OSBA Statement No. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket Nos. R-2012-2321748
	:	M-2012-2323645
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 of Equity Capital
Cost Allocation
Revenue Allocation
Gas Procument Charge Unbundling
Rate Design

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Office of Small Business Advocate

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:		
	:		
v.	:	**DOCKET NO.**	**R-2012-2321748**
	:		**M-2012-2323645**
Columbia Gas of Pennsylvania, Inc.	:		

AFFIDAVIT OF ROBERT D. KNECHT

I, Robert D. Knecht, being duly sworn according to law, depose and say that I am employed as a consultant by the Pennsylvania Office of Small Business Advocate, having qualifications as set forth in Exhibit IEc-1 to my Direct Testimony at OSBA Statement No. 1 and have been authorized to make this affidavit on its behalf, and that the facts set forth in my Direct Testimony (OSBA Statement No. 1), my Rebuttal Testimony (OSBA Statement No. 2) and my Surrebuttal Testimony (OSBA Statement No. 3) and accompanying Exhibits are true and correct to the best of my knowledge, information, and belief and expect to be able to prove the same at any hearing hereof.

Robert D. Knecht

Sworn and subscribed before me
this 11 day of February 2013.

Signature of official administering oath

My Commission Expires: 1/16/15

ELIZABETH ... NOTARY PUBLIC COMMONWEALTH OF MASSACHUSETTS

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COMMONWEALTH OF PENNSYLVANIA
OFFICE OF SMALL BUSINESS ADVOCATE

January 4, 2013

E-MAIL AND FIRST-CLASS MAIL

Hon. Mark A. Hoyer
Administrative Law Judge
Pa. Public Utility Commission
301 Fifth Avenue - #220
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Hon. Jeffrey Watson
Administrative Law Judge
Pa. Public Utility Commission
301 Fifth Avenue - #220
Pittsburgh, PA 15222

**Re: Pennsylvania Public Utility Commission, *et al.* v. Columbia Gas of Pennsylvania, Inc.
Docket Nos. R-2012-2321748 and M-2012-2323645**

Dear Judge Hoyer and Judge Watson:

Enclosed are two copies of the Direct Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1, on behalf of the Office of Small Business Advocate.

As evidenced by the enclosed certificate of service, all parties have been served as indicated.

Sincerely,

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

Enclosures

cc: Parties of Record
Robert D. Knecht

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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	**Docket Nos. R-2012-2321748**
Columbia Gas of Pennsylvania, Inc.	:	**M-2012-2323645**

CERTIFICATE OF SERVICE

I certify that I am serving two copies of the Direct Testimony and Exhibits of Robert D. Knecht, labeled OSBA Statement No. 1, on behalf of the Office of Small Business Advocate, by e-mail and first-class mail (unless otherwise noted) upon the persons addressed below:

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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), and 2011 (Docket No. R-2010-2215623). I have also submitted testimony in a variety of Section 1307(f) and other proceedings involving the Company over the past decade.

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, although this testimony addresses certain other issues. Nevertheless, my analysis 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. Columbia's proposed return on equity ("RoE") of 11.25 percent is excessive when compared to third-party industry equity cost estimates, the allowed returns in other jurisdictions, and recent Pennsylvania Commission precedent.

2. Columbia has submitted two cost of service study ("COSS") methodologies that allocate the Company's revenue requirement among the various rate classes. Both of these COSSs incorporate a substantial change in cost allocation methodology relative to the Company's last three base rates proceedings. This change has the effect of materially increasing costs assigned to smaller customers. While this proposed modification to the COSS may eventually have advantages over the existing methodology, the methodology filed in this proceeding is unduly biased against smaller customers and should be rejected pending further refinement.

3. The issue most often debated for natural gas distribution company ("NGDC") COSSs is that of the *classification* and *allocation* of distribution mains costs. Commission precedent supports a 100 percent demand classification method combined with an average-and-excess ("A&E") demand allocation method. While I respectfully disagree that this methodology reasonably reflects cost causation, I have developed an "IEc A&E COSS" in this testimony at the request of OSBA counsel. I have also developed an "IEc ZI COSS" based on a mains cost allocation methodology that is more consistent with cost causation.

