COMMONWEALTH OF PENNSYLVANIA

June 19, 2015

<u>E-mail and First Class Mail</u>

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place, Suite 220
301 5th Avenue
Pittsburgh, PA 15222

Re: Columbia Gas of Pennsylvania, Inc.
Docket No. R-2015-2468056

Dear Judge Long:

Enclosed please find the Direct Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1, with Exhibits IEc-1, IEc-2, and IEc-3, 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 have been served, as indicated.

Sincerely,

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

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Enclosures

cc: Robert D. Knecht
Parties of Record

OSBA Stmt. 1
R-2015-2468056
8-4-15
Harrisburg JB

OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2015-2468056
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Direct Testimony and Exhibits of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design
Customer Contribution Policy

Date Served: June 19, 2015

Date Submitted for the Record: ______________________

DIRECT TESTIMONY OF ROBERT D. KNECHT

1. Witness Identification and Summary of Conclusions

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) and 2014 (Docket No. R-2014-2406274). 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 2014 base rates proceeding, this testimony is substantially similar to my testimony at Docket No. R-2014-2406274.

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. I have not prepared an independent alternative to the Company's cost allocation studies in this proceeding. Although this testimony identifies a number of improvements that Columbia could potentially make to its cost allocation methods, I do not have sufficient information to make those improvements. Moreover, with respect to small business customers, I conclude that the results from any independent cost allocation study that I would perform would likely fall within the range defined by the Company's cost allocation analyses. I therefore rely on a weighted average of the two cost allocation studies presented by the Company.

2. The Company's revenue allocation is not fully consistent with its cost allocation results, in that the proposed progress toward achieving cost-based rates is unduly constrained by gradualism concerns. I therefore offer an alternative revenue allocation recommendation that is consistent with the Company's cost allocation analysis, to be implemented through a first dollar relief mechanism.

3. The Company's calculation of customer-related costs in its cost allocation studies is arithmetically incorrect. This error contributes to the Company's proposal to assign an excessive customer charge increase to small customers in the Small General Service rate classes. I recommend that a more moderate customer charge increase be applied for those classes, based upon my weighted average version of the Company's cost allocation studies and the arithmetic corrections.

4. The Company's proposal to bifurcate the commodity charge for Small General Service customers is not unreasonable, based on the cost information available at this time. However, as this proposal essentially splits the Small General Service class into two classes, Columbia should analyze the two sub-classes separately in future cost allocation studies.

5. The Company's proposals for changing the customer contribution policies for new residential customers will implicitly require existing residential customers and both new and existing small business customers to subsidize some new customers. This is a proposed change in established Pennsylvania regulatory policy, a matter on which I take no position. However, to the extent that the Commission does adopt this policy change, it should recognize that doing so has a negative impact on existing customers.

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, and now 2015. 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 last few years. 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)
R-2008-2011621	Sep-2008	$58.9	$41.7
R-2009-2149262	Sep-2010	$32.3	$12.0
R-2010-2215623	Sep-2011	$37.8	$17.0
R-2012-2321748	Jun-2014	$77.3	$55.3
R-2014-2406274	Dec-2015	$54.1	$32.5
R-2015-2468056	Dec-2016	$46.2	–

Columbia's relatively large proposed increase in the 2012 proceeding was due in part to the switch to using a fully forecasted test year, ending June 2014, thereby incorporating nearly three full years of (mostly forecast) capital expenditures in the mains replacement program since the prior base rates case. Nevertheless, the Company has come back with yet another large increase (approximately 13 percent of base distribution rates) in the current filing after a 12-month interval.

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 rate classes, to provide background to the cost allocation, revenue allocation and rate design issues.
- Section 3 briefly reviews my assessment of cost causation and Columbia's allocated cost of service studies ("ACOSSs").

- Section 4 addresses revenue allocation issues.
- Section 5 addresses rate design issues.
- Section 6 briefly addresses the Company's proposed changes to its customer contribution policies for new residential customers.

2. Review of Columbia's Non-Residential Rate Classes

Q. Before we get into the details of your analysis, can you summarize the rate classes under which businesses can 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 47 million of Columbia's total 81 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.

In this proceeding, the Company proposes that it not treat large general sales service ("LGSS") customers as a separate rate class for cost allocation purposes, and to include those customers with transportation customers of comparable size. The approach proposed in this proceeding is reasonably consistent with that used in the 2011 rate case, but not in Columbia's other rate cases. As I testified in the 2014 proceeding, I agree with the approach proposed in the 2011 proceeding and this proceeding. 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.

SGSS/SCD/SGDS ("Small General"): This group consists of three tariff schedules: Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD"), and Small General Distribution Service ("SGDS"). SGSS is sales service, SCD is retail "Choice" transportation service and SGDS is regular transportation service. Within the SGS/SGDS rate class group, some 71 percent of the customers and 60 percent of the load are in Rate SGSS. The average Small General customer size is about 411 Dth per year, which is a little less than five times the size of the average residential customer. The tariff sets an upper limit on Small General customers at 6,440 Dth per year. Overall, Small General customers represent about 32 percent of non-residential throughput.

SDS/LGSS ("Medium General"): This rate class group now includes both sales and transportation service customers, taking service under Rate Schedules LGSS and Small Distribution Service ("SDS"). 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 customer size of a little below 15,000 Dth per year. This rate class group represents about 15 percent of non-residential throughput.

LDS/LGSS ("Large General"): This class now 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 150,000 Dth per year. This rate class group represents about 41 percent of non-residential throughput. Some 45 percent of the LDS load is subject to "flex" distribution rates, set on a negotiated basis below the maximum tariff rate.

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 eleven Mainline customers identified by Columbia represent about 12 percent of non-residential throughput.

3. Cost Allocation

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.[2] 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

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

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

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.

In addition to class revenue requirement issues, an ACOSS provides 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. To its credit, the Company included working electronic versions of its ACOSSs and a substantial amount of supporting detail in its filing in this proceeding.

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. This debate has a significant impact on rate design for a number of reasons. First, mains costs are "joint use" costs, meaning that, for the most part, 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. 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.

Rather than take a firm position on this debate, the Company essentially picks two methods which are 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. Note that 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. In practice, however, undertaking such an analysis would likely be detailed, costly and time consuming. Few utilities attempt such an undertaking. While Columbia is no exception to this rule, I note that Columbia's ACOSS methodology takes a step in that direction in this proceeding, by sub-dividing its mains costs by operating pressure, and allocating each group of mains only to customers who take service from those mains.[3] I note also that Columbia generally indicates 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 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.[4]

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. In the current case, for example, the cost to serve the Large General Service class is $9.5 million in the CD ACOSS and $30.4 million in the P&A ACOSS, a difference of more than 3 to 1. Given this enormous uncertainty, and the reliance on models with obvious theoretical flaws, undertaking a main-by-main allocation method may very well be worth the effort.

Absent such 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?

[3] See Columbia Statement No. 7, Direct Testimony of Mr. Brian E. Elliott, pages 7 to 11.

[4] 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. 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.)

- 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 to connect one large customer. (This common sense argument is supported by some aggregate industry statistical analysis.[5]) 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.

Relatively recent Commission precedent indicates that the Commission has rejected the use of a customer component for gas distribution utilities.[6] 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.[7]

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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[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.

[6] 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.

[7] 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.[8] 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

[8] Unfortunately, I have not found any theoretically reasonable method for developing the load carrying capability of the minimum system.

applies 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.

Recent Commission precedent for gas utilities 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.

Q. Why do the CD ACOSS and the 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. Moreover, it 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 P&A ACOSS is generally most favorable to the smallest customers. The P&A ACOSS has no customer component at all, which is favorable to the smallest customers, as economies of scale are not reflected. Moreover, it 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 an independent version of a cost allocation study in this proceeding?

A. No, I have not. In the Company's 2012 base rates proceeding, I conducted a detailed review and developed independent ACOSSs. In the 2014, the Company addressed many of the issues that I identified in that analysis, although it did not address some others. In this proceeding, the Company has generally followed its practices from last year's rate case.

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 replacement cost into the mains classification analysis, by adjusting historical book costs for inflation, typically using Handy-Whitman gas mains cost construction indices.[9] However, in light of the substantial technological changes,

[9] 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.

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 represents 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. Columbia currently splits services into only two groups, namely those with diameters above and below 3 inches. The unit cost for services under 3 inches is $793 per service, and for services over 3 inches is $1,062 per service. Based on my review of the data provided by Columbia, the costs for services over 3 inches pretty clearly increase as service diameter increases, which is of course not surprising. Thus, at a minimum, Columbia is over-assigning costs to the smaller customers who use services over 3 inches in diameter, and under-assigning costs to the larger customers in that group. However, a significant problem is that over 99 percent of services costs are related to services below 3 inches in diameter, and the Company does not have cost accounts delineated by diameter. 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 allocating meters costs, the Company breaks its meters into four generic groups, based on the maximum flow rates, namely 0 to 500, 501 to 1,000, 1,001 to 1,500 and over 1,500 cubic feet per hour ("cf/h"). The Company then calculates the average book cost for a meter in each of these four categories, and applies that unit meter cost to the meter count of each type in each rate class. The major problems with this approach are twofold. First, the aggregation categories are fairly large, which creates averaging problems. For example, the over 1500 cf/h category of meters includes thousands of meters related to Small General Service customers, as well as most of the meters related to the very large MDS

customers.[10] It is unlikely that the meters cost for a Small General Service customer is the same as that for a huge MDS customer. Second, the cost pattern shown for the average costs is illogical. Specifically, Columbia reports meters costs as follows:

Under 500 cubic feet per hour:	$ 50 per meter
501 – 1,000 cubic feet per hour	$496 per meter
1,001 – 1,500 cubic feet per hour	$229 per meter
Over 1,500 cubic feet per hour	$449 per meter

In effect, the Company's data suggest that meters costs actually decline as customer load increases, a result that conflicts with normal utility meter cost patterns. In this light, the Company should consider a replacement cost approach for meters costing, which would produce a more reasonable costing result.

5. In the 2012 proceeding, I expressed concern that the design day demands for the larger customers in the SDS and LDS classes were understated. Based upon my review of the data provided by Columbia in this proceeding, I do not believe that the design day demands for those classes are understated in the current filing.

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 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.

4. <u>Revenue Allocation</u>

Q. What is revenue allocation?

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[10] Curiously, Columbia reports that 2 of the 11 MDS customers use meters in the 1000 to 1500 cf/h range. As 1500 cf/h translates to a maximum annual load of about 13,000 mcf, it is not clear how that result is consistent with Columbia's proof of revenues, which shows that the smallest MDS customers consume at least 54,000 Dth per year.

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.[11]

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?

[11] 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.

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, the STAS roll-in, Rider USP (universal service), Rider CC, the proposed Rider CAC (a proposed charge for administrative costs for transportation customers), 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). By including all of these factors, my revenue allocation numbers differ slightly from those presented by Company witness Mr. Mark Balmert in Columbia Statement No. 11.

In measuring percentage changes, I also include all non-purchased gas cost revenues, again producing values that are slightly different than those in Columbia's filing.

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

A. The Company generally subscribes to the principles that rates should be moved into line with allocated costs, subject to rate gradualism considerations. For its cost basis, the Company generally relies on its Average ACOSS methodology. The Company also proposes not to assign a rate decrease to the MDS class (although it would be justified based on allocated costs). In addition, although Mr. Balmert does not explicitly say so, 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.[12]

[12] The revenue shortfall in 2014 from Large General Service flex rate customers at present rates was approximately $3.5 million, of which roughly $1.5 million was related to "gas on gas competition." The flawed regulatory policy of allowing NGDCs to discount rates to customers in overlapping utility service territories and requiring other customers to pick up the shortfall is currently before the Commission at Docket Nos. P-2011-2277868 and I-2012-2320323.

Unfortunately, to evaluate progress toward cost-based rates the Company relies on the flawed "unitized rate of return" metric, which can falsely imply progress toward cost-based rates when none exists. Therefore, in presenting the Company's revenue allocation proposal in Table IEc-2 below, I have reported the dollar "cross-subsidies" at present and proposed rates based on the Company's Average ACOSS.

Table IEc-2
Summary of Columbia Revenue Allocation Proposal
($mm)

	Total	Residential	Small General	Medium General	Large General	MDS
Revenue Allocation						
Current Revenues	342.5	252.6	58.5	14.1	15.8	1.5
Increase	46.1	35.8	6.1	1.8	2.4	0.0
Increase%	13.4%	14.2%	10.5%	12.6%	15.1%	0.0%
Increase% Excluding Flex	13.7%	14.2%	10.5%	12.8%	19.7%	0.0%
Cost Implications (Columbia Average ACOSS)						
Cross-Subsidy Current	0.0	(10.3)	8.3	1.9	(1.3)	1.4
Cross-Subsidy Proposed	0.0	(7.8)	6.5	1.7	(1.7)	1.4
Reduction in Cross-Subsidy	0.0	2.5	1.8	0.2	(0.5)	0.0

Notes: Revenues include all tariff revenues except gas supply costs.
A negative cross-subsidy value indicates the class is receiving the subsidy.
Source: RDK Workpapers, file CPA 2016 CD-P&A COSS Replication.xlsx

As shown, the Company's revenue allocation proposal makes relatively modest progress in reducing class cross-subsidies, with the exception of the Large General Service class. However, for that class, the Company proposes a fairly large percentage increase for customers who are not subject to flex rates.

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

A. I believe that Columbia's proposal is directionally reasonable, but can be improved upon by increasing the progress toward cost-based rates.

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

A. I have, although I propose that the Company's revenue allocation be modified using a first dollar relief ("FDR") scaleback approach. In the FDR approach, some portion of any reduction in the Company's overall claimed revenue requirement is first allocated to one or more classes, typically to those classes that are providing cross-subsidies at the Company's proposed rates.

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 two reasons. First, in the Company's 2012 base rates proceeding, the results of my independent ACOSS 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. Second, 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. A copy of this ACOSS version is presented in Exhibit IEc-2.[13]

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.[14] Because retaining these customers should reduce the

[13] In preparing this exhibit, I relied on my working version of the Company's ACOSS, rather than the Company's model itself. My replication of the Company's model produced results which were very slightly different from those reported by the Company, resulting I believe from arithmetic rounding protocols.

[14] The SGS/SGDS 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 accepted the Company's proposed revenue allocation to that class, which produces a rate increase of 19.7 percent for the non-flex rate customers in the class, or roughly 1.5 times the system average increase.

Third, I accept the Company's proposal for a *de minimis* increase for Rate MDS, as the vast majority of loads are subject to negotiated rates. Because these revenues exceed allocated costs, this approach tends to reduce the impact of the shortfall from the Large General Service flex rate customers on the smaller customer classes.

Q. What, then, is your proposal for FDR?

A. At the Company's proposed rates, my weighted average ACOSS shows that the Residential class provides a cross-subsidy of about $2.8 million, and the Small General Service Class provides a cross-subsidy of about $3.2 million. I therefore recommend that the first $6.0 million of any reduction to the Company's proposed $46.1 million increase be split between the Residential and Small General Service rate classes to offset the Company's proposed increases. To keep it simple, I suggest that reductions up to the first $6.0 million be split evenly between those two classes. Thus, if the Company's proposed increase were reduced to $40.1 million, the Residential increase would be reduced from $35.8 to $32.8 million, and the Small General Service increase would be reduced from $6.1 to $3.1 million.

Any reductions in the Company's proposed revenue requirement below $40.1 million would then be applied using a proportional scaleback approach. Table IEc-3 below shows how a scaleback to a $32.0 million increase would be calculated.

Table IEc-3 RDK Proposed First Dollar Relief Scaleback Mechanism ($mm)						
	Total	Residential	Small General	Medium General	Large General	MDS
Current Revenues	342.5	252.6	58.5	14.1	15.8	1.5
CPA Proposed Increase	46.1	35.8	6.1	1.8	2.4	0.0
FDR	(6.0)	(3.0)	(3.0)			
Increase after FDR	40.1	32.8	3.1	1.8	2.4	0.0
Scaleback	(8.1)	(6.6)	(0.6)	(0.4)	(0.5)	(0.0)
Net Increase	32.0	26.2	2.5	1.4	1.9	0.0
Percent	9.3%	10.4%	4.3%	10.1%	12.1%	0.0%
Notes: Revenues include all tariff revenues except gas supply costs. Scaleback is allocated in proportion to "Increase after FDR."						

5. **<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 single commodity charge. All three classes face the same customer charges, with a lower charge for customers with annual load below 644 Dth, currently set at $21.25 per month, and a higher customer charge for larger customers, currently set at $48.00 per month. The SGSS and SCD classes pay the same commodity charge (currently $3.1385 per Dth), while the SGDS customers pay a slightly lower commodity charge (currently $2.8791 per Dth), to reflect the fact that these customers must provide their own gas in storage working capital.

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), the Rider CC charge, and will be subject to Rider CAC charges if the Company's proposal in this proceeding is approved.

In this proceeding, the Company proposes to modify the commodity charge structure such that it, like the customer charge, is set at a different level for customers with annual loads above and below 644 Dth per year.

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-4 below.

Table IEc-4
Columbia Proposed Small General Service Base Rate Design
($mm)

	Current Rate	Proposed Rate	Percent Increase
Rates SGSS and SCD			
Customer Charge < 644Dth/year	$21.25	$27.75	30.6%
>644 Dth/year	$48.00	$55.50	15.6%
Commodity Charge <644 Dth/year	$3.1385	$3.5027	11.6%
>644 Dth/year		$3.1427	0.1%
Rate SGDS			
Customer Charge < 644Dth/year	$21.25	$27.75	30.6%
>644 Dth/year	$48.00	$55.50	15.6%
Commodity Charge <644 Dth/year	$2.8791	$3.2846	14.1%
>644 Dth/year		$3.1196	8.4%
Notes:			

Q. Do you agree with these proposals, within the context of Columbia's proposed increase of $6.1 million for this class?

A. In part. The cost data available to me show that the volumetric cost for the larger customers within the class is lower than that for the smaller customers, by at least the 36 cents per Dth lower rate proposed by Columbia. Thus, bifurcating the commodity charge is justified on a cost basis. However, the customer charges proposed by Columbia exceed the customer-related costs allocated to the Small General Service classes in my weighted average ACOSS. I therefore conclude that the proposed customer charges are excessive.

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

A. I begin with my Weighted Average ACOSS, and determine the per-customer costs that are allocated using customer-based allocation factors. In preparing this analysis, I developed a separate Weighted Average ACOSS which segregates Small General Service customers between those below and above 644 Dth in annual consumption. While I do not currently have all of the allocators necessary to make this evaluation, I believe that the major cost factors are reasonably estimated.[15]

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.

