Columbia Gas)

Michael W. Hassell, Esquire
Lindsay A. Berkstresser, Esquire
Post & Schell, P.C.
17 North Second Street, 12th Floor
Harrisburg, PA 17101
mhassell@postschell.com
lberkstresser@postschell.com
(Counsel for Columbia Gas)

Todd S. Stewart, Esquire
Hawke McKeon & Sniscak LLP
100 North Tenth Street
Harrisburg, PA 17101
tsstewart@hmslegal.com
(Counsel for NGS Parties)

Joseph L. Vullo, Esquire
Burke Vullo Reilly Roberts
1460 Wyoming Avenue
Forty Fort, PA 18704
jlvullo@bvrrlaw.com
(Counsel for Community Action Assoc. of PA)

Thomas J. Sniscak, Esquire
William E. Lehman, Esquire
Whitney E. Snyder, Esquire
Hawke McKeon & Sniscak, LLP
100 North Tenth Street
Harrisburg, PA 17101
tjsniscak@hmslegal.com
welehman@hmslegal.com
wesnyder@hmslegal.com
(Counsel for Pennsylvania State University)

James L. Crist
Lumen Group, Inc.
4226 Yarmouth Drive, Suite 101
Allison Park, PA 15101
JLCrist@aol.com
(Expert Witness for PSU)

Charis Mincavage, Esquire
Alessandra L. Hylander, Esquire
McNees Wallace & Nurick LLC
100 Pine Street, PO Box 1166
Harrisburg, PA 17108
cmincavage@mcneeslaw.com
ahylander@mcneeslaw.com
(Counsel for CII)

Patrick M. Cicero, Esquire
Kadeem G. Morris, Esquire
Elizabeth R. Marx, Esquire
Pennsylvania Utility Law Project
118 Locust Street
Harrisburg, PA 17101
pulp@palegalaid.net
(Counsel for CAUSE-PA)

Dan Clearfield, Esquire
Kristine Marsilio, Esquire
Eckert Seamans Cherin & Mellott, LLC
213 Market Street, 8th Floor
Harrisburg, PA 17101
dclearfield@eckertseamans.com
kmarsilio@eckertseamans.com
(Counsel for Direct Energy)

DATE: August 24, 2018

Sharon E. Webb
Assistant Small Business Advocate
Attorney ID No. 73995