4. In addition to modifying mains cost allocation, my COSSs reflect a variety of other less critical changes to the Company's methodology. I also highlight problems associated with the Company's averaging method for certain key cost items, notably meters and services costs.

5. I offer two alternative revenue allocation proposals based on the two IEc COSS methods. Despite the use of very different costing philosophies and a wide variety of changes to the cost studies, my recommendations for revenue allocation to the small general service classes are generally consistent with those presented by the Company. For the other classes, however, the differences are somewhat larger.

6. The Company's proposed unbundled gas purchase charge ("GPC") should be modified to include a provision for information systems costs and to include storage gas working capital costs. To the extent that Choice natural gas suppliers ("NGSs") choose to continue to rely on the Company for financing gas in storage, they also should be charged for that service.

7. The Company's proposed adoption of a "Pass-through" charge is a well-intentioned effort to reduce customer confusion associated with a wide array of tariff charges and credits. The Company should evaluate whether customer confusion can be reduced and open competition enhanced by billing NGSs

directly for load balancing services, rather than imposing different Pass-through charges on shopping and non-shopping customers..

8. The Company's proposed increase to the customer charge for smaller customers in rate classes SGS, SCD, and SGDS is not consistent with the COSSs developed in this testimony. The rate increases assigned to those classes should be recovered from the customer charge for larger customers and the volumetric charge.

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 and now 2012. 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	--

Columbia's relatively large proposed increase in this proceeding is due in part to its use of 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 last base rates case.

Q. How is the balance of your testimony organized?

A. This testimony is organized as follows:

- Section 2 presents a "top-down" review of the Company's proposed cost of equity capital.

- Section 3 provides a brief overview of Columbia's rate classes, to provide background to the cost allocation, revenue allocation and rate design issues.
- Section 4 addresses my analysis of cost causation, Columbia's COSSs and Commission precedent.
- Section 5 addresses revenue allocation issues.
- Section 6 addresses the rate design issues, including the GPC, the Pass-through charge, and the customer charge for small business customers.

2. Cost of Equity Capital

2.1 Background

Q. Please summarize Columbia's equity cost of capital claim in this proceeding.

A. Columbia asserts that its cost of equity capital is 11.25 percent per annum, based on a discounted cash flow ("DCF") analysis (10.55 percent), a risk premium ("RP") method (11.01 percent), a capital asset pricing model ("CAPM") method (11.13 percent) and a Comparable Earnings ("CE") method (12.70 percent). Columbia's analysis is presented by Mr. Paul R. Moul in Columbia Statement No. 10 and associated exhibits. Mr. Moul's estimate of Columbia's cost of equity capital is lower than that which he presented in the Company's 2011 and 2010 base rates proceeding, wherein he recommended equity returns of 11.60 percent and 11.70 percent respectively.

Q. Have you prepared a full analysis of the cost of equity capital for Columbia using the traditional methods such as those presented in Mr. Moul's testimony?

A. No, I have not. Such an effort is beyond the scope of this testimony. The OSBA requested that I present industry information that the Commission may consider to be relevant when it makes its evaluation of the Company's claim. This information includes:

- An independent assessment of the cost of equity capital for the natural gas distribution industry prepared by Morningstar, Inc. ("Morningstar") using a variety of standard techniques;

- A review of recent regulatory commission awards for utility equity returns; and
- A comparison of Columbia's RoE proposal with the most recent Pennsylvania Public Utility Commission NGDC RoE award in a fully-litigated proceeding.

In effect, I present a "top-down" evaluation of the Company's claimed RoE.