Unfortunately, the customer-related costs within the small business rate classes can vary considerably, with smaller customers having less expensive meters, services and regulators than do large customers within the class. It is for this reason that gas distribution utilities, including Columbia, will often segregate the customer charge by customer size. However, without a detailed cost allocation analysis by size of customer, it is difficult to get a direct measure of the customer cost to service the smallest business customers.

Nevertheless, from a practical perspective, the customer-related cost to serve the smallest business customers is very similar to that for residential customers, and therefore can

[15] This analysis is detailed in my workpapers, which are available to an party upon request to the OSBA.

often be used as a proxy. This general assumption is reasonably borne out in my cost analysis, which shows a customer cost of $24.37 per customer per month for residential customers and $25.75 per customer per month for Small General Service customers with less than 644 Dth in annual consumption.

Q. Are there conceptual differences between your customer cost analysis and that presented by the Company?

A. Yes, there are three significant differences.

First, I relied on my Weighted Average ACOSS for developing the customer cost, consistent with my revenue allocation analysis. This approach implicitly classifies about 12.5 percent of mains costs as customer-related. In contrast, the Company's customer cost analysis uses a mains customer component of 46.4 percent.[16]

Second, 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.

Third, the Company's approach includes an arithmetic error in its allocation of customer-related mains costs. The Company incorrectly allocates customer-related mains cost on the basis of a weighted average of customer and demand allocation factors, rather than simply allocating customer costs on the basis of number of customers. This error tends to understate the customer-related costs for residential customers and overstate the customer cost for all other rate classes.

Q. Could you provide a simple example that depicts the implications of the Company's arithmetic error?

[16] For reasons unknown, Columbia uses the same classification factor for its customer cost analysis in its CD ACOSS and its Average ACOSS, even though the implied customer component in the ACOSS should be much lower. In addition, Columbia uses the classification factor for low pressure mains, which it then applies to all mains costs.

A. Yes. Consider a simple utility with 90,000 residential customers and 10,000 Commercial customers, but equal class peak demands. Assume that mains costs total $50 million, and a minimum system classification approach is used in which the customer component of costs is 30 percent. The arithmetically correct method for allocating the costs and deriving the customer component of costs is shown in Table IEc-5 below.

Table IEc-5 Simple Example of Mains Cost Classification and Allocation			
	Total	**Rate R**	**Rate C**
(1) Number of Customers	100,000	90,000	10,000
(2) Customer Allocator	100.0%	90.0%	10.0%
(3) Demand Allocator	100.0%	50.0%	50.0%
(4) Mains Costs ($mm)	$50.0		
(5) Customer Component ($mm)	$15.0	$13.5	$1.5
(6) Demand Component ($mm)	$35.0	$17.5	$17.5
(7) Allocated Mains Costs ($mm)	$50.0	$31.0	$19.0
(8) Mains Customer Cost (Line (5))	$15.0	$13.5	$1.5
(9) Per Customer ($ per customer)	$150	$150	$150

In this example, the customer component of mains costs is $15 million (30 percent of total), it is allocated between the classes based on number of customers, and, not surprisingly, the customer component of mains costs for each class is the same at $150 per customer. In this traditional method adding one customer to either class will increase the costs assigned to that class by $150.[17] It is therefore sensible to conclude that the customer charge for both Rate R and Rate C should reflect this $150 for the customer-component of mains costs, because this is how the costs are allocated.

[17] For example, increasing the Rate C customer count to 10,001 customers and reducing the Rate R customer count to 99,999 would result in $13,499,850 being allocated to Rate R and $1,500,150 being allocated to Rate C.

This is the method that, arithmetically, Columbia uses to *allocate* mains costs. In effect, Columbia follows the procedure as shown through row (7) of Table IEc-5. However, where Columbia departs from this approach is in its derivation of the customer component of costs, in rows (8) and (9) of Table IEc-5.

In the programming of its ACOSS, the Company has chosen not to separately allocate customer-related and demand-related mains costs, but rather simply constructs a weighted average mains cost allocation factor. In practice, this factor is a little more complicated than that shown in my example, but the concept and the implications are the same. Columbia derives a weighted average mains allocation factor based on applying different classification percentages and different customer and demand allocation factors to various types of mains. In my example, this is equivalent to deriving a weighted mains allocation factor based on total allocated costs, which is shown at Row (7) of Table IEc-5. However, rather than allocating customer costs using a customer allocator, Columbia applies that weighted allocation factor, based on both customer count and class demands, to the customer-related costs. Columbia's method is shown in Table IEc-6 below.

Table IEc-6
Simple Example of Mains Cost Classification and Allocation
Columbia Mains Customer Cost Method

	Total	Rate R	Rate C
(1) Number of Customers	100,000	90,000	10,000
(7) Total Mains Costs ($mm)	$50.0	$31.0	$19.0
(10) Weighted Mains Allocation Factor	100.0%	62.0%	38.0%
(11) Columbia Mains Customer Cost ($mm)	$15.0	$9.3	$5.7
(12) Per Customer	$150	$103	$570

Notes: Lines (1) and (7) match the lines in Table IEc-5.
Line (10) is derived from line (7), and applied to the customer-related costs in line (11).

As shown, because the Company applies a weighted average allocation factor to customer-related costs, it incorrectly concludes that the customer-related component of mains costs for the Rate C class of $570 per customer, compared to only $103 per customer for the Rate R class. However, as noted above, under Columbia's cost allocation method, whether it is Rate R or Rate C, will increase costs allocated to the class by $150. Thus, Columbia substantially overstates the customer-related component of mains costs for Rate C.

Q. In your experience, do any other utilities use Columbia's approach?

A. I do not recall any other utility using Columbia's approach. It is arithmetically incorrect.

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 in the Weighted Average ACOSS is $24.37 for the Residential class, $25.75 for the Small General Service class (under 644 Dth/year) and $44.69 for the Small General Service class (over 644 Dth/year). In light of this analysis, I propose to limit the customer charge for the smaller-sized customers to $24.00 per month, an increase of 12.9 percent, and to assign no increase to the current $48.00 customer charge for the larger Small General Service customers.

It should be noted, however, that if the Commission approves a cost allocation methodology with no customer component to cost, there is virtually no justification for any increase in the customer charge for the SGS/SGDS class. Thus, if the Commission rejects the use of an ACOSS with a customer component, I recommend that the increase assigned to the SGS/SGDS class (exclusive of the effects of the various riders) be fully recovered in the commodity charges.

Q. Do you have any other comments regarding cost allocation and rate design for the Small General Service class?

A. Yes. The Company's proposed rate design for this class essentially treats customers above and below 644 Dth per year as separate rate classes, with separate customer charges and separate commodity charges. Note especially that the Company has no proposed a traditional declining block rate as customers transition from under 644 Dth/year to over 644 Dth per year – it has proposed wholly different customer and commodity charges. From a practical perspective, these customers are now in separate

rate classes. As such, the Company should segregate these two groups in future cost allocation analyses. In the absence of such an analysis, it will be impossible to set reasonable differentials for either the customer charge or the commodity charges within this rate class.

6. Customer Investment Policy

Q. Why do utilities have customer investment policies?

A. In general, public utility rates are designed to recover the book costs incurred by utilities. In Pennsylvania, as in many jurisdictions, utility book costs are fully allocated to all rate classes, and these allocated costs represent a significant criterion for developing utility rates. As such, utility rates are generally designed to recover average book cost.

However, when a new customer takes service, that customer will generally (a) make use of certain existing system assets that are currently being paid for by existing customers, and (b) require some incremental investment on the part of the utility. For new customers, regulators often include an incremental cost consideration in rate design. In order to ensure that new customers do not unreasonably burden existing customers, most utilities have a policy that requires that the revenues from the new customer be at least sufficient, in present value terms, to cover the cost of the incremental investment. Where a new customer does not produce sufficient revenues, the utility generally requires that the customer make a contribution to offset the utility investment.

Under this policy, customers who do not need to make a contribution will implicitly cover all of the incremental costs incurred by the utility *plus* they make a contribution to existing system assets. However, if the utility's customer contribution policy is structured only to ensure that the new customer will cover incremental costs, a new customer who makes a contribution will effectively contribute nothing to existing system asset costs.

Thus, customer contribution policies reflect a balance between the economic advantages of pure incremental cost pricing and the equity advantages of requiring all customers to make some contribution to the existing network from which they benefit.

Q. What is Columbia's current policy?

A. Columbia currently follows a policy much as I described. The costs associated with attaching a new customer or group of customers is subjected to an economic test, which compares the present value of revenues to the incremental investment required. Where new revenues are not sufficient to cover the incremental investment, a customer contribution (or "deposit") is required. (See Section 8.2 of the tariff.) At the customer's option, a new residential customer can make the contribution up front, or it can pay the contribution over time through a series of payments under Rider NAS. Rider NAS is not available to non-residential customers.

Q. What changes to the customer contribution policy is Columbia proposing in this proceeding?

A. Columbia proposes the following changes to its policies:

- Columbia will generally extend mains by 150 feet per customer to attach new residential customers, without the need for an economic test;[18]

- In addition to the main extension, Columbia will generally install new service lines of up to 150 feet per customer to attach new residential customers, without the need for an economic test, in the geographic areas in which Columbia owns the service lines;

- In cases where more than 150 feet per new residential customer of main extension is required, the economic test will be performed, but based only on the cost of extending the main beyond 150 feet per new customer;

- For new residential customer attachments, where the economic test justifies an investment greater than that necessary, the Company would use the "excess" to contribute to a customer's investment in house plumbing.

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[18] Note Columbia will subject new residential customer additions to an economic test where extraordinary cost issues arise, such that the cost of 150 feet of main is much higher than normal.

Q. What is your understanding of Pennsylvania policy with respect to customer contributions?

A. In my experience, the Pennsylvania policy is that existing customers should not be required to subsidize the attachment of new customers. Although I am not an attorney, this understanding appears to be consistent with the provisions of Senate Bill No. 214 in the current legislative session of the General Assembly.

Q. Has Columbia offered any evidence that its proposed changes will continue to ensure that existing customers are not subsidized by new customers?

A. No, it has not. Columbia's proposal for a main extension policy is based simply on average road miles between residences in its service territory. Moreover, Columbia acknowledges that, in its existing system, the average mains distance per customer is well below 150 feet.[19]

Q. In your view, will the proposed policies essentially require that existing customers subsidize new customers?

A. While it is difficult to say for certain, I expect that, in at least some cases, new customers will be subsidized by existing customers. My reasoning is based on the following sequential evaluation of each of the proposed policies.

If I look only at the proposal for 150 feet of main per residential customer, the Company reports that average cost for such an expansion would be about $4,350. Based on simulating the Company's economic model that was provided to OSBA in the Rider NAS proceedings (at Docket No. R-2014-2407345), the proposed revenues from a new residential customer over 40 years would more than justify such an investment. Thus, by itself, that modification would not appear to result in significant cross-subsidies.

However, if the cost for 150 feet of service line is similar in magnitude to the main extension costs, a project which requires both 150 feet of main and 150 feet of service line per new residential customer would generally not pass muster under the Company's

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[19] See OSBA-I-23,(c) and (d).

current economic test. Thus, new customers with those requirements will generally be subsidized by existing customers.

Finally, the Company's proposal to apply the economic test only to costs incurred in excess of the 150 foot allowances will almost certainly require subsidies from existing customers. Consider the case of attaching a set of new customers for which a contribution is required under this proposed policy. The economic test will ensure only that the new customers are paying the full incremental cost of expanding the system beyond the 150 foot per customer allowance. The new customers will make no contribution to the existing system, and they will make no contribution to the cost related to the 150 feet per customer allowance. All costs related to the 150 foot allowance will be borne by existing customers.

Q. What are the implications of Columbia's proposal to contribute to costs incurred by new residential customers within their houses for plumbing, when the present value of future revenues exceeds the incremental attachment costs?

A. As a general matter, adopting such a policy inherently changes the underlying philosophy of a customer contribution policy. As I explained earlier, customer contribution policies represent something of a balancing act, requiring that all new customers cover their incremental costs and that some new customers also make a contribution to the costs for the existing system. By modifying the model to allow additional investments to be made within the new customers' residences, the Company will implicitly reduce or potentially eliminate the contribution of new customers to the existing system, from which they benefit.

However, I note that the Company proposes that it will book any contribution to new customer's in-house plumbing as an O&M expense. Thus, this policy change will only reduce the contribution to existing system assets if these O&M costs are reflected in rates. In the current filing, it is my understanding that no such O&M costs are included in the Company's test year revenue requirement. Thus, as long as Columbia agrees that no such O&M costs will be included in future rate case revenue requirements, the policy will not have a negative impact on existing ratepayers.

Q. Mr. Knecht, your evaluation of these proposals focuses on the tradeoff between existing customers and new customers. If these policies apply only to residential customers, are existing small business customers affected by these policy changes?

A. As proposed by the Company, they are. The Company indicates that it has no intention of segregating the costs and revenues associated with this policy and assigning them solely to the residential class.[20] Thus, the new costs will be added to rate base, and allocated to all rate classes using the various costing methods discussed earlier. The new revenues will be credited to the residential class. If rates continue to be set based primarily on allocated costs, this normal rate design mechanism will implicitly result in some of the excess costs being absorbed by non-residential customers.

Q. Do you have a recommendation regarding these policies?

A. No, I do not. The proposed policies are "feel-good" policies, designed to achieve the admirable aim of expanding natural gas service to more residential customers in Pennsylvania. Moreover, the policies at least partly simplify the customer contribution issue, by eliminating the need for a detailed economic test in certain circumstances.

Unfortunately, someone needs to pay to attach the new customers, with the three obvious options being the new customers, the existing customers, and the utility. For the reasons detailed herein, Columbia's proposal will shift the cost requirement from new customers to existing customers. My view is that these Company's modifications represent a significant change in statewide regulatory policy, and the Commission should recognize that as such if it chooses to adopt the Company's proposals.

Q. Does this conclude your direct testimony?

A. Yes, it does.

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[20] OSBA-I-23(f).

EXHIBIT IEc-1

RÉSUMÉ AND EXPERT TESTIMONY LIST

FOR

ROBERT D. KNECHT

IEc

INDUSTRIAL ECONOMICS, INCORPORATED

ROBERT D. KNECHT

Robert D. Knecht specializes in the practical application of economics, finance and management theory to issues facing public and private sector clients. Mr. Knecht has more than thirty years of consulting experience, focusing primarily on the energy, metals, and mining industries. He has consulted to industry, law firms, and government clients, both in the U.S. and internationally. He has participated in strategic and business planning studies, project evaluations, litigation and regulatory proceedings and policy analyses. His practice currently focuses primarily on utility regulation, and he has provided analysis and expert testimony in numerous U.S. and Canadian jurisdictions. Mr. Knecht also served as Treasurer of IEc from 1996 through 2010, and was responsible for the firm's accounting, finance and tax planning, as well as administration of the firm's retirement plans, during that period.

Mr. Knecht's consulting assignments include the following projects:

- For the Pennsylvania Office of Small Business Advocate, Mr. Knecht provides analysis and expert testimony in industry restructuring, base rates and purchased energy cost proceedings involving electric, steam and natural gas distribution utilities. Mr. Knecht has analyzed the economics and financial issues of electric industry restructuring, stranded cost determination, fair rate of return, claimed utility expenses, cost allocation methods and rate design issues.
- For industrial customers in Québec, Mr. Knecht has prepared economic analysis and expert testimony in regulatory proceedings regarding cost allocation, compliance with legislative requirements for cross-subsidization, and rate design.
- For the New Brunswick Public Intervenor, Mr. Knecht has prepared expert testimony regarding electric and gas utilities, on various regulatory issues, including revenue requirements, amortization methods, system expansion economics, cost allocation, and rate design
- For independent power producers and industrial customers in Alberta, Mr. Knecht has provided analysis and expert testimony in a variety of electric industry proceedings, including industry restructuring, cost unbundling, stranded cost recovery, transmission rate design, cost allocation and rate design.
- As a participant on various international teams of experts, Mr. Knecht has prepared the economic and financial analysis for industry restructuring studies involving the steel and iron ore industries in Venezuela, Poland, and Nigeria.
- For the U.S. Department of Justice and for several private sector clients, Mr. Knecht has prepared analyses of economic damages in a variety of litigation matters, including ERISA discrimination, breach of contract, fraudulent conveyance, natural resource damages and anti-trust cases.
- Mr. Knecht participates in numerous projects with colleagues at IEc preparing economic and environmental analyses associated with energy and utility industries for the U.S. Environmental Protection Agency and other private and public entities.

Mr. Knecht holds a M.S. in Management from the Sloan School of Management at M.I.T., with concentrations in applied economics and finance. He also holds a B.S. in Economics from M.I.T. Prior to joining Industrial Economics as a principal in 1989, Mr. Knecht worked for seven years as an economic and management consultant at Marshall Bartlett, Incorporated. He also worked for two years as an economist in the Energy Group of Data Resources, Incorporated.

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ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010 TO 2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
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	March 2015	l'Association des Consommateurs de Gaz	Distribution cost allocation
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	Energy 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

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010 TO 2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
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
Matter 225	New Brunswick Energy & Utilities Board	Energy 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").

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010 TO 2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
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.
R-2013-2341604	Pennsylvania Public Utility Commission	Peoples TWP	March 2013	Pennsylvania Office of Small Business Advocate	Retainage rates, design day demand forecast, allocation of demand costs, recovery of other gas costs
R-2013-2341534	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2013	Pennsylvania Office of Small Business Advocate	Unaccounted for gas, retainage.
R-2012-2333993	Pennsylvania Public Utility Commission	Philadelphia Gas Works	February 2013	Pennsylvania Office of Small Business Advocate	Gas purchase cost unbundling, uncollectible cost unbundling
R-2012-2321748	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	January 2013	Pennsylvania Office of Small Business Advocate	Cost of capital, cost allocation, revenue allocation, gas procurement cost unbundling, rate design
R-2012-2327529	Pennsylvania Public Utility Commission	Peoples TWP	December 2012	Pennsylvania Office of Small Business Advocate	Gas purchase cost unbundling, price to compare
R-2012-2314235 R-2012-2314224 R-2012-2314247	Pennsylvania Public Utility Commission	UGI Utilities Gas Division UGI Penn Natural Gas UGI Central Penn Gas	October 2012	Pennsylvania Office of Small Business Advocate	Gas purchase cost unbundling, reconciliation, migration rider
P-2012-2302074	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2012	Pennsylvania Office of Small Business Advocate	Default service procurement, rate design, reconciliation, working capital cost treatment.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010 TO 2015

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
P-2011-2256365	Pennsylvania Public Utility Commission	PPL Electric Utilities	November 2011	Pennsylvania Office of Small Business Advocate	Default service reconciliation

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010 TO 2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
Matter No. 132	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	October 2011	New Brunswick Public Intervenor	Revenue requirement, cost forecasting, system expansion economic test, regulatory deferral test, filing requirements.
R-2010-2161694 on Remand	Pennsylvania Public Utility Commission	PPL Electric Utilities	August 2011	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables
R-2011-2238943, R-2011-2238943, R-2011-2238949,	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division), UGI Central Penn Gas UGI Penn Natural Gas	July 2011	Pennsylvania Office of Small Business Advocate	Design day demand, mandatory capacity assignment, sharing mechanisms
C-2011-2245906, M-2011-2243137	Pennsylvania Public Utility Commission	PPL Electric Utilities	July 2011	Pennsylvania Office of Small Business Advocate	Reconciliation of default service costs and revenues
P-2011-2218683, P-2011-2224781	Pennsylvania Public Utility Commission	West Penn Power Company	April, May 2011	Pennsylvania Office of Small Business Advocate	Critical peak pricing, time-of-use pricing
R-2010-2214415	Pennsylvania Public Utility Commission	UGI Central Penn Gas	April 2011	Pennsylvania Office of Small Business Advocate	Equity cost of capital, cost allocation, revenue allocation, non-residential rate design, EE&C cross-subsidies and cost recovery, natural gas vehicle subsidies
R-2010-2215623, R-2010-2201974	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	April 2011	Pennsylvania Office of Small Business Advocate	Cost of equity capital, cost allocation, revenue allocation, BTU adjustment mechanism, rate design, DSIC
NBEUB 2010-017	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	April 2011	New Brunswick Public Intervenor	Cost- and market-based ratemaking, transition mechanism
M-2010-2210316	Pennsylvania Public Utility Commission	UGI Utilities, Electric Division	March 2011	Pennsylvania Office of Small Business Advocate	Energy efficiency plan cost recovery, conservation development rider
A-2010-2213893, et al.	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	February 2011	Pennsylvania Office of Small Business Advocate	Asset valuation, reasonableness of proposed affiliate transaction

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010 TO 2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
M-2009-2123944	Pennsylvania Public Utility Commission	PECO	January 2011	Pennsylvania Office of Small Business Advocate	Dynamic pricing cost allocation and rate design
NBEUB 2010-007	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	December 2010	New Brunswick Public Intervenor	Allowable costs, O&M capitalization policy, expansion cost effectiveness, incentive mechanisms
R-3740-2010	Régie de l'énergie, Québec	Hydro Québec Distribution	December 2010	AQCIE/CIFQ	Pension cost reconciliation, cross-subsidies, rate design
P-2010-2158084	Pennsylvania Public Utility Commission	West Penn Power Company	November 2010	Pennsylvania Office of Small Business Advocate	Transmission service charge, reconciliation timing
P-2010-2194652	Pennsylvania Public Utility Commission	Pike County Light & Power	November 2010	Pennsylvania Office of Small Business Advocate	Electric default service procurement, customer education
A-2010-2176520, A-2010-2176732	Pennsylvania Public Utility Commission	Allegheny Power/FirstEnergy Corporation	September 2010	Pennsylvania Office of Small Business Advocate	Implications of proposed merger for default service
App. No. 1605961, Proceeding ID 530	Alberta Utilities Commission	Alberta Electric System Operator	August 2010	BC Hydro	Transmission rate design
R-2010-2167797	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	July 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables, rate of return
R-2010-2172933, R-2010-2172922, R-2010-2172928	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division), UGI Central Penn Gas UGI Penn Natural Gas	July 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, unaccounted-for gas, retainage
NBEUB 2010-002	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	June 2010	New Brunswick Public Intervenor	Cost allocation, rate design, deferral costs
R-2010-2161694	Pennsylvania Public Utility Commission	PPL Electric Utilities	June 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, purchase of receivables

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2010 TO 2015

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2010-2161920	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	June 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, retainage rates, gas price forecasting
R-2009-2149262	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2010	Pennsylvania Office of Small Business Advocate	Cost allocation, rate design, rate of return
P-2009-2145498	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division)	April 2010	Pennsylvania Office of Small Business Advocate	Merchant function charge, purchase of receivables
R-2010-2157062	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs
NBEUB 2009-017	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	March 2010	New Brunswick Public Intervenor	Cost allocation, deferral costs
R-2009-2139884	Pennsylvania Public Utility Commission	Philadelphia Gas Works	March 2010	Pennsylvania Office of Small Business Advocate	Revenue requirement, cost allocation, rate design, DSM program
R-2010-2150861	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs
R-2009-2145441	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil Company	March 2010	Pennsylvania Office of Small Business Advocate	Purchased gas costs, unaccounted-for gas, retainage
P-2010-2099333	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	February 2010	Pennsylvania Office of Small Business Advocate	Purchase of receivables

Note: Dates shown reflect submission date for direct testimony.

EXHIBIT IEc-2

RDK WEIGHTED AVERAGE ACOSS

Columbia Gas of Pennsylvania

EXHIBIT IEc-2: RDK Weighted Average Customer Demand/Peak-and-Average COSS

FY Ending December 31, 2016 ($000)

Summary of COSS	Total	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
Present Rates Summary							
Sales Customer Revenues	398,558.7	303,828.7	86,434.3	-	6,864.6	1,139.1	292.01
Transport Customer Revenues	134,437.4	81,996.0	23,638.9	-	11,904.5	15,453.2	1,444.88
Miscellaneous Revenues	1,903.0	1,456.1	336.8	-	54.1	52.4	3.63
Total Revenue	**534,893.1**	**387,280.8**	**110,410.0**	-	**18,823.1**	**16,644.7**	**1,740.52**
Net Purchased Gas Cost	(190,473.8)	(133,198.0)	(51,541.1)	-	(4,656.5)	(812.0)	(272.14)
Net Revenue	**344,419.4**	**254,082.8**	**58,869.0**	-	**14,166.6**	**15,832.7**	**1,468.39**
Other Purchased Gas Costs	985.8	689.4	266.8	-	24.1	4.2	1.41
Storage and Transportation	500.0	366.5	121.8	-	9.3	1.6	0.70
Distribution O&M	60,000.0	41,904.7	10,455.8	-	2,991.9	4,640.5	7.20
Customer Accounts	35,306.6	33,738.0	1,481.8	-	48.5	35.2	3.16
Customer Service and Info.	10,984.1	10,829.1	152.6	-	1.9	0.4	0.05
Sales	696.8	635.1	60.7	-	0.8	0.2	0.02
A&G	68,826.5	50,638.7	11,079.5	-	2,807.3	4,292.0	8.86
Total O&M	**177,299.8**	**138,801.5**	**23,619.0**	-	**5,883.8**	**8,974.2**	**21.40**
Depreciation	54,751.3	38,863.5	9,421.4	-	2,522.3	3,924.2	19.94
Other Taxes	3,221.1	2,346.8	527.8	-	136.7	209.2	0.48
Operating Income Before Taxes	**109,147.2**	**74,071.0**	**25,300.8**	-	**5,623.7**	**2,725.1**	**1,426.56**
Income Taxes	(29,190.6)	(19,619.5)	(7,581.6)	-	(1,526.4)	124.2	(587.22)
ITC	360.2	250.6	63.6	-	17.9	28.0	0.12
Net Income	**80,316.8**	**54,702.1**	**17,782.8**	-	**4,115.1**	**2,877.3**	**839.47**
Rate Base	**1,325,130.9**	**914,035.4**	**240,865.4**	-	**66,522.6**	**103,326.1**	**381.46**
Class Rate of Return	***6.061%***	***5.985%***	***7.383%***	***#DIV/0!***	***6.186%***	***2.785%***	***220.067%***
CPA Proposed Rates Summary							
Sales Customer Revenues	427,884.[illegible]1	330,021.5	89,750.9	-	6,754.5	1,065.8	292.0
Transport Customer Revenues	151,168.[illegible]7	91,559.8	26,455.6	-	13,795.1	17,913.3	1,444.9
Miscellaneous Revenues	2,016.8[illegible]	1,569.7	347.5	-	51.1	44.7	3.9
Total Revenue	**581,070.37**	**423,151.1**	**116,554.0**	-	**20,600.7**	**19,023.8**	**1,740.8**
Net Purchased Gas Cost	(190,479.76)	(133,198.0)	(51,541.1)	-	(4,656.5)	(812.0)	(272.1)
Net Revenue	**390,590.61**	**289,953.1**	**65,012.9**	-	**15,944.1**	**18,211.8**	**1,468.7**
Other Purchased Gas Costs	985.85	689.4	266.8	-	24.1	4.2	1.4
Storage and Transportation	499.95	366.5	121.8	-	9.3	1.6	0.7
Distribution O&M	60,603.00	42,372.8	10,536.1	-	3,015.2	4,671.8	7.2
Customer Accounts	35,306.63	33,738.0	1,481.8	-	48.5	35.2	3.2
Customer Service and Info.	10,984.14	10,829.1	152.6	-	1.9	0.4	0.1
Sales	696.76	635.1	60.7	-	0.8	0.2	0.0
A&G	68,826.47	50,638.7	11,079.5	-	2,807.3	4,292.0	8.9
Total O&M	**177,902.79**	**139,269.6**	**23,699.3**	-	**5,907.1**	**9,005.4**	**21.4**
Depreciation	54,751.33	38,863.5	9,421.4	-	2,522.3	3,924.2	19.9
Other Taxes	3,221.09	2,346.8	527.8	-	136.7	209.2	0.5
Operating Income Before Taxes	**154,715.41**	**109,473.1**	**31,364.4**	-	**7,378.0**	**5,073.0**	**1,426.9**
Income Taxes	(47,211.74)	(33,692.3)	(9,941.0)	-	(2,210.3)	(781.1)	(587.0)
ITC	360.24	250.6	63.6	-	17.9	28.0	0.1
Net Income	**107,863.90**	**76,031.4**	**21,487.1**	-	**5,185.5**	**4,320.0**	**839.9**
Rate Base	**1,325,130.92**	**914,035.4**	**240,865.4**	-	**66,522.6**	**103,326.1**	**381.5**
Class Rate of Return	**8.14%**	**8.318%**	**8.921%**	#DIV/0!	**7.795%**	**4.181%**	**220.189%**

Columbia Gas of Pennsylvania

EXHIBIT IEc-2: RDK Weighted Average Customer Demand/Peak-and-Average COSS

$000

Revenues	Alloc. Factor	Total	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
Current Revenues								
Sales Customer Revenues								
Base Revenue		193,569.6	154,667.1	36,418.0	-	2,148.0	316.6	19.9
USP Revenue		20,487.0	20,487.0	-	-	-	-	-
STAS		-	-	-	-	-	-	-
Rider CC Revenue		29.2	21.0	8.2	-	-	-	-
Flex Revenue		-	-	-	-	-	-	-
GPC Revenue		2,323.0	1,618.0	634.4	-	60.1	10.5	-
MFC Revenue		1,752.7	1,573.8	178.9	-	-	-	-
Gas Cost Revenue		180,397.3	125,461.9	49,194.8	-	4,656.5	812.0	272.1
Sub-Total Sales Revenue		**398,558.7**	**303,828.7**	**86,434.3**	-	**6,864.6**	**1,139.1**	**292.0**
Transport Customer Revenues								
Base Revenue		112,021.6	67,094.6	21,252.4	-	11,705.4	11,773.3	196.0
USP Revenue		7,157.9	7,157.9	-	-	-	-	-
STAS		0.0	-	-	-	-	-	0.0
Rider CC Revenue		12.7	7.3	5.4	-	-	-	-
Flex Revenue		5,162.7	-	34.8	-	199.1	3,679.9	1,248.9
Rider CAC Revenue		-	-	-	-	-	-	-
MFC Revenue		-	-	-	-	-	-	-
Gas Cost Revenue		10,082.4	7,736.1	2,346.3	-	-	-	-
Sub-Total Transport Revenue		**134,437.4**	**81,996.0**	**23,638.9**	-	**11,904.5**	**15,453.2**	**1,444.9**
Miscellaneous Revenue								
Forfeited Discount	FD	1,318.1	954.13	272.9	-	46.4	41.0	3.6
Misc. Revenues	C1	150.0	136.7	13.1	-	0.2	0.0	0.0
Rents	DP	144.3	100.3	25.4	-	7.2	11.3	0.0
Other	C1	290.6	264.9	25.3	-	0.3	0.1	0.0
Sub-Total Misc. Revenue		**1,903.0**	**1,456.1**	**336.8**	-	**54.1**	**52.4**	**3.6**
Total Current Revenues		**534,899.1**	**387,280.8**	**110,410.0**	-	**18,823.1**	**16,644.7**	**1,740.5**
CPA Proposed Revenues								
Sales Customer Revenues								
Base Revenue		222,383.6	179,812.3	40,216.6	-	2,083.6	251.3	19.8
USP Revenue		22,763.8	22,763.8	-	-	-	-	-
STAS		-	-	-	-	-	-	-
Rider CC		32.4	23.3	9.1	-	-	-	-
Flex Revenue		-	-	-	-	-	-	-
GPC Revenue		554.8	386.5	151.5	-	14.3	2.5	-
MFC Revenue		1,752.7	1,573.8	178.9	-	-	-	-
Gas Cost Revenue		180,397.3	125,461.9	49,194.8	-	4,656.5	812.0	272.1
Sub-Total Sales Revenue		**427,884.7**	**330,021.5**	**89,750.9**	-	**6,754.5**	**1,065.8**	**292.0**
Transport Customer Revenues								
Base Revenue		129,297.5	77,757.7	23,591.1	-	13,533.0	14,220.4	195.3
USP Revenue		5,652.0	5,652.0	-	-	-	-	-
STAS		-	-	-	-	-	-	-
Rider CC		14.1	8.1	6.0	-	-	-	-
Flex Revenue		5,162.7	-	34.8	-	199.1	3,679.9	1,248.9
Rider CAC Revenue		960.0	405.9	477.4	-	63.1	13.0	0.7
MFC Revenue		-	-	-	-	-	-	-
Gas Cost Revenue		10,082.4	7,736.1	2,346.3	-	-	-	-
Sub-Total Transport Revenue		**151,168.8**	**91,559.8**	**26,455.6**	-	**13,795.1**	**17,913.3**	**1,444.9**
Miscellaneous Revenue								
Forfeited Discount	FD	1,432.0	1,036.58	296.5	-	50.4	44.6	3.9
Misc. Revenues	C1	150.0	136.7	13.1	-	0.2	0.0	0.0
Rents	C1	144.3	131.5	12.6	-	0.2	0.0	0.0
Other	C1	290.6	264.9	25.3	-	0.3	0.1	0.0
Sub-Total Misc. Revenue		**2,016.9**	**1,569.7**	**347.5**	-	**51.1**	**44.7**	**3.9**
Total Proposed Revenues		**581,070.4**	**423,151.1**	**116,554.0**	-	**20,600.7**	**19,023.8**	**1,740.8**

Columbia Gas of Pennsylvania

EXHIBIT IEc-2: RDK Weighted Average Customer Demand/Peak-and-Average COSS

$000

Summary of Customer Costs at Proposed Rates	Total	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS/NSS
Production/Storage/Transport	6,347.4	5,623.5	654.9		34.7	29.3	5.0
Net Distribution Plant	552,737.5	493,311.0	54,832.3		2,378.8	1,838.5	376.9
General Plant	5,894.7	5,222.4	608.2		32.2	27.2	4.6
Gas In Storage	-	-	-		-	-	-
Deferred Taxes	(115,017.9)	(101,894.4)	(11,867.3)		(628.6)	(531.1)	(96.4)
Other Rate Base	(1,875.8)	(1,184.3)	(710.3)		9.3	9.2	0.3
Total Rate Base	**448,085.9**	**401,078.1**	**43,517.8**		**1,826.4**	**1,373.1**	**290.5**
Distribution Operating Exps.	20,803.2	18,133.1	2,249.6		206.6	209.4	4.5
Distribution Maintenance	4,508.0	3,894.0	452.4		73.6	85.3	2.7
Customer Accounts	10,613.1	9,658.0	940.7		11.6	2.5	0.3
Customer Service and IS	1,751.6	1,596.6	152.6		1.9	0.4	0.1
Sales	696.8	635.1	60.7		0.8	0.2	0.0
A&G	35,565.5	31,398.4	3,595.8		280.3	284.0	7.0
Depreciation	24,348.9	21,415.8	2,622.4		155.5	135.5	19.7
Other Taxes	1,653.4	1,444.8	176.7		15.6	15.8	0.4
Total Expenses	**99,940.5**	**66,148.7**	**7,549.0**		**465.7**	**438.4**	**27.5**
Income Taxes	15,842.6	14,180.6	1,538.6		64.6	48.5	10.3
Return	36,473.6	32,647.2	3,542.3		148.7	111.8	23.6
Total Revenue Requirement	**152,256.7**	**112,976.5**	**12,629.9**		**678.9**	**598.8**	**61.5**
Customer Count	423,809	386,310	36,921		467	100	11
Cost per Customer/Month	**$ 29.94**	**$ 24.37**	**$ 28.51**		**$ 121.15**	**$ 498.96**	**$ 465.69**