2.2 Morningstar Equity Cost Analysis

Q. Please describe the Morningstar equity cost analysis you are presenting.

A. For many years, Ibbotson Associates, now a subsidiary of Morningstar, has published a Cost of Capital Yearbook. This yearbook, among other things, estimates the cost of equity capital for thousands of firms, and reports the results in aggregate for several hundred industries. Industries are segregated by two, three and four digit Standard Industrial Classification ("SIC") code, one of which is SIC 4924, Natural Gas Distribution. Morningstar uses a variety of different techniques to estimate the cost of equity capital, and applies each of these techniques to each industry.

The techniques used by Morningstar include the single-stage DCF method and CAPM methods used by Mr. Moul. In addition, Morningstar uses a three-stage DCF method and the 3-Factor Fama-French model.

In my view, the Morningstar analysis provides a useful benchmark for Commission consideration. Morningstar, like the predecessor firm Ibbotson Associates, is a highly respected firm with extensive experience in cost of capital analyses that are widely cited in the industry.[1] In addition, Morningstar represents neither utility nor ratepayer, and therefore has no conflict of interest.

Q. Mr. Moul uses the single-stage DCF method. In contrast, Morningstar uses both the single-stage and the three-stage methods. What is the three-stage DCF method?

A. The three-stage DCF method is conceptually similar to the single-stage DCF method, in that it is based on the principle that the value of a firm's equity is equal to the net present

[1] For example, see Mr. Moul's testimony at Appendix H, page H-4, wherein Mr. Moul relies on the Ibbotson Associates' analysis of long-term historical market returns on equity.

value of expected future after-tax equity cash flows, discounted at the cost of equity capital. By examining the current cash flows, the market expectations for future cash flows (from market analysts) and the current value of the firm's equity, the implied cost of equity capital can be derived. In the three-stage DCF model, the future period for which growth estimates are obtained is split into three components: 0 to 5 years, 6 to 10 years, and over 10 years. In Morningstar's implementation of this method, cash flow growth rate estimates are used for the first two periods (based on analysts' estimates) and earnings growth is used for the third period. Morningstar uses analysts' estimates for growth rates in each period from Institutional Brokers Estimate System ("I/B/E/S"). Because the three-stage DCF is a multiple period approach, it is arithmetically more complicated to calculate the cost of equity capital under the three-stage DCF approach than under the single-stage DCF approach. That is, the cost of capital cannot easily be expressed in the "dividend yield plus growth rate" formulation. Nevertheless, it is based on the same theoretical model of the cost of equity as is the DCF model, and is a standard method.

The more complex three-stage DCF approach is generally more useful for firms in high growth industries, where expected future growth rates are different for the three different periods. For relatively mature industries like gas distribution, the additional complexity of this model is less necessary, and produces results that are similar to the single-stage DCF approach. I nevertheless include the results of this model for completeness.

Q. What is the 3-Factor Fama-French model?

A. The 3-Factor Fama-French ("3FFF") model is an equity costing method that is designed to address some of the perceived failings of the CAPM model. In particular, the theory underlying the 3FFF is that the cost of equity capital is based on the correlation of the returns of a particular stock with three factors. One of those factors is the excess return of the market over the risk-free rate (the "market premium"), just as in the CAPM approach. The other two factors are (a) the difference between the returns on small stocks and large stocks and (b) the difference between the returns on stocks with high book-to-market ratios and low book-to-market ratios. In essence, the 3FFF is designed to address the empirical observation that CAPM tends to underestimate the returns on small stocks and stocks with high book-to-market ratios.

Q. What does the Morningstar analysis imply for the equity cost of capital for the natural gas distribution industry?

A. Figure IEc-1 below shows the median equity cost of capital from each of the four methods reported by Morningstar for SIC 4924.[2] Note that, for the CAPM method, I report the median CAPM for the industry plus the size premium for a mid-cap company, based on Morningstar's 2012 size premium (114 basis points).[3]