-Average COSS

			Demand							Customer						
Gross	Acc. Dep'n	Net Book	Total D	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS	Total C	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
25,650.5	(9,438.6)	16,211.8	9,864 4	5,652.5	2,204.9	-	771.1	1,235.8	-	6,347 4	5,623.5	654.9	-	34.7	29.3	5.0
6,188.9	(2,472.7)	3,716.1	3,716.1	2,724.0	905.5	-	69.4	12.1	5.2	-	-	-	-	-	-	-
-		-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6,135.0	(2,518.4)	3,616.6	3,174.3	1,818.9	709.5	-	248.1	397.7	-	442.3	403.8	38.0	-	0.4	0.1	-
1.2	(0.7)	0.5	-	-	-	-	-	-	-	0.5	-	-	-	-	-	0.5
503.5		503.5	441.9	253.2	98.8	-	34.5	55.4	-	61.6	56.2	5.3	-	0.1	0.0	-
4.0		4.0	3.5	2.0	0.8	-	0.3	0 4	-	0.5	0 4	0.0	-	0.0	0.0	-
3,330.6	(880.8)	2,448.7	2,149.2	1,231.6	480 4	-	168.0	269.3	-	299.5	273.4	25.7	-	0.3	0.1	-
27.2	(1.2)	26.0	-	-	-	-	-	-	-	26.0	-	-	-	-	-	26.0
87.7	(73.9)	13.8	-	-	-	-	-	-	-	13.8	-	3.4	-	4.6	5.8	-
9,396.0	(2,031.7)	7,364.3	4,481.0	2,567.7	1,001.6	-	350.3	561 4	-	2,883.4	2,554.5	297.5	-	15.8	13.3	2.3
1,125.9	(1,125.9)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
16 5	(6.5)	10.0	8.8	5.0	2.0	-	0.7	1.1	-	1.2	1.1	0.1	-	0.0	0.0	-
1,247,518.5	(185,262.9)	1,062,255.7	932,336.6	534,252.2	208,398.0	-	72,882.4	116,804.1	-	129,919.0	118,607.8	11,164.2	-	116.6	30.4	-
195.3	(139.5)	55.7	-	-	-	-	-	-	-	55.7	-	-	-	-	-	55.7
40,284.9	(9,991.2)	30,293.7	26,588.6	15,235.9	5,943.1	-	2,078.5	3,331.0	-	3,705.1	3,382.5	318.4	-	3.3	0.9	-
1.2	(0.7)	0.5	-	-	-	-	-	-	-	0.5	-	-	-	-	-	0.5
454,989 4	(113,033.7)	341,955.7	-	-	-	-	-	-	-	341,955.7	314,452.2	26,802.5	-	533.5	167.6	-
37.6	(23.5)	14.2	-	-	-	-	-	-	-	14.2	-	-	-	-	-	14.2
36,181.3	(15,981.7)	20,199.6	-	-	-	-	-	-	-	20,199.6	15,088.9	4,871.9	-	179.8	55.8	3.2
23,761.1	(8,699.0)	15,062.1	-	-	-	-	-	-	-	15,062.1	11,251.2	3,632.8	-	134.1	41.6	2.4
36,486.3	(11,922.9)	24,563 4	-	-	-	-	-	-	-	24,563.4	18,348.6	5,924.5	-	218.6	67.8	3.9
11,597.2	(3,551.1)	8,046.1	-	-	-	-	-	-	-	8,046.1	7,296 4	730.6	-	15.6	3 4	-
3,864.8	(2,978.9)	885.8	-	-	-	-	-	-	-	885.8	803.3	80 4	-	1.7	0 4	-
5,504 7	(3,252.9)	2,251.8	-	-	-	-	-	-	-	2,251.8	-	552.7	-	752.2	946.9	-
299.3	(69.3)	230.0	-	-	-	-	-	-	-	230.0	-	-	-	-	-	230.0
1,190.0		1,190.0	-	-	-	-	-	-	-	1,190.0	-	292.1	-	397.5	500 4	-
38 4	(0.9)	37.5	-	-	-	-	-	-	-	37.5	-	-	-	-	-	37.5
3,209.1	(930.2)	2,278.9	1,386.7	794.6	310.0	-	108.4	173.7	-	892.3	790.5	92.1	-	4 9	4.1	0.7
1,885,786.7	(362,478.6)	1,523,308.1	970,570.6	556,161.2	216,944.1	-	75,871.2	121,594.1	-	552,737.5	493,311.0	54,832.3	-	2,378.8	1,838.5	376.9
27,403.5	(12,347.8)	15,055.7	9,160 9	5,249.4	2,047.7	-	716.1	1,147.7	-	5,894.7	5,222.4	608.2	-	32.2	27.2	4.6
1,945,029.5	(386,737.8)	1,558,291.7	993,512.0	569,787.1	222,102.1	-	77,427.8	123,989.7	5.2	564,979.7	504,156.9	56,095.4	-	2,445.7	1,895.0	386.6
		3,794.7	3,794.7	2,781.5	924 6	-	70.8	12.4	5.3	-	-	-	-	-	-	-
		(163.5)	(163.5)	(119.8)	(39 8)	-	(3.1)	(0.5)	(0.2)	-	-	-	-	-	-	-
		649.0	394.9	226.3	88.3	-	30.9	49.5	-	754.1	225.1	26.2	-	1.4	1.2	0.2
		58,489.3	58,489 3	42,873.2	14,251.5	-	1,092.0	190.7	81 9	-	-	-	-	-	-	-
		2,107.0	1,022 4	591.7	230.1	-	77.6	123.0	0 1	1,084 6	958.6	109.0	-	8.3	8.4	0.2
			-	-	-	-	-	-	-	-	-	-	-	-	-	-
			-	-	-	-	-	-	-	-	-	-	-	-	-	-
		8,949.4	5,456.5	3,131.2	1,220 2	-	424 8	680.1	0 0	3,492.9	3,094 4	360.4	-	19.1	16.1	2.9
		(303,643.3)	(185,132.6)	(106,240.1)	(41,400 7)	-	(14,414.7)	(23,075 7)	(1 4)	(118,510.8)	(104,988.8)	(12,227.7)	-	(647.7)	(547.3)	(99.3)
			-	-	-	-	-	-	-	-	-	-	-	-	-	-
		(3,131.6)	-	-	-	-	-	-	-	(3,131.6)	(2,294.6)	(837.0)	-	-	-	-
		(211.7)	(128.8)	(73.8)	(28.8)	-	(10.1)	(16.1)	-	(82.9)	(73 4)	(8.6)	-	(0.5)	(0 4)	(0.1)
-	-	(233,160.8)	(116,267.1)	(56,829.8)	(24,754.6)	-	(12,731.6)	(22,036.7)	85.7	(116,893.7)	(103,078.8)	(12,577.6)	-	(619.4)	(521.9)	(96.0)
1,945,029.5	(386,737.8)	1,325,130.9	877,045.0	512,957.3	197,347.6	-	64,696.2	101,953.0	90.9	448,085.9	401,078.1	43,517.8	-	1,826.4	1,378.1	290.5

ɛak-and-Average COSS

c-		Demand								Customer						
or	Total	Total D	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS	Total C	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
·	3,857.3	2,347.1	1,344.9	524.6	-	183.5	294.0	-	1,510.3	1,338.0	155.8	-	8.3	7.0	1.2
	164.9	164.9	120.8	40.2	-	3.1	0.5	0.2	-	-	-	-	-	-	-
)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
l	83.1	72.9	41.8	16.3	-	5.7	9.1	-	10.2	9.3	0.9	-	0.0	0.0	-
s	0.0	-	-	-	-	-	-	-	0.0	-	-	-	-	-	0.016
l		-	-	-	-	-	-	-	-	-	-	-	-	-	-
l		-	-	-	-	-	-	-	-	-	-	-	-	-	-
l*	85.1	74.7	42.8	16.7	-	5.8	9.4	-	10.4	9.5	0.9	-	0.0	0.0	-
	0.4	-	-	-	-	-	-	-	0.4	-	0.1	-	0.1	0.2	-
·	0.9	0.5	0.3	0.1	-	0.0	0.1	-	0.3	0.3	0.0	-	0.0	0.0	0.000
·	450.3	274.0	157.0	61.2	-	21.4	34.3	-	176.3	156.2	18.2	-	1.0	0.8	0.139
l	0.3	0.3	0.2	0.1	-	0.0	0.0	-	0.0	0.0	0.0	-	0.0	0.0	-
l	25,668.2	22,528.9	12,909.6	5,035.7	-	1,761.1	2,822.4	-	3,139.3	2,866.0	269.8	-	2.8	0.7	-
s	4.4	-	-	-	-	-	-	-	4.4	-	-	-	-	-	4.415
:	1,251.5	1,098.5	629.4	245.5	-	85.9	137.6	-	153.1	139.7	13.2	-	0.1	0.0	-
s	0.0	-	-	-	-	-	-	-	0.0	-	-	-	-	-	0.027
	12,923.6	-	-	-	-	-	-	-	12,923.6	11,884.2	1,013.0	-	20.2	6.3	-
s	1.0	-	-	-	-	-	-	-	1.0	-	-	-	-	-	0.971
	877.5	-	-	-	-	-	-	-	877.5	655.5	211.6	-	7.8	2.4	0.140
	1,748.0	-	-	-	-	-	-	-	1,748.0	1,305.8	421.6	-	15.6	4.8	0.280
	708.7	-	-	-	-	-	-	-	708.7	529.4	170.9	-	6.3	2.0	0.113
	300.1	-	-	-	-	-	-	-	300.1	272.2	27.3	-	0.6	0.1	-
	66.4	-	-	-	-	-	-	-	66.4	60.2	6.0	-	0.1	0.0	-
	236.0	-	-	-	-	-	-	-	236.0	-	57.9	-	78.8	99.2	-
s	10.5	-	-	-	-	-	-	-	10.5	-	-	-	-	-	10.475
	0.9	-	-	-	-	-	-	-	0.9	-	0.2	-	0.3	0.4	-
·	143.9	87.6	50.2	19.6	-	6.8	11.0	-	56.4	49.9	5.8	-	0.3	0.3	0.044
	44,561.05	24,137.4	13,831.3	5,395.2	-	1,886.9	3,024.0	-	20,423.6	17,938.2	2,217.4	-	134.1	117.3	16.6
·	1,532.8	932.6	534.4	208.5	-	72.9	116.8	-	600.1	531.7	61.9	-	3.3	2.8	0.5
	50,116.0	27,582.0	15,831.5	6,168.5	-	2,146.3	3,435.4	0.2	22,534.0	19,807.9	2,435.2	-	145.6	127.1	18.3

ak-and-Average COSS

c.		Demand							Customer						
or	Total	Total D	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS	Total C	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
	190,479.8	190,479.8	133,198 0	51,541.1	-	4,656.5	812.0	272.1	-	-	-	-	-	-	-
	431.0	431.0	301.4	116.6	-	10.5	1.8	0.6	-	-	-	-	-	-	-
.	554.8	554.8	388.0	150.1	-	13.6	2.4	0.8	-	-	-	-	-	-	-
	191,465.6	191,465.6	133,887.4	51,807.8	-	4,680.6	816.2	273.5	-	-	-	-	-	-	-
-															
	2.6	2.6	1.9	0.6	-	0.0	0.0	0.0	-	-	-	-	-	-	-
	8.4	8 4	6.2	2.1	-	0.2	0.0	0.0	-	-	-	-	-	-	-
	418.7	418.7	306.9	102.0	-	7.8	1.4	0.6	-	-	-	-	-	-	-
•	11.9	11.9	8.8	2.9	-	0.2	0.0	0.0	-	-	-	-	-	-	-
	6.9	6.9	5.1	1.7	-	0.1	0.0	0.0	-	-	-	-	-	-	-
	3.7	3.7	2.7	0.9	-	0.1	0.0	0.0	-	-	-	-	-	-	-
	17.0	17.0	12.4	4.1	-	0.3	0.1	0.0	-	-	-	-	-	-	-
	10.4	10.4	7.6	2.5	-	0.2	0.0	0.0	-	-	-	-	-	-	-
	11.2	11.2	8.2	2.7	-	0.2	0.0	0.0	-	-	-	-	-	-	-
	9.1	9.1	6.7	2.2	-	0.2	0.0	0.0	-	-	-	-	-	-	-
	500.0	500.0	366.5	121.8	-	9.3	1.6	0.7	-	-	-	-	-	-	-
D	9,498.5	5,491.5	3,146.8	1,227.5	-	429.3	688.0	-	4,007.0	3,487.1	427.8	-	44.4	46.7	1.1
!	294.3	258.2	148.0	57.7	-	20.2	32.4	-	36.0	32.9	3.1	-	0.0	0.0	0.0
;	14,496.8	9,322.1	5,341.8	2,083.7	-	728.7	1,167.9	-	5,174.7	4,748.1	415.2	-	7.2	2.2	2.0
!	613.6	538.5	308.6	120.4	-	42.1	67.5	-	75.1	68.5	6.4	-	0.1	0.0	0.1
	274.0	-	-	-	-	-	-	-	274.0	-	67.3	-	91.5	115.2	-
!	2,538.5	-	-	-	-	-	-	-	2,538.5	1,952.3	559.5	-	20.2	6.2	0.4
	5,575.0	-	-	-	-	-	-	-	5,575.0	5,126.6	437.0	-	8.7	2.7	-
D	6,779.3	3,919 4	2,245.9	876.1	-	306.4	491.0	-	2,859.9	2,488.8	305.3	-	31.7	33.3	0.8
D	623.6	360.5	206.6	80.6	-	28.2	45.2	-	263.0	228.9	28.1	-	2.9	3.1	0.1
	40,693.5	*19,890.3*	*11,397.6*	*4,445.9*	-	*1,554.9*	*2,491.9*	-	*20,803.2*	*18,133.1*	*2,249.6*	-	*206.6*	*209.4*	*4.5*
D	88.2	51.0	29.2	11.4	-	4.0	6.4	-	37.2	32.4	4.0	-	0 4	0.4	0.0
!	34.8	30.5	17.5	6.8	-	2.4	3.8	-	4.3	3.9	0 4	-	0.0	0.0	0.0
!	15,560.0	13,654.8	7,824.6	3,052.2	-	1,067.4	1,710.7	-	1,905.2	1,737.1	163.5	-	1.7	0.4	2.4
:	521.2	457.4	262.1	102.2	-	35.8	57.3	-	63.8	58.2	5.5	-	0.1	0.0	0.1
	185.0	-	-	-	-	-	-	-	185.0	-	45.4	-	61.8	77.8	-
	1,626.2	-	-	-	-	-	-	-	1,626.2	1,495.4	127.5	-	2.5	0.8	-
	245.0	-	-	-	-	-	-	-	245.0	183.0	59.1	-	2.2	0.7	0.0
D	1,046.0	604.8	346.5	135.2	-	47.3	75.8	-	441.3	384.0	47.1	-	4.9	5.1	0.1
	19,306.5	*14,798.5*	*8,479.9*	*3,307.8*	-	*1,156.8*	*1,854.0*	-	*4,508.0*	*3,894.0*	*452.4*	-	*73.6*	*85.3*	*2.7*
	60,000.0	34,688.8	19,877.6	7,753.7	-	2,711.7	4,345.8	-	25,311.2	22,027.1	2,702.0	-	280.2	294.7	7.2
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	836.8	-	-	-	-	-	-	-	836.8	762.7	72.9	-	0.9	0.2	0.0
	9,650.2	-	-	-	-	-	-	-	9,650.2	8,796.3	840.7	-	10.6	2.3	0.3
	89.5	-	-	-	-	-	-	-	89.5	65.6	23.9	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
:	4,450.4	4,450.4	4,093.9	356.5	-	-	-	-	-	-	-	-	-	-	-

eak-and-Average COSS

c		Demand								Customer						
or	Total	Total D	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS	Total C	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
'G	78.0	78.0	-	5.6	-	36.9	32.6	2.8	-	-	-	-	-	-	-
U	1,752.7	1,752.7	1,573.8	178.9	-	-	-	-	-	-	-	-	-	-	-
S	18,412.4	18,412.4	18,412.4	-	-	-	-	-	-	-	-	-	-	-	-
.	36.7	-	-	-	-	-	-	-	36.7	33.4	3.2	-	0.0	0.0	0.0
.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
	35,306.6	24,693.5	24,080.0	541.1	-	36.9	32.6	2.8	10,613.1	9,658.0	940.7	-	11.6	2.5	0.3
.	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
.	576.0	-	-	-	-	-	-	-	576.0	525.1	50.2	-	0.6	0.1	0.0
S	9,232.6	9,232.6	9,232.6	-	-	-	-	-	-	-	-	-	-	-	-
.	73.2	-	-	-	-	-	-	-	73.2	66.7	6.4	-	0.1	0.0	0.0
.	1,102.3	-	-	-	-	-	-	-	1,102.3	1,004.8	96 0	-	1.2	0.3	0.0
.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
.		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
	10,984.1	9,232.6	9,232.6	-	-	-	-	-	1,751.6	1,596.6	152.6	-	1.9	0.4	0.1
	677.3	-	-	-	-	-	-	-	677.3	617.3	59.0	-	0.7	0.2	0.0
	19.5	-	-	-	-	-	-	-	19.5	17.8	1.7	-	0.0	0.0	0 0
	696.8	-	-	-	-	-	-	-	696.8	635.1	60.7	-	0.8	0.2	0.0
1	4,579.3	2,222.1	1,285.9	500.2	-	168 6	267.3	0.1	2,357.2	2,083 4	236.9	-	18.1	18.3	0.5
1	2,524.3	1,224.9	708.8	275.7	-	93.0	147.4	0.1	1,299.3	1,148.5	130.6	-	10.0	10.1	0 3
1	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
1	47,926.0	23,256.4	13,458.0	5,234.6	-	1,764.8	2,797.7	1.4	24,669.5	21,804.9	2,479.0	-	189.3	191.5	4.9
1	213.0	103.3	59.8	23.3	-	7.8	12.4	0.0	109.6	96.9	11.0	-	0.8	0.9	0.0
1	3,443.2	1,670.8	966.9	376.1	-	126.8	201.0	0.1	1,772.4	1,566.5	178.1	-	13.6	13.8	0.4
	5,561.9	2,561.3	1,475.2	573.8	-	197.4	315.0	0.1	3,000.5	2,614.9	323.3	-	30.4	31.3	0.6
1	2,330.0	1,130.6	654.3	254.5	-	85.8	136.0	0.1	1,199.4	1,060.1	120.5	-	9.2	9.3	0.2
1	584.2	283.5	164.1	63.8	-	21.5	34.1	0.0	300.7	265.8	30.2	-	2.3	2.3	0.1
1	1,664.7	807.8	467.5	181.8	-	61.3	97.2	0.0	856.9	757.4	86.1	-	6.6	6.6	0.2
	68,826.5	33,260.9	19,240.3	7,483.7	-	2,527.0	4,008.0	1.9	35,565.5	31,398.4	3,595.8	-	280.3	284.0	7.0
	367,779.6	293,841.4	206,684.3	67,708.2	-	9,965.6	9,204.3	278.9	73,938.2	65,315.2	7,451.8	-	574.8	581.8	14.6

Columbia Gas of Pennsylvania

EXHIBIT IEc-2: RDK Weighted Average Customer Demand/Peak-and-Average COSS

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Income Taxes	Alloc. Factor	Total	RS/RDS	SGS/SGDS		SDS/LGSS	LDS/LGSS	MDS/NSS
Current Rates								
Revenues		534,899.1	387,280.8	110,410.0	-	18,823.1	16,644.7	1,740.5
O&M Expense		(367,779.6)	(271,999.5)	(75,160.0)	-	(10,540.4)	(9,786.2)	(293.5)
Depreciation Expense		(54,751.3)	(38,863.5)	(9,421.4)	-	(2,522.3)	(3,924.2)	(19.9)
Other Taxes		(3,221.1)	(2,346.8)	(527.8)	-	(136.7)	(209.2)	(0.5)
Operating Income		**109,147.2**	**74,071.0**	**25,300.8**	-	**5,623.7**	**2,725.1**	**1,426.6**
Statutory Adjustments	GP	(50,280.5)	(34,977.6)	(8,880.4)	-	(2,494.2)	(3,911.7)	(16.7)
Interest on Debt	RB	(34,320.9)	(23,673.5)	(6,238.4)	-	(1,722.9)	(2,676.1)	(9.9)
PA Bonus Depreciation	GP	(7,572.7)	(5,268.0)	(1,337.5)	-	(375.6)	(589.1)	(2.5)
NOL Deduction	GP	(5,091.9)	(3,542.2)	(899.3)	-	(252.6)	(396.1)	(1.7)
State Taxable Income		**11,881.1**	**6,609.8**	**7,945.2**	-	**778.3**	**(4,848.1)**	**1,395.8**
State Income Tax at 9.99%	9.99%	1,186.9	660.3	793.7	-	77.8	(484.3)	139.4
State Deferred Income Tax	GP	(51.1)	(35.5)	(9.0)	-	(2.5)	(4.0)	(0.0)
State Income Taxes		**1,135.8**	**624.8**	**784.7**	-	**75.2**	**(488.3)**	**139.4**
Operating Income		109,147.2	74,071.0	25,300.8	-	5,623.7	2,725.1	1,426.6
State Income Tax		(1,186.9)	(660.3)	(793.7)	-	(77.8)	484.3	(139.4)
Federal Statutory Adj.		(84,601.4)	(58,651.1)	(15,118.8)	-	(4,217.1)	(6,587.9)	(26.6)
Federal Taxable Income		**23,358.8**	**14,759.6**	**9,388.3**	-	**1,328.8**	**(3,378.5)**	**1,260.6**
Federal Income Tax at 35%	35.00%	8,175.6	5,165.9	3,285.9	-	465.1	(1,182.5)	441.2
Deferred Income Taxes	GP	20,631.3	14,352.1	3,643.8	-	1,023.4	1,605.1	6.8
Tax Refund Amortization	GP	(681.6)	(474.1)	(120.4)	-	(33.8)	(53.0)	(0.2)
Flow Back of Excess Def. Tax	GP	(88.4)	(61.5)	(15.6)	-	(4.4)	(6.9)	(0.0)
Effect of CNIT Def Tax on FIT	GP	17.9	12.4	3.2	-	0.9	1.4	0.0
Federal Income Taxes		**28,054.8**	**18,994.8**	**6,796.9**	-	**1,451.2**	**364.1**	**447.8**
Total Income Tax		**29,190.6**	**19,619.5**	**7,581.6**	-	**1,526.4**	**(124.2)**	**587.2**
Investment Tax Credit	GP	(360.2)	(250.6)	(63.6)	-	(17.9)	(28.0)	(0.1)

Proposed Rates								
Revenues		581,070.4	423,151.1	116,554.0	-	20,600.7	19,023.8	1,740.8
O&M Expense		(368,382.6)	(2[illegible]2,467.6)	(75,240.3)	-	(10,563.7)	(9,817.4)	(293.5)
Depreciation Expense		(54,751.3)	([illegible]8,863.5)	(9,421.4)	-	(2,522.3)	(3,924.2)	(19.9)
Other Taxes		(3,221.1)	([illegible],3[illegible]6.8)	(527.8)	-	(136.7)	(209.2)	(0.5)
Operating Income		**154,715.4**	**10[illegible] 473.1**	**31,364.4**	-	**7,378.0**	**5,073.0**	**1,426.9**
Statutory Adjustments	GP	(53,214.3)	(37,[illegible]18.5)	(9,398.5)	-	(2,639.7)	(4,140.0)	(17.6)
Interest on Debt	RB	(34,320.9)	(23,[illegible]3.5)	(6,238.4)	-	(1,722.9)	(2,676.1)	(9.9)
PA Bonus Depreciation	GP	(7,572.7)	(5,268.0)	(1,337.5)	-	(375.6)	(589.1)	(2.5)
State Taxable Income		**59,607.4**	**43,513.2**	**14,390.0**	-	**2,639.7**	**(2,332.3)**	**1,396.8**
State Income Tax at 9.99%	9.99%	5,954.8	4,347.0	1,437.6	-	263.7	(233.0)	139.5
State Deferred Income Tax	GP	(51.1)	(35.5)	(9.0)	-	(2.5)	(4.0)	(0.0)
State Income Taxes		**5,903.7**	**4,311.4**	**1,428.5**	-	**261.2**	**(237.0)**	**139.5**
Operating Income		154,715.4	109,473.1	31,364.4	-	7,378.0	5,073.0	1,426.9
State Income Tax		(5,954.8)	(4,347.0)	(1,437.6)	-	(263.7)	233.0	(139.5)
Federal Statutory Adj.		(87,535.2)	(60,692.0)	(15,636.9)	-	(4,362.7)	(6,816.1)	(27.5)
Federal Taxable Income		**61,225.4**	**44,434.2**	**14,289.9**	-	**2,751.6**	**(1,510.1)**	**1,259.8**
Federal Income Tax at 35%	35.00%	21,428.9	15,552.0	5,001.5	-	963.1	(528.5)	440.9
Deferred Income Taxes	GP	20,631.3	14,352.1	3,643.8	-	1,023.4	1,605.1	6.8
Tax Refund Amortization	GP	(681.6)	(474.1)	(120.4)	-	(33.8)	(53.0)	(0.2)
Flow Back of Excess Def. Tax	GP	(88.4)	(61.5)	(15.6)	-	(4.4)	(6.9)	(0.0)
Effect of CNIT Def Tax on FIT	GP	17.9	12.4	3.2	-	0.9	1.4	0.0
Federal Income Taxes		**41,308.1**	**29,380.9**	**8,512.5**	-	**1,949.2**	**1,018.0**	**447.5**
Total Income Tax		**47,211.745**	**33,692.3**	**9,941.0**	-	**2,210.3**	**781.1**	**587.0**
Investment Tax Credit	GP	(360.2)	(250.6)	(63.6)	-	(17.9)	(28.0)	(0.1)

ıd/Peak-and-Average COSS

	Demand							Customer						
Total	Total D	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS	Total C	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
80,964,022	80,964,022	33,927,676	15,162,538	-	6,865,950	19,424,858	5,583,000	-						
100.00%	100.00%	41.90%	18.73%		8.48%	23.99%	6.90%	0.00%	0 00%	0 00%		0.00%	0.00%	0.00%
.	191	88	411		14,702	194,249	507,545							
33,488,984	33,488,984	23,280,676	9,128,568	-	864,065	150,675	65,000	-						
100.00%	100.00%	69.517%	27.26%		2.58%	0.45%	0.19%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
	58.6%	31.4%	39.8%		87.4%	99.2%	98.8%							
46,285,029	46,285,029	33,927,676	11,277,612	-	864,065	150,675	65,000	-						
100.00%	100.00%	73.30100%	24.3660%		1.8670%	0.3260%	0.1400%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
190,480	190,480	133,198	51,541	-	4,657	812	272	-						
100.00%	100.00%	69.928%	27.06%		2.44%	0.43%	0.14%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
	$ 5.69	$ 5.72	$ 5.65		$ 5.39	$ 5.39	$ 4.19							
75,381,022	75,381,022	33,927,676	15,162,538		6,865,950	19,424,858	-	-						
100.00%	100.00%	45.00800%	20.1150%		9.1080%	25.7690%	0.0000%	0.00%	0 00%	0.00%		0.00%	0.00%	0.00%
791,995	791,995	458,700	189,733		65,702	77,860	-	-						
100.00%	100.00%	57.91700%	23.9560%		8.2960%	9.8310%	0.0000%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
28.01%	28.01%	20.26%	21.89%		28.63%	68.35%	#DIV/0!							
1.87	1.87	1.19	5.14		140.69	778.60	-							
423,809	-							423,809	386,310	36,921		467	100	11
100.00%	0.000%	0.000%	0.000%		0.000%	0.000%	0.000%	100.000%	91.151%	8.712%		0.110%	0.024%	0.003%
25,782,967	-	-	-		-	-	-	25,782,967	19,259,659	6,218,634		229,488	71,085	4,101
									50	168		491	711	373
100.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	100 000%	74.699%	24 119%		0.890%	0.276%	0.016%
								1.2	1.0	3.4		9.9	14.3	7.5
5,629,652	-	-	-		-	-	-	5,629,652	-	1,381,785		1,880,479	2,367,388	-
									0	37		4,027	23,674	0
100.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	100.00%	0.00%	24.54%		33.40%	42.05%	0 00%
282,023	-	-	-		-	-	-	282,023	259,338	22,106		441	137	-
									671	599		945	1,373	0
100.00%	0.00%	0 00%	0.00%		0.00%	0.00%	0.00%	100.00%	91.95700%	7.8380%	0.0000 6	0.1560%	0.0490%	0.0000%
								1.0	1.0	0.9		1.4	2.0	0.0
116	-							116	-	18		-	88	10
100.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	100.00%	0.00%	15.52%		0.00%	75.86%	8.62%
89,468	-							89,468	65,556	23,912		-	-	-
100.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	100.00%	73.27%	26.73%		0.00%	0.00%	0.00%

ıd/Peak-and-Average COSS

Total	Demand							Customer						
Total	Total D	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS	Total C	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
2,761,797	-							2,761,797	2,504,494	250,777		5,364	1,162	-
100.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	100.00%	90 68%	9.08%		0.19%	0.04%	0.00%
7,675,643	7,675,643	7,060,733	614,910		-	-	-	-						
100.00%	100.00%	91.99%	8.01%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
1,752,694	1,752,694	1,573,774	178,920					-						
100.00%	100.00%	89.79%	10.21%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
1,318,074	1,318,074	954,126	272,928		46,415	41,032	3,573	-	-	-		-	-	-
100.00%	100.00%	72.39%	20.71%		3.52%	3.11%	0.27%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
1	-	-	-		-	-	-	1	-	-		-	-	1
100.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	100.00%	0.00%	0.00%		0.00%	0.00%	100.00%
1	1	1	-		-	-	-	-	-	-		-	-	-
100.00%	100.00%	100.00%	0.00%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
1	-	-	-		-	-	-	-	-	-		-	-	-
0.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	0 00%	0.00%	0.00%		0.00%	0.00%	0.00%
770,383	676,161	387,457	151,137	-	52,857	84,710	-	94,222	86,018	8,097	-	85	22	-
100.00%	87.77%	50.29%	19.62%		6.86%	11.00%	0.00%	12.23%	11.17%	1.05%		0.01%	0.00%	0.00%
1,247,714	1,094,941	627,429	244,744		85,593	137,175	-	152,773	139,294	13,111		137	36	195
100.00%	87.76%	50.29%	19.62%		6.86%	10.99%	0.00%	12.24%	11.16%	1.05%		0.01%	0 00%	0.02%
1,702,741	1,094,941	627,429	244,744		85,593	137,175	-	607,800	557,688	48,773		847	259	233
100.00%	64.30%	36.85%	14.37%		5.03%	8.06%	0.00%	35.70%	32.75%	2.86%		0.05%	0.02%	0.01%
111,891	-	-	-		-	-	-	111,891	86,053	24,662		888	273	15
100.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%	100.00%	76.91%	22.04%		0.79%	0.24%	0.01%
	1,872,017	1,302,068	330,235	-	93,049	146,088	577							
1,872,017	1,139,067	652,714	254,607		89,043	142,703	-	732,951	649,354	75,628		4,006	3,385	577
100.00%	60.85%	34.87%	13.60%		4 76%	7.62%	0.00%	39 15%	34.69%	4.04%		0.21%	0.18%	0.03%
1,945,029	1,185,892	680,536	265,198		92,335	147,815	9	759,137	672,520	78,326		4,149	3,506	636
100.00%	60.97%	34.99%	13.63%		4.75%	7.60%	0.00%	39.03%	34.58%	4.03%		0 21%	0.18%	0.03%
1,325,131	877,045	512,957	197,348		64,696	101,953	91	448,086	401,078	43,518		1,826	1,373	291
100.00%	66.19%	38.71%	14.89%		4.88%	7.69%	0.01%	33.81%	30.27%	3.28%		0.14%	0.10%	0.02%
41,964	24,262	13,903	5,423		1,897	3,040	-	17,703	15,406	1,890		196	206	5

d/Peak-and-Average COSS

	Demand							Customer						
Total	Total D	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS	Total C	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
100.00%	57.81%	33.13%	12.92%		4.52%	7.24%	0.00%	42.19%	36.71%	4.50%		0.47%	0.49%	0.01%
74,547	36,175	20,933	8,142		2,745	4,352	2	38,373	33,917	3,856		294	298	8
100.00%	48.53%	28.08%	10.92%		3.68%	5.84%	0.00%	51.47%	45.50%	5.17%		0.39%	0.40%	0.01%
24,202.82	11,145.84	6,419	2,497		859	1,371	0	13,057	11,379	1,407		132	136	2
100.00%	46.05%	26.52%	10.32%		3.55%	5.66%	0.00%	53.95%	47.02%	5.81%		0.55%	0.56%	0.01%
532,996	532,996	385,825	110,365		18,769	16,592	1,445	-						
100.00%	100.00%	72.39%	20.71%		3.52%	3.11%	0.27%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
39,669	39,669	-	2,863		18,769	16,592	1,445	-						
100.00%	100.00%	0.00%	7.22%		47.31%	41.83%	3.64%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%
46,057	46,057	35,757	6,133	-	1,781	2,387	0							
100.00%	100.00%	77.64%	13.32%		3.87%	5.18%	0.00%							
493,327	493,327	385,825	107,502		-	-	-	-						
100.00%	100.00%	78.21%	21.79%		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%		0.00%	0.00%	0.00%

emand/Peak-and-Average COSS

	Total Distribution		Regulated Pressure Remaining			Regulated Pressure Only			Low Pressure			Transmission		
h	Cost	Unit Cost	Length	Cost	Unit Cost	Length	Cost	Unit Cost	Length	Cost	Unit Cost	Length	Cost	Unit Cost
,727	121,789,892	12.75	266,893	3,404,056	12.75	8,013,766	102,201,159	12.75	1,269,068	16,184,678	12.75			#DIV/0!
,195	9,166,379	2.22	0	157	#DIV/0!	3,224,530	7,145,881	2.22	911,471	2,019,911	2.22	194	430	2.22
,236	10,346	0.24	38,078	9,112	0.24	2,474	831	0.34	1,684	403	0.24	0	0	#DIV/0!
,964	130,966,187	9.54	304,971	3,413,325	11.19	11,240,770	109,347,871	9.73	2,182,223	18,204,992	8.34	194	430	2.22
,525	770,382,773	19.25	5,385,168	160,511,272	29.81	22,157,625	379,849,758	17.14	12,114,210	217,938,408	17.99	353,522	12,083,335	34.18
		49.55%			37.54%			56.76%			46.358%			

	Total D	RS/RDS	SGS/SGDS		SDS/LGSS	LDS/LGSS	MDS/NSS	Total C	RS/RDS	SGS/SGDS		SDS/LGSS	LDS/LGSS	MDS/NSS
								Demand Per Customer						
5	791,995	458,700	189,733	0	65,702	77,860								
0	285,850	224,300	59,495		2,053	2		1.52	1.30	3.74		108.05	2.00	
0	277,730	139,100	71,149		35,828	31,653		2.06	1.13	6.14		219.80	688.11	
5	791,995	458,700	189,733	0	65,702	77,860	0	1.89	1.20	5.16		140.99	794.49	
								Throughput Per Customer						
	0													
06	24,410,606	18,895,850	5,143,484		281,056	90,217		130	110	323		14,792	90,217	
53	27,537,653	11,677,892	5,492,697		2,714,731	7,652,333		204	95	474		16,655	166,355	
56	81,824,556	38,662,408	16,424,024	0	7,243,498	19,494,626	0	196	101	446		15,544	198,925	
9								188,289	172,366	15,903		19	1	
5								134,665	122,867	11,589		163	46	
9								418,439	381,074	36,801	0	466	98	
	12,083	6,998	2,895		1,002	1,188	0							
8	116,906	91,733	24,332		840	1	0	101,033	92,489	8,533		10	1	0
0	164,256	82,267	42,079		21,190	18,720	0	215,594	196,706	18,554		261	74	0
1	100,251	58,063	24,017		8,317	9,856	0	60,260	54,879	5,300		67	14	0
3	393,497	239,061	93,322	0	31,348	29,765	0	376,886	344,073	32,387	0	338	88	0
%	51.078%	31.031%	12.114%	0.000%	4.069%	3.864%	0.000%	48.922%	44.663%	4.204%	0.000%	0.044%	0.011%	0.000%
	12,083	6,998	2,895	0	1,002	1,188	0	0	0	0	0	0	0	0
8	217,938	169,857	45,641	0	2,037	403	0	0	0	0	0	0	0	0
0	379,850	175,665	86,538	0	43,224	74,423	0	0	0	0	0	0	0	0
1	160,511	84,403	35,335	0	13,762	27,011	0	0	0	0	0	0	0	0
3	770,383	436,923	170,409	0	60,026	103,025	0							
%	100.000%	56.715%	22.120%	0.000%	7.792%	13.373%	0.000%							
	12,083	6,998	2,895	0	1,002	1,188	0	0	0	0	0	0	0	0
3	192,680	150,326	40,314	0	1,738	303	0	25,258	23,122	2,133	0	3	0	0
)	325,951	152,315	75,423	0	37,715	60,498	0	53,898	49,176	4,638	0	65	18	0
1	145,446	77,818	32,506	0	12,401	22,722	0	15,065	13,720	1,325	0	17	4	0
3	676,161	387,457	151,137	0	52,857	84,710	0	94,222	86,018	8,097	0	85	22	0
%	87.770%	50.294%	19.618%	0.000%	6.861%	10.996%	0.000%	12.230%	11.166%	1.051%	0.000%	0.011%	0.003%	0.000%