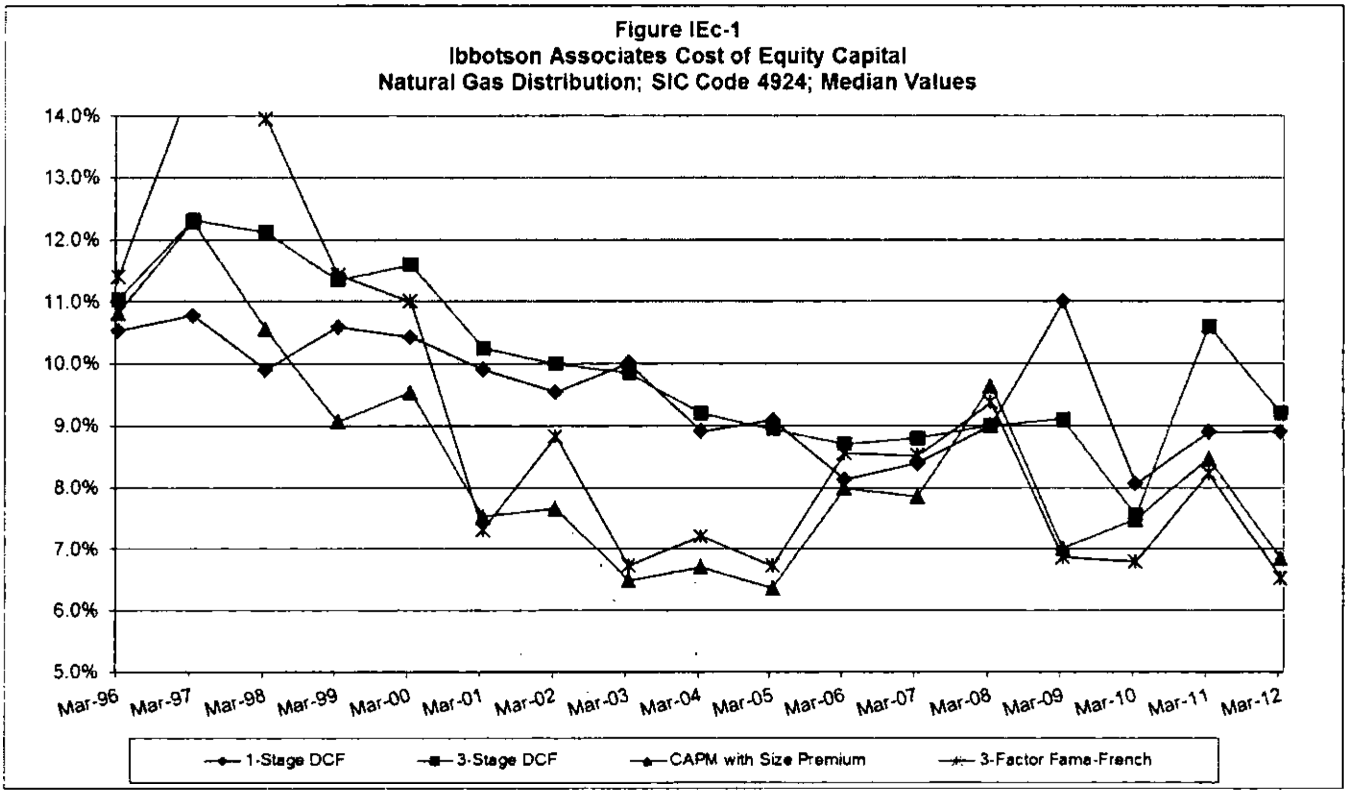

Figure IEc-1 demonstrates the following:

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[2] The source data for this figure are available from the IEc workpapers, which are identified in Exhibit IEc-2. To avoid burdening this (already voluminous) document with extensive workpaper printouts, the OSBA will provide the IEc workpapers in MS Excel electronic format to any active party upon request.

[3] In so doing, I am being conservative. Columbia's parent company, Nisource, Inc., has current equity market capitalization of over $7 billion, above the upper end of Morningstar's $1.6 to $6.9 billion range. If Nisource is considered a large cap firm, the implied CAPM cost of equity capital would be more than 100 basis points lower than that shown in Figure IEc-1.