ak-and-Average COSS

	Demand							Customer						
Total	Total D	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS	Total C	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
25,650.5	15,607.5	8,943.5	3,488.6	-	1,220.1	1,955.3	-	10,042.9	8,897.5	1,036.3	-	54.9	46.4	7.909
6,188.9	6,188.9	4,536.5	1,508.0	-	115.5	20.2	8.7	-	-	-	-	-	-	-
-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6,135 0	5,384.6	3,085.5	1,203.6	-	420.9	674.6	-	750.3	685.0	64.5	-	0.7	0.2	-
1.2	-	-	-	-	-	-	-	1.2	-	-	-	-	-	1.198
503.5	441.9	253.2	98.8	-	34.5	55.4	-	61.6	56.2	5.3	-	0.1	0.0	-
4.0	3.5	2.0	0.8	-	0.3	0.4	-	0.5	0 4	0.0	-	0.0	0.0	-
3,330.6	2,92[illegible].2	1,675.1	653.4	-	228.5	366.2	-	40[illegible].3	371.9	35.0	-	0.4	0.1	-
27.2	-	-	-	-	-	-	-	27.2	-	-	-	-	-	27.227
87.7	-	-	-	-	-	-	-	87.7	-	21.5	-	29.3	36.9	-
9,396.0	5,717.2	3,276.1	1,277.9	-	446.9	716.3	-	3,676.8	3,259.2	379.6	-	20.1	17.0	2.897
1,125.9	685 1	392.6	153.1	-	53.6	85.8	-	440.8	390 5	45.5	-	2.4	2.0	0.347
16.5	14.5	8.3	3.2	-	1.1	1.8	-	2.0	1.8	0.2	-	0.0	0 0	-
1,247,518.5	1,094,941.0	627,428.5	244,743.6	-	85,593.5	137,175.3	-	152,577 6	139,293.6	13,111.3	-	136.9	35.7	-
195.3	-	-	-	-	-	-	-	195.3	-	-	-	-	-	195.253
40,284 9	35,357.9	20,260.9	7,903.3	-	2,764.0	4,429.7	-	4,927.0	4,498.1	423.4	-	4.4	1.2	-
1.2	-	-	-	-	-	-	-	1.2	-	-	-	-	-	1.178
454,989.4	-	-	-	-	-	-	-	454,989.4	418,394.6	35,662.1	-	709.8	222.9	-
37.6	-	-	-	-	-	-	-	37.6	-	-	-	-	-	37.630
36,181.3	-	-	-	-	-	-	-	36,181.3	27,027.0	8,726.6	-	322.0	99.9	5.789
23,761.1	-	-	-	-	-	-	-	23,761.1	17,749.3	5,730.9	-	211.5	65.6	3.802
36,486.3	-	-	-	-	-	-	-	36,486.3	27,254.9	8,800.1	-	324.7	100.7	5.838
11,597.2	-	-	-	-	-	-	-	11,597.2	10,516.7	1,053.0	-	22.5	4.9	-
3,864.8	-	-	-	-	-	-	-	3,864.8	3,504.7	350.9	-	7.5	1.6	-
5,504.7	-	-	-	-	-	-	-	5,504.7	-	1,351.1	-	1,838.7	2,314.9	-
299.3	-	-	-	-	-	-	-	299.3	-	-	-	-	-	299.289
1,190.0	-	-	-	-	-	-	-	1,190.0	-	292.1	-	397.5	500.4	-
38.4	-	-	-	-	-	-	-	38.4	-	-	-	-	-	38.438
3,209.1	1,952.7	1,118.9	436.5	-	152.6	244.6	-	1,256.5	1,113.2	129.6	-	6.9	5.8	0.989
1,885,786.7	1,147,421.6	657,501.2	256,474.2	-	89,696.0	143,750.2	-	738,365.1	654,117.3	76,182.8	-	4,035.4	3,409.7	619.875
27,403 5	16,674.2	9,554.7	3,727.1	-	1,303.5	2,089.0	-	10,729.3	9,505.6	1,107.1	-	58.6	49.6	8.449
1,945,029.5	1,185,892.2	680,536.0	265,197.9	-	92,335.0	147,814.6	8.7	759,137.3	672,520.3	78,326.1	-	4,148.9	3,505.7	636.234

eak-and-Average COSS

x.					Demand								Customer		
or	Total	Total D	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS	Total C	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
i		-	-	-	-	-	-	-	-	-	-	-	-	-	-
i		-	-	-	-	-	-	-	-	-	-	-	-	-	-
I		-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
:	8.2	8.2	6.0	2.0	-	0.2	0.0	0.0	-	-	-	-	-	-	-
:	28.5	28.5	20.9	6.9	-	0.5	0.1	0.0	-	-	-	-	-	-	-
:	74.8	74.8	54.8	18.2	-	1.4	0.2	0.1	-	-	-	-	-	-	-
:	12.6	12.6	9.2	3.1	-	0.2	0.0	0.0	-	-	-	-	-	-	-
:	2.3	2.3	1.7	0.6	-	0 0	0.0	0.0	-	-	-	-	-	-	-
:		-	-	-	-	-	-	-	-	-	-	-	-	-	-
:		-	-	-	-	-	-	-	-	-	-	-	-	-	-
.	5.8	5.8	4.2	1.4	-	0.1	0.0	0.0	-	-	-	-	-	-	-
.	5.0	5.0	3.7	1.2	-	0.1	0.0	0.0	-	-	-	-	-	-	-
.	5.0	5.0	3.6	1.2	-	0.1	0.0	0.0	-	-	-	-	-	-	-
	142.2	**142.2**	**104.2**	**34.6**	-	**2.7**	**0.5**	**0.2**	-	-	-	-	-	-	-
D	1,819.6	1,052.0	602.8	235.1	-	82.2	131.8	-	767.6	668.0	81.9	-	8.5	8.9	0.2
?	78.8	69.1	39.6	15.5	-	5.4	8.7	-	9.6	8.8	0 8	-	0.0	0.0	0.0
;	4,603.8	2,960.5	1,696.4	661.7	-	231.4	370.9	-	1,643.4	1,507.9	131.9	-	2.3	0.7	0.6
?	294.9	258.8	148.3	57.9	-	20.2	32.4	-	36.1	32.9	3.1	-	0.0	0.0	0.0
	161.3	-	-	-	-	-	-	-	161.3	-	39.6	-	53.9	67.8	-
?	1,603.8	-	-	-	-	-	-	-	1,603.8	1,233.5	353.5	-	12.7	3.9	0.2
.	2,917.7	-	-	-	-	-	-	-	2,917.7	2,683.1	228.7	-	4.6	1 4	-
D	2,456.9	1,420.4	813.9	317.5	-	111.0	178.0	-	1,036.4	902.0	110.6	-	11.5	12.1	0.3
D		-	-	-	-	-	-	-	-	-	-	-	-	-	-
	13,936.8	*5,760.8*	*3,301.1*	*1,287.7*	-	*450.3*	*721.7*	-	*8,176.0*	*7,036.1*	*950.2*	-	*93.5*	*94.9*	*1.4*
D	35.6	20.6	11.8	4.6	-	1.6	2.6	-	15.0	13.1	1.6	-	0.2	0.2	0.0
!	6.8	6.0	3.4	1.3	-	0.5	0.7	-	0.8	0.8	0.1	-	0.0	0 0	0.0
!	3,533.1	3,100.5	1,776.7	693.0	-	242.4	388.4	-	432.6	394.4	37.1	-	0 4	0.1	0.6
!	312.0	273.8	156.9	61.2	-	21.4	34.3	-	38.2	34.8	3.3	-	0.0	0.0	0.0
	59.2	-	-	-	-	-	-	-	59.2	-	14.5	-	19.8	24.9	-
	1,117.5	-	-	-	-	-	-	-	1,117.5	1,027.6	87 6	-	1.7	0.5	-
	39.6	-	-	-	-	-	-	-	39.6	29.6	9.5	-	0 4	0.1	0.0
D	242.0	139.9	80.2	31.3	-	10.9	17.5	-	102.1	88.9	10.9	-	1.1	1.2	0.0
	5,345.8	*3,540.8*	*2,028.9*	*791.4*	-	*276.8*	*443.6*	-	*1,805.1*	*1,589.1*	*164.7*	-	*23.6*	*27.0*	*0.6*
	19,282.6	**9,301.6**	**5,330.0**	**2,079.1**	-	**727.1**	**1,165.3**	-	**9,981.1**	**8,625.2**	**1,114.8**	-	**[illegible]17.1**	**121.9**	**2.1**
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
	532.4	-	-	-	-	-	-	-	532.4	485.3	46.4	-	[illegible].6	0.1	0.0
	738.1	-	-	-	-	-	-	-	738.1	672.8	64.3	-	[illegible]	0.2	0.0
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-

:ak-and-Average COSS

		Demand							Customer						
c or	Total	Total D	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS	Total C	RS/RDS	SGS/SGDS	-	SDS/LGSS	LDS/LGSS	MDS/NSS
:		-	-	-	-	-	-	-	-	-	-	-	-	-	-
G		-	-	-	-	-	-	-	-	-	-	-	-	-	-
J		-	-	-	-	-	-	-	-	-	-	-	-	-	-
;		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
-		-	-	-	-	-	-	-	-	-	-	-	-	-	-
	1,270.4	-	-	-	-	-	-	-	1,270.4	1,158.0	110.7	-	1.4	0.3	0.0
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
;		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3,507.6	1,702.1	984.9	383.1	-	129.2	204.8	0.1	1,805.5	1,595.8	181.4	-	13.9	14.0	0.4
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
		-	-	-	-	-	-	-	-	-	-	-	-	-	-
	3,507.6	1,702.1	984.9	383.1	-	129.2	204.8	0.1	1,805.5	1,595.8	181.4	-	13.9	14.0	0.4
	24,202.8	11,145.8	6,419.2	2,496.9	-	858.9	1,370.5	0.3	13,057.0	11,379.1	1,406.9	-	132.3	136.2	2.5

73.54%

EXHIBIT IEc-3

REFERENCED INTERROGATORY RESPONSES

OSBA-I-23 (excluding attachments)

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2015-2468056

Data Requests

Office of Small Business Advocate – Set 1

Question No. 1-023:

Reference Statement No. 14, proposed main and service extension policy modification:

a. Please provide the cost or other basis for your selection of 150 feet of main extension per customer and 150 feet of service line.
b. Is it correct that the Company proposes to allow for 150 feet of main extension *and* 150 feet of service line for each new residential customers, regardless of the expected incremental revenues? Please explain your response.
c. Please confirm that Exhibit BEE-2 indicates that the average mains footage per customer on the low pressure system is approximately 64 feet. If you cannot confirm, please explain your response.
d. Please confirm that Exhibit BEE-2 indicates that the average distribution mains footage per customer on the combined low pressure and regulated pressure systems is approximately 95 feet. If you cannot confirm, please explain your response.
e. Please confirm that the depreciated cost included in the Company's revenue requirement is likely to be well below the cost of newly installed mains and services. If you cannot confirm, please explain your response.
f. Please confirm that it is the Company's intention to require non-residential customers to contribute to the revenue shortfall from new residential customers attached under the proposed policy. If you cannot confirm, please identify all of the specific precautions and modifications to cost assignment and recover that the Company intends to make to avoid this outcome.
g. For each new residential service line installed in the past three years, please provide a listing of the length of the service line and the full installed cost of the line, regulator and meter, in MS Excel electronic format.

h. Please provide the Company's current estimate of the average and reasonable range for the installation cost for 150 feet of 2-inch plastic mains.

Response:

a. Please see lines 17-20 of page 7 and lines 1-2 of page 8 of witness Waruszewski's testimony for the basis of 150 feet of main extension per customer. Please see lines 4-7 of page 11 of witness Waruszewski's testimony for the basis of 150 feet of service line extension per customer.
b. The Company is proposing an allowance of up to 150 feet of main extension for all residential applicants. In addition to the main extension allowance, in areas where the Company owns the service line, the Company proposes an allowance of 150 feet of service line.
c. By dividing the total quantity of low pressure mains on Exhibit BEE-2, Page 22, Line 10 by the total number of low pressure customers (which excludes MLDS customers) on Exhibit BEE-2, Page 27, Line 9, the Company does arrive at an average of approximately 64 feet.
d. The Company is unable to confirm that the average distribution mains footage per customer on the combined low pressure and regulated pressure systems is 95 feet. The Company calculates a weighted average of approximately 106 feet. This figure is calculated by dividing the combined footage of the low pressure and regulated pressure systems shown on Exhibit BEE-2, Page 22, Line 10 and Exhibit BEE-2, Page 23, Line 30 (12,114,210 & 22,157,625, respectively) by the combined number of customers (excluding the MLDS customers) served within these two systems, as shown on Exhibit BEE-2, Page 27, Line 9 and Exhibit BEE-2, Page 28, Line 9 (188,289 & 134,665, respectively).
e. The answer to this question is based on the following assumptions: 1) "depreciated cost" represents the net book value of Columbia's mains and services, as of the end of its historic test year (November 30, 2014), divided by the average number of active customers at the end of the historic test year (Exhibit 111, Allocation Factor 6), and 2) "the cost of newly installed mains and services" represents the current cost to install 150 feet of a 2-inch main, plus the associated average cost of a service line.

   As of November 30, 2014, the net book value of Columbia's mains and services was $1,404,281,290 and the average number of active customers was 423,809. By formula, the average cost per active customer was $3,313.

   Further, the installation cost of a main is assumed to be the same amount reported in response "h" below, or $4,350. The average installation cost of a service line on Columbia's books, as of November

30, 2014, is $3,875, which is calculated by dividing the total plant cost of new service lines added during the test year ended November 30, 2014 by the number of new service lines installed during that same period. Again, by formula, the sum of these two amounts is $8,225.

Using these amounts, the depreciated historic investment cost of mains and services, per current active customer, is lower than the current (estimated based on 2014 activity) combined cost of a 150 foot main installation plus the average cost (estimated based on 2014 test year activity) of a service line.

f. Columbia will make no changes to its current process of cost allocation with either the allowances for main extension or service line. Plant added as a result of a customer electing to use these allowances to convert to natural gas will be available to be used by other customer classes

g. Columbia does not track each combination of residential service line, regulator, and meter. Instead, the costs of each of these three types of investment are tracked individually in the Plant Accounting System ("PowerPlant"). Furthermore, the length of customer service lines is not tracked in PowerPlant. Attachment A to this request includes the total cost of plant additions, for each of these three investment types, for each of the past three calendar years (2012 – 2014). Please note that these totals are at the Company level because these investment types are not tracked, in PowerPlant, by customer type.

h. The average cost of 2-inch plastic main varies throughout Columbia's service territory and is influenced by a variety of factors such as geography, housing density, municipal requirements, and other factors. In 2014, the average cost to install one foot of 2-inch plastic main was $29 per foot, so an average cost to install 150 feet would be $4,350.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	**DOCKET NO. R-2015-2468056**
Columbia Gas of Pennsylvania, Inc.	:	

CERTIFICATE OF SERVICE

I certify that I am serving true and correct copies of the foregoing, on behalf of the Office of Small Business Advocate, by e-filing, e-mail, and/or first-class mail (unless otherwise noted) upon the persons addressed below:

The Honorable Mary D. Long
Administrative Law Judge
Pennsylvania Public Utility Commission
Piatt Place, Suite 220
301 5th Avenue
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OSBA Statement No. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2015-2468056
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

Date Served: July 16, 2015

Date Submitted for the Record: ______________________

OSBA Stmt. 2
R-2015-2468056
8-4-15
Harrisburg JB

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. <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 submitted direct testimony and associated exhibits earlier in this proceeding, and my qualifications were detailed therein.

Q. What issues do you address in this rebuttal testimony?

A. This testimony responds to certain cost allocation and revenue allocation issues raised by various intervenor witnesses in this proceeding, including Mr. Jerome D Mierzwa representing the Pennsylvania Office of Consumer Advocate ("OCA"), Mr. Jeremy B. Hubert representing the Commission's Bureau of Investigation and Enforcement ("I&E"), Mr. James L. Crist representing Penn State University ("Penn State"), and Mr. Frank Plank representing the Columbia Industrial Intervenors ("CII").[1]

Q. How is the balance of your testimony organized?

A. Cost allocation and revenue allocation issues are addressed in Sections 2 and 3 respectively.

2. <u>Cost Allocation</u>

Q. What are the issues in dispute among the parties with respect to cost allocation?

A. The parties who take issue with the cost allocation method proposed by the Company are the OCA, I&E, and the OSBA. The issue in dispute involves the sub-functionalization, classification and allocation of distribution mains costs.[2] All three parties accept that transmission mains should be classified as peak-demand related and allocated using a

[1] I touch briefly on the implications of the testimony of Mr. Matthew White on behalf of the Natural Gas Supplier Parties ("NGSs"), but as a matter of clarification and not rebuttal.

[2] The Company proposes to "sub-functionalize" distribution mains into three categories: low pressure mains, regulated pressure mains serving only specific customers, and regulated pressure mains serving all customers. Classification of mains involves segregating mains into demand-related, commodity-related, and/or customer-related categories. Allocation of mains involves assignment of the classified mains costs among the various customer classes.

design day demand allocation factor. And, while I raised certain concerns regarding the Company's allocation methods for non-mains costs, I and the other experts accept the Company's methods for allocating costs other than mains for the purposes of this proceeding.

Regarding distribution mains costs, a summary of the positions of the parties is shown in Table IEc-R1 below. In short, only OCA objects to the Company's proposal to sub-functionalize distribution plant by operating pressure. Both OCA and I&E propose that no distribution mains costs be classified as customer-related, and that all distribution mains costs be allocated using a 50/50 weighted peak-and-average ("P&A") allocation factor. The Company and OSBA recommend using an average of two methods, with Columbia advocating a 50/50 weighting and OSBA advocating a 75/25 weighting.

Table IEc-R1
Distribution Mains Cost Allocation Methods

	Sub-Functionalization of Distribution Mains	Classification of Distribution Mains to Customer-Related	Allocation of Demand-Related Costs
Columbia	By Operating Pressure	Minimum System, Weighted at 50%	50% Design Day; 50% P&A
I&E	By Operating Pressure	No Customer Component	Peak-and-Average
OCA	No Sub-Functionalization	No Customer Component	Peak-and-Average
OSBA	By Operating Pressure	Minimum System, Weighted at 25%	25% Design Day; 75% Peak-and-Average

Q. Regarding the issue of sub-functionalizing distribution mains costs, what is Mr. Mierzwa's rationale for opposing the Company's method?

A. Mr. Mierzwa argues that the Company fails to reflect the vintage of the mains in its sub-functionalization analysis. In particular, Mr. Mierzwa notes that the low pressure system consists disproportionately of steel mains, which are generally older and more depreciated. He therefore rejects the sub-functionalization method, and retains the method in which all mains costs are allocated to all customer classes.

Q. What are your views regarding Mr. Mierzwa's critique of the Company's proposal?

A. I have several observations. First, Mr. Mierzwa does not address the primary conceptual advantage of the sub-functionalization. In the Company's approach, only those customers who take service at low pressure are allocated costs for the low pressure system. Similarly, for the portions of the regulated pressure system that serve only regulated pressure customers, those costs are assigned only to the regulated pressure customers. In contrast, a "global" approach to distribution mains cost functionalization, as advocated by Mr. Mierzwa, essentially allocates all mains costs to all customers. Therefore, the Company's approach is a modest step in the direction of more accurately pairing specific pieces of pipe with the specific customers served. While I would certainly agree that the Company can make much greater progress in specific cost matching, I believe that reverting to a global approach is a step in the wrong direction.

Second, Mr. Mierzwa appears to argue that customers who are served from older, more depreciated mains should be charged less than similarly situated customers taking service from new mains. I respectfully disagree with this "vintaging" approach. My view is that rates for mains are both more efficient and more equitable if they represent the long-run cost of service. I therefore conclude that replacement cost is a better approach to use when a more sophisticated cost allocation approach is adopted. Thus, to the extent that Columbia should modify its approach to reflect cost differences over time, it should use replacement cost in its sub-functionalization rather than average book cost. This would represent another step in the direction of more accurate cost allocation. Moreover, a replacement cost approach is conceptually more consistent with the practices of most utilities (although Columbia is an exception) who utilize minimum system or zero-intercept cost classification methods. In general, standard practice is for the analyst to adjust mains costs for inflation (typically using engineering cost indexes such as the Handy-Whitman indexes), to better reflect the "real" cost of that plant.[3]

Third, even if the Commission determined that it wanted to reflect vintaging in cost allocation, Mr. Mierzwa's recommended approach does not directly address that issue.

[3] As I indicated in my direct testimony, when developing replacement cost, both cost inflation and technological change should ideally be reflected in the analysis.

In Mr. Mierzwa's approach, all mains costs are lumped together and allocated as a whole, with no reflection of vintage at all.

Thus, while I believe that Columbia can and should make more progress in expanding its method to both better match mains and customers, and to better reflect replacement cost, I conclude that Mr. Mierzwa's recommendation is a step in the wrong direction.

Q. Both Mr. Mierzwa and Mr. Hubert object to the Company's "customer-demand" cost allocation method, in which mains costs are "classified" into customer-related and demand-related components, with the demand-related cost portion being allocated on the basis of class design day demand. What is Mr. Hubert's objection?

A. Mr. Hubert argues that "[i]t is not reasonable to allocate distribution mains investment based solely on design day peak demands as in Columbia's Customer-Demand study" because "[t]he basic reason why Columbia invests in its distribution system is to meet the annual demands for gas by customers." (Mr. Mierzwa uses a similar line of reasoning at pages 18 to 19.) Mr. Hubert therefore relies upon the Company's peak-and-average ("P&A") allocated cost of service study ("ACOSS"), with the recognition that the Commission approved the use of the P&A method in a 1994 National Fuel Gas base rates proceeding.

Q. Do you agree with Mr. Hubert's assessment?

A. I respectfully disagree. First, the Company's customer-demand ("CD") method does not allocate mains costs solely on the basis of design day demand. The CD method attempts to recognize that (a) individual mains must be sized to meet the design day demands of all customers downstream of that main, and (b) that the distribution system is extended to interconnect all customers. The CD method therefore allocates mains costs based both on design day demand, to reflect the sizing of the main, and on number of customers, in an effort to reflect the cost causation for the footage of the system. In contrast, the annual throughput has little or no effect on overall cost causation. A pipeline that is sized to meet annual demands will result in many customers being very cold in the winter. While the minimum system classification approach used in the CD ACOSS has significant theoretical problems, the CD method at least relies on credible cost causation factors.

Second, as I indicated in my direct testimony, while the Commission approved a P&A approach in 1994, it has more recently approved a different approach, namely the use of an "average-and-excess" ("A&E") allocation approach, in two separate proceedings.[4] No party has recommended that an A&E approach be used in this proceeding. Nevertheless, I acknowledge that, in approving the A&E approach, the Commission has expressly rejected the use of a customer component for mains cost allocation. As such, the P&A method is generally less inconsistent with Commission precedent for natural gas distribution than is the CD method.

However, as I noted in my direct testimony, the Commission has approved the use of the minimum system method with a customer component in the electric distribution industry, for both primary and secondary voltage systems.[5] Therefore, it is not clear to me that the Commission has established a "hard-and-fast" rule regarding whether or not cost allocation for utility distribution systems should or should not include a customer component of costs.

Q. At pages 10 to 11 of his testimony, Mr. Mierzwa offers an example as to why mains costs are in no way proportional to customer count. 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. Absent some detailed assessment of the physical layout of the system and the actual

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[4] PA PUC et al. v. PPL Gas Utilities Corporation, R-00061398, Order Entered February 8, 2007, page 112 – 114; and 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..

[5] 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.)

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.

Q. Mr. Mierzwa also argues that non-residential customers are ". . . typically located farther apart than Residential customers." Please comment.

A. Mr. Mierzwa may very well be correct, but he offers no specific evidence. As a matter of common sense, I would generally agree 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 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.

Moreover, it is important to keep in mind the implicit assumption about distance in Mr. Mierzwa's P&A method. The P&A method not only assumes that non-residential customers are further apart than residential customers – it assumes that the relative distance is proportional to load. For example, Mr. Mierzwa's P&A allocator implies that the average distance between Medium General Service customers is 133 times greater than that for residential customers.[6] Thus, for example, if a main must be extended 100 feet for a residential customer, the comparable distance for a medium general service customer would need to be more than 2.5 miles to justify the use of the unadjusted P&A approach. Thus, at least conceptually, it is reasonable to assume that there are some economies of scale in mains footage associated with larger customers. While there is no guarantee that the CD method reflects those economies with any precision, it is clear that the P&A method does not reflect them at all.

Q. At pages 12-13 Mr. Mierzwa cites <u>Principles of Public Utility Rates</u>, Bonbright et al., in support of the assertion that there is no customer component to cost. Can you respond?

[6] The 133 factor represents the per-customer P&A allocation factor for Medium General Service customers divided by the per-customer P&A allocation factor for residential customers.

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 analysis that I have seen demonstrates quite a strong correlation between system distance and number of customers, and only a very weak correlation between system distance and loads. As such, the analysis which I have been able to review contradicts the conclusion.[7]

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

[7] 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..

averaging the CD ACOSS with an ACOSS that does not include a customer component. Columbia performs the weighting on a 50/50 basis. I suggest a 75/25 weighting (P&A/CD), to reflect Commission precedent, for the purpose of this proceeding.

Q. At pages 21 to 23, 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 economically 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. However, 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 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. 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. In addition to your technical evaluation, is there a big picture problem with the use of the P&A method?

A. Yes. As it stands, the cost allocation method used for the MDS class is that of direct assignment.[8] However, for the Large General Service class, the traditional P&A approach advocated by Mr. Mierzwa would imply than an increase from $15.8 million to $37.8 million would be required to move rates into line with allocated cost.[9] That would

[8] MDS customers are generally large industrial customers located in reasonably close proximity to interstate pipelines. As such, the specific distribution facilities serving these customers can be identified, and their costs directly assigned to the class.

[9] The increases required for revenue-cost parity for the Large General Service class under the PR cost allocation method are considerably higher.

imply an increase of about 139 percent for all customers within the class (and 182 percent for those customers not currently on flex rates). Similarly, large but less extreme increases would be required under the Company's P&A approach (with the sub-functionalization of mains), at 93 percent total and 121 percent for non-flex rate customers.

If the Commission were seriously planning to impose distribution rate increases of this magnitude over the next few rate cases to meet its legal obligations under *Lloyd*, it is likely that the vast majority of Large General Service customers would attempt to switch to flex rate service or make drastic changes to their operations.[10] In effect, the cost allocation study will have little or no relevance for setting rates for the Large General Service class. *At some point, one must conclude that, if a cost allocation method* produces cost allocation results that cannot be supported by the marketplace, that method is simply not an accurate or useful approach to utility cost allocation.

3. <u>Revenue Allocation</u>

Q. Both Mr. Crist and Mr. Plank opine that the Company's proposed revenue allocation to the Large General Service (Rate LGSS/LDS) class is unreasonable because the Company has failed to recognize that a significant portion of Rate LDS load is subject to negotiated "flex" rates, which are not subject to tariff rate increases. Do these witnesses have a legitimate concern?

A. If the Commission accepts the Company's average approach to cost allocation, they do.[11] However, if the Commission accepts any of the cost allocation methods advocated by OCA, I&E or OSBA, they do not.

[10] Already nearly half the Large General Service load is subject to flex rates, although some of that volume is flexed as a result of the Commission's selective corporate welfare policy of allowing NGDCs to discount rates to customers in geographical areas where service territories overlap.

[11] Note, however, that the example in Mr. Plank's testimony at pages 6-7 regarding the implications of flex rate customers on the overall rate increase substantially overstates reality. In Mr. Plank's example, the rate increase for non-flex customers is double that of the class as a whole. In fact, under Columbia's proposal, the proposed average increase of 15.1 percent for the entire Large General Service class translates into an average increase of 19.7 percent for the non-flex rate customers.

Q. Please explain why you believe these witnesses concerns are justified under the Company's average ACOSS.

A. If the Company's average ACOSS is used, the full tariff rates for the Large General Service class as proposed by Columbia will materially exceed the cost of service. To show this impact, I simulated my version of the Company's average ACOSS, but I included my estimate of the shortfall from flex rates in the revenue for each class. The results of this analysis are summarized in Table IEc-R1 below

Table IEc-R1
Summary of Columbia Average ACOSS Results
Columbia Revenue Allocation – No Flex Rates

	Total	Residential	Small General	Medium General	Large General	MDS
Current Rate of Return	6.3%	5.4%	8.2%	8.1%	8.2%	220.1%
Proposed Rate of Return	8.4%	7.7%	9.8%	10.0%	11.0%	220.2%
Current Subsidy ($mm)	–	(13.5)	7.5	1.9	2.7	1.4
Proposed Subsidy ($mm)	--	(12.2)	5.5	1.6	3.7	1.4

Notes: A negative cross-subsidy value indicates the class is receiving the subsidy.
System average rates of return are higher than those in Columbia's ACOSSs, because flex rate shortfalls are added to revenue amounts.

Source: RDK Workpapers

As shown in Table IEc-R1, if the Commission adopts the Company's average ACOSS methodology, the Company's proposed increase at full tariff revenues for the Large General Service class would result in an increase in the cross subsidy from that class (i.e., rates would move farther away from costs), and it would produce a class average rate of return well in excess of system average. Thus, the Company's proposal implicitly results in non-flex Large General Service customers paying rates well in excess of average allocated cost, based on the Company's ACOSS method.

Q. If the Commission accepts the Company's average ACOSS method, how would you modify your revenue allocation proposal to reflect this issue?

A. In my direct testimony, I recommended that first dollar relief ("FDR") be applied to the Residential and Small General Service rate classes up to the first $6 million in any reduction to the Company's claim, split evenly between those two classes. If the Company's average ACOSS is adopted, Table IEc-R1 shows that the Company's revenue allocation makes relatively little progress toward cost-based rates. To improve the cost-responsiveness of the revenue allocation, I would recommend retaining FDR up to the first $6.0 million, but split in the following proportions:

Small General:	$3.0 million	50%
Medium General	$1.0 million	17%
Large General	$2.0 million	33%

This approach would result in reasonably similar class rates of return for these rate classes, while making material progress toward cost-based rates.

Q. At page 8 of his testimony, Mr. Plank also suggests that, if the Commission approves the Company's proposal for a Choice Administrative Charge ("CAC"), such a charge should be imposed on a per-customer basis. Mr. Crist and Mr. White argue that the CAC should be rejected in its entirety. Should either of these changes have any impact on overall revenue allocated to the various rate classes?

A. No.[12] My recommendations for revenue allocation include the effects of the CAC. Thus, if Mr. Plank's recommendation for developing a per-customer CAC were to be adopted (and had an impact on rates), or if the CAC were to be rejected, the reduction in CAC revenues from the Large General Service class (and all other classes) would need to be offset by higher distribution charges.

Q. Please explain why you believe that none of the other cost allocation proposals in this proceeding would justify the concerns raised by Messrs. Crist and Plank with respect to the Large General Service increase.

[12] Mr. Plank may have misinterpreted the Company's proposal. The Company proposes that the CAC for CHOICE customers be applied on a per-therm basis, but the CAC for regular transportation customers (including all Rate LDS customers) would be applied on a per-customer basis.

A. In my weighted average ACOSS method, the cross-subsidy to the Large General Service class at proposed rates is some $7.1 million. Since that subsidy exceeds my estimated flex rate shortfall from that class (about $5.8 million), my weighted average ACOSS implies that even if all of the Large General Service customers paid full freight, the class would still not produce sufficient revenues to cover costs (at the Company's proposed revenue allocation). Moreover, the cost allocation methods espoused by both I&E and OCA assign higher costs to the Large General Service class than does my approach, meaning that the cost under-recovery for that class at full tariff rates is even larger. Thus, under any of the intervenor ACOSS methods, there is no cost justification for mitigating the Company's proposed increase to the Large General Service class.

Finally, I do not believe that the rate increase proposed by the Company for non-flex Large General Service customers exceeds the normal rules-of-thumb for rate shock. The average increase of 19.7 percent for non-flex Large General Service customers is 1.4 times system average increase of 13.4 percent. The relative increase is therefore below the 1.5 to 2.0 times system average rule often employed for applying the principle of rate gradualism to revenue allocation. As such, I conclude the Company's proposal is not excessive.

Q. Have you reviewed the revenue allocation proposals put forward by the OCA and I&E witnesses?

A. I have. Exhibit IEc-R1 compares the revenue allocation proposals of the Company, the OCA, I&E and OSBA. For consistent comparison purposes, I compare the revenue allocation at a $40.2 million increase, which allows me to reflect the scaleback approach offered by Mr. Hubert and the first dollar relief mechanism that I propose.

As shown in that exhibit, in general, the revenue allocation proposals offered by Mr. Hubert and Mr. Mierzwa are reasonably consistent with the cost allocation methods upon which they rely. While I respectfully disagree with the use of those cost allocation methods, I do not find either revenue allocation proposal to be unreasonable if their cost allocation philosophy is adopted by the Commission.

I note that Mr Mierzwa is most aggressive in proposing increases for the Medium General Service and Large General Service rate classes, with percentage increases for non-flex-rate customers at nearly two times the system average increase. However, even after such large increases, the Large General Service class would only recover about one-half the allocated costs in Mr. Mierzwa's P&A method, and about 40 percent of the allocated costs in the PR method. Thus, even with a large increase, the rates are nowhere near allocated costs. If the Commission adopts a P&A cost allocation methodology, then it will need to impose significant rate increases on those two classes in order to make reasonable progress toward cost-based rates.

Mr. Hubert's proposal is somewhat less aggressive for those two classes, with an average increase on the rough order of 1.5 times the system average. Like Mr. Mierzwa's proposal, however, Mr. Hubert's revenues for the Large General Service rate class come to only about 60 percent of allocated cost, using the method Mr. Hubert advocates. As I noted earlier, adoption of a P&A method for allocating costs in this proceeding will essentially condemn the Large General Service rate class to very large rate increases for the next several rate proceedings, and will increase pressure for flex rates from those customers.

In addition, the revenue allocation proposals advanced by both Mr. Hubert and Mr. Mierzwa would result in revenues from both Residential and Small General Service being above allocated costs (to make up the shortfall from the larger customers). To their credit, the excess recovery from these two classes (based on the cost allocation method each witness prefers) is reasonably comparable for the Residential and the Small General Service classes.

Thus, if the Commission does adopt either of the cost allocation methods advocated by these witnesses, I conclude that each witness' revenue allocation proposal is reasonably consistent with allocated costs and with normal rules for gradualism.

If, however, the Commission rejects reliance solely on P&A methodologies in favor of an average of methods, neither the OCA nor the I&E revenue allocation proposal is consistent with allocated cost. If either the Company's simple average ACOSS is used, or if my recommended weighted average ACOSS is used, a first dollar relief approach should be applied to the Company's proposed revenue allocation. In either case, the Small General Service class should be awarded relief, in order to better move rates into line with allocated cost.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

EXHIBIT IEc-R1

COMPARISON OF REVENUE ALLOCATION RECOMMENDATIONS

EXHIBIT IEc-R1

Summary of Cost Allocation and Revenue Allocation Positions

	Total	Residential	Small General	Medium General	Large General	MDS
Cost Allocation Summaries						
Columbia CD Method						
Rate Base	1,325,130,928	1,045,741,140	200,601,683	40,993,507	37,412,608	381,990
Expenses	426,354,965	329,650,465	80,294,000	10,130,424	5,964,208	315,867
Less COG	-190,479,759	-133,198,002	-51,541,083	-4,656,534	-812,004	-272,136
Income Taxes***	46,850,505	36,972,573	7,092,348	1,449,341	1,322,737	13,505
Return***	107,864,907	85,122,737	16,328,863	3,336,848	3,045,365	31,094
Revenue Requirement	**390,590,618**	**318,547,773**	**52,174,129**	**10,260,079**	**9,520,307**	**88,331**
Columbia/I&E P&A Method						
Rate Base	1,325,130,928	870,122,765	254,286,899	75,034,940	125,304,335	381,990
Expenses	426,354,965	308,327,070	86,812,666	14,263,920	16,635,442	315,867
Less COG	-190,479,759	-133,198,002	-51,541,083	-4,656,534	-812,004	-272,136
Income Taxes***	46,850,505	30,763,519	8,990,409	2,652,889	4,430,182	13,505
Return***	107,864,907	70,827,500	20,698,810	6,107,802	10,199,702	31,094
Revenue Requirement	**390,590,618**	**276,720,088**	**64,960,802**	**18,368,076**	**30,453,322**	**88,331**
Columbia Average Method						
Rate Base	1,325,130,928	957,922,206	227,445,754	58,019,730	81,361,248	381,990
Expenses	426,354,965	318,987,403	83,552,943	12,197,710	11,301,041	315,867
Less COG	-190,479,759	-133,198,002	-51,541,083	-4,656,534	-812,004	-272,136
Income Taxes***	46,850,505	33,867,702	8,041,431	2,051,310	2,876,558	13,505
Return***	107,864,907	77,974,325	18,513,956	4,722,773	6,622,760	31,094
Revenue Requirement	**390,590,618**	**297,631,428**	**58,567,247**	**14,315,258**	**19,988,355**	**88,331**
OSBA Weighted Average Method (after FDR)						
Rate Base	1,325,130,916	914,035,445	240,865,373	66,522,574	103,326,063	381,460
Expenses	426,354,965	313,677,955	85,189,526	13,222,703	13,950,822	313,959
Less COG	-190,479,759	-133,198,002	-51,541,083	-4,656,534	-812,004	-272,136
Income Taxes***	44,360,895	30,598,811	8,063,357	2,226,950	3,459,007	12,770
Return***	104,354,517	71,980,607	18,968,231	5,238,676	8,136,963	30,040
Revenue Requirement	**384,590,619**	**283,059,371**	**60,680,031**	**16,031,795**	**24,734,789**	**84,633**
OCA Alternative P&A Method						
Rate Base	1,325,130,929	832,680,611	253,582,435	82,232,694	156,253,199	381,990
Expenses**	426,354,965	303,868,507	86,694,715	15,114,498	20,361,382	315,863
Less COG	-190,479,759	-133,198,002	-51,541,083	-4,656,534	-812,004	-272,136
Income Taxes***	46,850,505	29,439,738	8,965,503	2,907,368	5,524,391	13,505
Return***	107,864,907	67,779,730	20,641,467	6,693,695	12,718,922	31,094
Revenue Requirement	**390,590,619**	**267,889,973**	**64,760,602**	**20,059,026**	**37,792,691**	**88,326**
OCA PR P&A Method						
Rate Base	1,325,130,927	792,633,489	247,411,220	82,271,364	202,432,064	382,790
Expenses**	426,354,965	298,303,653	85,968,665	15,295,312	26,418,621	368,714
Less COG	-190,479,759	-133,198,002	-51,541,083	-4,656,534	-812,004	-272,136
Income Taxes***	46,850,505	28,023,857	8,747,317	2,908,735	7,157,062	13,534
Return***	107,864,907	64,519,917	20,139,133	6,696,842	16,477,855	31,159
Revenue Requirement	**390,590,619**	**257,649,425**	**63,314,033**	**20,244,355**	**49,241,535**	**141,271**
Current Revenue Summary						
Current Rate Revenues	534,899,150	387,276,078	110,411,494	18,824,003	16,647,057	1,740,519
Less Cost of Gas	-190,479,759	-133,198,002	-51,541,083	-4,656,534	-812,004	-272,136
Distribution Revenues*	**344,419,391**	**254,078,076**	**58,870,411**	**14,167,468**	**15,835,053**	**1,468,383**
Flex Rate Revenues	5,162,702	0	34,785	199,061	3,679,929	1,248,927

EXHIBIT IEc-R1

Summary of Cost Allocation and Revenue Allocation Positions

	Total	Residential	Small General	Medium General	Large General	MDS
CPA Revenue Allocation						
CPA Proposed Revenues	581,070,377	423,115,183	116,568,299	20,608,596	19,037,447	1,740,853
Less Cost of Gas	-190,479,759	-133,198,002	-51,541,083	-4,656,534	-812,004	-272,136
Distribution Revenues*	390,590,618	289,917,181	65,027,216	15,952,062	18,225,443	1,468,717
Revenue Allocation	**46,171,227**	**35,839,106**	**6,156,805**	**1,784,593**	**2,390,390**	**334**
Percent	13.4%	14.1%	10.5%	12.6%	15.1%	0.0%
Percent Non-Flex	13.6%	14.1%	10.5%	12.8%	19.7%	0.2%
CPA R/C Present	100%	97%	114%	112%	90%	1885%
CPA R/C Proposed	*100%*	*97%*	*111%*	*111%*	*91%*	*1663%*
OCA Revenue Allocation	**46,172,485**	**30,676,281**	**8,799,848**	**3,627,689**	**3,068,660**	**7**
Percent	13.4%	12.1%	14.9%	25.6%	19.4%	0.0%
Percent Non-Flex	13.6%	12.1%	15.0%	26.0%	25.2%	0.0%
OCA R/C Present (P&A)	100.00%	107.56%	103.09%	80.10%	47.52%	1885.32%
OCA R/C Proposed (P&A)	100.00%	106.30%	104.49%	88.71%	50.02%	1662.46%
OCA R/C Present (PR)	100.00%	111.83%	105.45%	79.36%	36.47%	1178.75%
OCA R/C Proposed (PR)	100.00%	110.52%	106.88%	87.90%	38.39%	1039.42%
I&E Revenue Allocation	**46,171,227**	**32,339,106**	**8,856,805**	**2,584,593**	**2,390,390**	**334**
Percent	13.4%	12.7%	15.0%	18.2%	15.1%	0.0%
Percent Non-Flex	13.6%	12.7%	15.1%	18.5%	19.7%	0.2%
OCA R/C Present	*100.00%*	*104.13%*	*102.77%*	*87.47%*	*58.97%*	*1885.22%*
OCA R/C Proposed	100.00%	103.50%	104.26%	91.20%	59.85%	1662.75%
OSBA Revenue Allocation	**40,171,227**	**32,839,106**	**3,156,805**	**1,784,593**	**2,390,390**	**334**
Percent	11.7%	12.9%	5.4%	12.6%	15.1%	0.0%
Percent Non-Flex	11.8%	12.9%	5.4%	12.8%	19.7%	0.2%
CPA R/C Present	100.00%	100.23%	108.33%	98.68%	71.49%	1937.36%
CPA R/C Proposed	100.00%	101.36%	102.22%	99.50%	73.68%	1735.39%
Columbia Scaleback	**40,171,227**	**31,181,776**	**5,356,721**	**1,552,684**	**2,079,756**	**290**
Percent	11.7%	12.3%	9.1%	11.0%	13.1%	0.0%
Percent Non-Flex	11.8%	12.3%	9.1%	11.1%	17.1%	0.1%
CPA R/C Present	100%	97%	114%	112%	90%	1885%
CPA R/C Proposed	*100%*	*97%*	*112%*	*112%*	*91%*	*1696%*
OCA Scaleback	**40,172,485**	**26,689,974**	**7,656,330**	**3,156,280**	**2,669,895**	**6**
Percent	11.7%	10.5%	13.0%	22.3%	16.9%	0.0%
Percent Non-Flex	11.8%	10.5%	13.0%	22.6%	22.0%	0.0%
OCA R/C Present (P&A)	100.00%	107.56%	103.09%	80.10%	47.52%	1885.32%
OCA R/C Proposed (P&A)	100.00%	106.30%	104.58%	88.00%	49.90%	1695.67%
OCA R/C Present (PR)	100.00%	111.83%	105.45%	79.36%	36.47%	1178.75%
OCA R/C Proposed (PR)	100.00%	110.51%	106.97%	87.18%	38.29%	1052.33%
I&E Scaleback	**40,171,227**	**27,539,106**	**7,656,805**	**2,584,593**	**2,390,390**	**334**
Percent	11.7%	10.8%	13.0%	18.2%	15.1%	0.0%
Percent Non-Flex	11.8%	10.8%	13.0%	18.5%	19.7%	0.2%
CPA R/C Present	*100%*	*104%*	*103%*	*87%*	*59%*	*1885%*
CPA R/C Proposed	100%	103%	104%	93%	61%	1696%

* Distribution Revenues includes all non-gas-cost tariff revenues plus miscellaneous revenues.

** Includes estimate of impact of increased uncollectibles costs from rate increase.

*** All income tax and return are allocated in proportion to rate base.

OSBA Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2015-2468056
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Surrebuttal Testimony of

ROBERT D. KNECHT

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On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design

Date Served: July 28, 2015

Date Submitted for the Record: ____________________

OSBA Stmt. 3
R-2015-2468056
8-4-15
Harrisburg

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 in my direct testimony.

Q. What issues do you address in this surrebuttal testimony?

A. This testimony responds to certain cost allocation, revenue allocation, and rate design issues raised in the rebuttal testimony of Columbia Gas of Pennsylvania Inc. ("Columbia" or "the Company") witnesses Mr. Brian E. Elliott and Mr. Mark Balmert, as well as the rebuttal testimony of various intervenor witnesses in this proceeding, including Mr. Jerome D Mierzwa representing the Pennsylvania Office of Consumer Advocate ("OCA"), Mr. Jeremy B. Hubert representing the Commission's Bureau of Investigation and Enforcement ("I&E"), and Mr. James L. Crist representing Penn State University ("Penn State").

Q. Mr. Elliott indicates that he agrees with your direct testimony that the customer component of mains costs in the Customer-Demand ("CD") allocated cost of service study ("ACOSS") should be the same value per customer. Does this address the concern you raised in your direct testimony regarding the allocation of customer costs?

A. It is useful that Mr. Elliott confirms his agreement with my direct testimony that the customer component of mains cost is the same per customer, for each type of main allocated in the CD ACOSS. However, Mr. Elliott appears to have misinterpreted by direct testimony. My concern was not related to the mechanics of the *allocation* of mains costs in the ACOSS – in that respect, I agree the Company has applied the correct arithmetic for allocation. My concern was that the Company did not follow that same approach in calculating the customer-related component of costs for the purposes of developing a monthly customer charge.

To demonstrate this difference, I prepared Table IEc-S1 below. It compares how the Company allocates customer-related mains costs when developing its mains cost allocation factor with how the Company allocates customer-related mains costs for deriving the cost basis for the monthly customer charge (or "system charge," as Columbia denotes it).

The upper portion of this table shows how the customer-related components of mains gross plant costs are allocated for deriving the overall ACOSS mains allocation factor, split between transmission, low pressure mains, regulated pressure only mains, and remaining regulated pressure mains. To develop its mains allocation factor, the Company relies on historical mains costs, totaling some $770.3 million. Of that amount, $376.9 million is classified as customer-related in the CD ACOSS. As shown in Table IEc-S1, within each component of costs, the *allocated* customer-related cost is the same per customer, at $0 per customer for transmission, $537 per customer for low-pressure mains, $1,601 for regulated pressure-only mains, and $144 for remaining regulated pressure mains.[1] When totaled across the four categories, the results shown similar per-customer costs, although the Residential class has the highest value because it has the largest proportion of customers served at low pressure, and therefore attracts somewhat higher customer costs than classes where more customers are served at regulated pressure. Overall, in the CD ACOSS method, the Residential class is responsible for 91.3 percent of customer-related mains costs, and the Small General Service class is responsible for 8.6 percent. All of these calculations are arithmetically correct.

However, if we look at Columbia's calculation of the cost basis for the customer charge in the lower part of Table IEc-S1, we see a much different allocation. Note first that the overall costs of mains is somewhat higher ($1,153 million total, compared to $770.3 million total used in developing the mains allocation factor) than that used in the allocation factor development. The overall higher cost is due primarily to the fact that it is based on fully forecast future test year ("FFTY") revenue requirement, whereas the

[1] Regulated pressure only mains refer to a subset of mains operating at medium pressure which serve only an identified subset of customers, and are allocated only to those customers. The remaining regulated pressure mains provide service to customers taking service at both regulated pressure and low pressure.

development of the allocator is based on historical period plant costs.[2] More importantly, however, is the difference in allocation methods. Here, in the cost calculation for the monthly customer charge, the Company reports that the customer-related cost for Small General Service is more than twice that for the Residential class ($2,369 versus $1,061), whereas for cost allocation the customer-related costs for the two classes are similar ($880 versus $903). Similarly, on a percentage basis, the monthly customer charge calculation shows the Small General Service class being assigned 16.3 percent of the customer-related mains costs, rather than the 8.6 percent used in the actual allocation of costs. This results because the Company incorrectly uses an average mains allocation factor, which includes both demand-related and customer-related components, to allocate costs which are strictly customer-related.

Table IEc-S1

Comparison of Columbia Gas Customer-Related Mains Cost Allocation

	Total Cost	Customer Cost	Residential	Small General	Medium General	Large General
Columbia Mains Allocator Development (Exhibit BEE-2)						
Transmission	12,083,335	0	0	0	0	0
Customers		418,439	381,074	36,801	466	98
Cost per Customer		$0	$0	$0	$0	$0
Low Pressure	217,938,408	101,031,887	92,487,943	8,533,213	10,195	537
Customers		188,289	172,366	15,903	19	1
Cost per Customer		$537	$537	$537	$537	$537
Regulated Pressure Only	379,849,758	215,595,126	196,706,838	18,553,684	260,959	73,645
Customers		134,665	122,867	11,589	163	46
Cost per Customer		$1,601	$1,601	$1,601	$1,601	$1,601
Regulated Pressure Remaining	160,511,272	60,260,747	54,879,693	5,299,830	67,11[illegible]	14,113
Customers		418,439	381,074	36,801	466	98
Cost per Customer		$144	$144	$144	$144	$144
Total Allocated Mains Costs	770,382,773	376,887,760	344,074,474	32,386,728	338,264	88,295
Cost per Customer		901	903	880	726	901
Percent		100.0%	91.3%	8.6%	0.1%	0.0%
Columbia Customer Cost Calculation (CD ACOSS page 15)						
Mains Customer Cost	1,152,690,445	534,367,538	404,484,164	87,198,095	21,978,537	20,706,742
Cost per Customer		1,277	1,061	2,369	47,164	211,293
Percent		100.0%	75.7%	16.3%	4.1%	3.9%

[2] The Company's system charge calculations for mains plant are shown in Exhibit 111 Schedule 1 Page 15 and in the electronic ACOSS at the tab labeled "Syst Chg Pgs 15 & 16."

Q. What, then, do you conclude with respect to the Company's derivation of customer-related costs to be used for the calculation of the monthly customer charge?

A. For the reasons detailed in my direct testimony, I conclude that all customer-related costs should be considered in calculating the cost basis for non-residential monthly customer charges. To the extent that the Commission relies on a cost allocation method that reflects a weighting of different ACOSS methods, the same weighting should be applied to the customer cost basis. For example, if the Commission accepts the 50/50 weighting of the CD and P&A ACOSS methods recommended by the Company, it would similarly weight the customer charge cost basis from the two methods equally.

However, for deriving the cost basis for the non-residential monthly customer charge in the CD ACOSS, the Company should correct its allocation of mains customer costs to be consistent with the cost allocation method specified in Mr. Elliott's rebuttal testimony.[3]

Q. Turning to the issue of revenue allocation, in your direct testimony you proposed to apply first dollar relief ("FDR") to the Residential and Small General Service classes, based on your weighted average ACOSS approach. In your rebuttal, you offered an alternative FDR approach in the event the Company's simple average ACOSS approach is adopted. Does the Company agree with your proposal?

A. Apparently not. Mr. Balmert indicates that it is the Company's preference to apply a proportional scaleback approach. However, Mr. Balmert offers no rationale for his proposal. In addition, Mr. Balmert does not rebut the evidence that the Company's proposed progress toward cost-based rates is minimal, nor does he rebut the evidence that the proportional scaleback method reduces progress toward cost-based rates. It is therefore difficult to respond to the Company's unsupported statement of preference, particularly when alternative approaches presented in this proceedingare more consistent with the Commonwealth Court's decision in *Lloyd.*

Q. Please comment on the rebuttal testimony submitted by Mr. Mierzwa and Mr. Crist regarding revenue allocation.

[3] Columbia should also correct similar errors in its calculation of the cost basis for the monthly customer charge involving general plant (Accounts 389-398) and customer-related A&G (Accounts 920-931) where the Company also incorrectly uses mixed customer/demand allocation factors to allocate customer-related costs.

A. Mr. Crist makes it clear that he supports the use of a simple average of the two Columbia ACOSSs. As I indicated in my rebuttal testimony, if that approach is adopted by the Commission, I agree with Mr. Crist that the Company's proposed increase for the Large General Service class should be adjusted downward, and I recommended an alternative FDR approach for doing so.[4]

Mr. Mierzwa indicates that he and I support different cost allocation methods which give rise to our different revenue allocation proposals. I agree with that assessment. While I disagree with Mr. Mierzwa's cost allocation methodology, I agree that his revenue allocation proposal is consistent with the ACOSS method he supports. Moreover, given the huge revenue shortfall from the Large General Service class in Mr. Mierzwa's ACOSS, I conclude that Mr. Mierzwa's very aggressive rate increase proposal for that class would be justified (if the Commission were to adopt his ACOSS) in light of the Commonwealth Court's decision in *Lloyd*.

Q. In his rebuttal testimony, I&E witness Mr. Hubert's rebuttal of the testimony of Mr. Plank and Mr. Crist appears to conclude that any shortfall in revenue from flex rate customers in the Large General Service rate class should be recovered from other customers in that class, except as constrained by gradualism. Do you agree?

A. As a general rule, I do not. However, my concern is largely academic, as both Mr. Hubert and I accept the Company's proposed rate increase for the Large General Service class.

Nevertheless, as a matter of principle, retaining customers who would otherwise be lost to bypass or alternative fuel provides a benefit to all customers on the system, not only those in that class, as long as the revenues exceed the incremental cost of providing service. Thus, it is reasonable that all customers contribute to the shortfall from flex rate customers. I would also observe that Mr. Hubert did not express concern about using the rate revenues from flex rate MDS customers, which exceed allocated costs, to offset the revenue requirements of the other rate classes.

[4] See OSBA Statement No. 2 at page 13.

In addition, requiring non-flex rate customers in the class to make up the entire shortfall presents a practical problem, in that the rates will require huge increases, particularly under Mr. Hubert's ACOSS. Using Mr. Hubert's P&A ACOSS method, the fully allocated costs for the Large General Service class are about $30.5 million. Even with the Company's proposed increase, distribution revenues from that class will be $15.8 million, of which $12.2 million are provided by non-flex-rate customers. If these customers are required to make up the shortfall from the flex rate customers, Columbia will need to impose a 150 percent rate increase in the next few rate cases, above and beyond whatever system average rate increase it requires.

Q. Can you respond to Mr. Hubert's point that some of the shortfall from flex rate customers in the Large General Service class relates to "gas-on-gas competition?"

A. Mr. Hubert's point is well-taken, and I certainly agree that it is long overdue for the Commission to abandon a policy which involves undue and inequitable price discrimination.[5] However, the issue of ending "gas-on-gas competition" supports the principle of setting full tariff rates based on allocated costs. Several of the participants in the Commission's generic proceeding suggested that customers in overlapping service territories be permitted to take service at regular tariff rates from any of the relevant NGDCs. If the Commission adopts that policy, it is particularly important that the regular tariff rates be set as close to allocated cost as possible (subject to gradualism constraints). If full tariff rates are set well above allocated costs, as Mr. Hubert's philosophy would require, customers who can choose among NGDCs will not be choosing among cost-based rate options.

Q. Regarding non-residential rate design, Company witness Mr. Balmert indicates that he agrees with your direct testimony that rate design should follow cost allocation, and that "all of the Company's fixed costs should eventually be recovered through the customer charge because only then will revenue recovery match cost causation and intra-class subsidies can be mitigated." Do you agree?

---

[5] As I testified at Docket No. P-2011-2277868, the policy of "gas-on-gas competition" is not competition at all, but simply a means to subsidize the rates for customers who are fortunate enough to be located in overlapping service territories at the expense of customers who are not so fortunately situated.

A. Not quite. My major concern regarding Mr. Balmert's statement relates to his reference to "fixed" costs. In the ACOSS, distribution costs are classified as either demand-related or customer-related. The term "fixed" costs is often used to encompass all distribution costs, since neither customer-related nor demand-related costs vary with throughput. In contrast, it is my view that the customer charge should reflect costs that are classified as customer-related in the ACOSS. Demand-related costs are best recovered in a demand charge, or where that is infeasible, a commodity charge.

In addition, for heterogeneous classes like small and medium general service, it is important to recognize that some customer-related costs do, in fact, vary with the size of the customer. For example, meters costs are more expensive for larger customers in the class than for smaller customers. For those customer-related cost items, the monthly customer charge should be based not on the cost of the average meter, but rather on the cost of the smallest size meters used in the class. Otherwise, the customer charge will require small customers to subsidize larger customers.

However, if the Company's simple average ACOSS is adopted by the Commission, I would agree with Mr. Balmert that the Company's proposed customer charges are reasonably consistent with allocated customer costs at the Company's full revenue requirement. These increases should be scaled back if the Company's overall cost claim is reduced.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

VERIFICATION

REFERENCE: OSBA Statement No. 1 (Direct Testimony)
OSBA Statement No. 2 (Rebuttal Testimony)
OSBA Statement No. 3 (Surrebuttal Testimony)

COLUMBIA GAS OF PENNSYLVANIA, INC.
Docket No. R-2015-2468056

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: August 3, 2015

(Signature)