- DCF cost of capital estimates, both single-stage and three-stage, indicate that the natural gas distribution industry cost of equity capital declined steadily from the late 1990s to the late 2000s, and have been relatively flat (albeit volatile).since that time. From 1999 to 2010, the trend decline in the cost of equity capital as measured using DCF methods has been some 200 to 300 basis points. While allowed RoEs may have modestly declined over the past decade, they have not declined by that amount. In short, regulators are lagging the trends in equity capital costs measured by Morningstar.

- Only two Morningstar cost of equity capital estimates for the natural gas distribution industry have exceeded 10 percent since 2003. No Morningstar cost of equity capital estimate for the natural gas distribution industry has been at or above the 11.25 percent value represented by Mr. Moul since 2000.

- The CAPM and 3FFF methods produced relatively low cost of equity capital estimates in the 2001 to 2005 period, due to a steep drop in beta as estimated by Morningstar during that period.[4] These methods produced similarly low estimates in 2010 and 2012.

2.3 RoE Awards by Regulators

Q. What RoE awards have other utility regulators made in the recent past?

A. Table IEc-2 below presents a summary of the 2008, 2010, 2011 and 2012 Public Utilities Fortnightly reviews of utility commission RoE awards for the previous year for both electric and gas utilities.[5]

[4] "Beta" is a measure of the riskiness of a particular investment option, reflecting the level of correlation between expected returns on the investment and expected returns on the market portfolio of risky investments.

[5] Details are available in my workpapers.

Table IEc-2 Summary of Average US Regulatory RoE Awards			
	Gas Average	**Electric Average**	**State Average**
November 2008	10.44%	10.48%	10.50%
November 2010	10.26%	10.43%	10.28%
November 2011	9.98%	10.10%	10.19%
November 2012	9.92%	10.22%	10.10%
Sources: Public Utilities Fortnightly, various editions; IEc workpapers.			

As shown in Table IEc-2, regulatory RoE awards have been steadily declining over the past five years, particularly for both gas utilities. Moreover, average RoE awards are well below the 11.25 percent value proposed by the Company in this proceeding.

2.5 Pennsylvania Precedent

Q. How does Pennsylvania Commission precedent compare to the results of allowed RoEs from other jurisdictions?

A. I am informed by OSBA counsel that the last fully litigated case in which the Commission set an NGDC RoE involved PPL Gas Utilities, Inc. ("PPL Gas"), now UGI Central Penn Gas. The Commission decided that case on February 8, 2007, and awarded a 10.40 percent RoE. In addition, the Commission has recently awarded PPL Electric a cost-based RoE of 10.28 percent on its distribution rate base (plus a 12 basis point kicker for management effectiveness). The earlier NGDC RoE awards are similar in magnitude to the average award from all other jurisdictions shown in Table IEc-2 for the 2007-2008 period, but do not reflect the subsequent decline in regulatory awards or the decline in capital costs since that time. I should note also that none of these decisions involved a utility with a rate decoupling mechanism such as those proposed by Columbia for the residential class in this proceeding. All other factors being equal, if a rate decoupling mechanism is adopted, Columbia's equity return risk will be lower than other Pennsylvania regulated utilities.

Q. How have market equity capital costs changed since early 2007?

A. Both the CAPM and the risk premium models for evaluating the cost of equity capital rely in part on the level of interest rates, both risk-free rates and corporate borrowing rates. Since February 2007, interest rates have declined substantially:

- In February 2007, the three-month Treasury-bill rate stood at 5.03 percent; in December 2012, it was 0.09 percent.
- In February 2007, the 10-year yield on Treasury bonds was 4.72 percent; in December 2012, it was 1.65 percent.
- In February 2007, the bank prime rate was 8.25 percent; in December 2012, it was 3.25 percent.

In effect, the cost of borrowing has declined markedly since the Commission's 2007 RoE award. Moreover, as shown in Table IEc-2, the average award by other regulatory Commissions has not increased, and has actually declined slightly since the 2007 to 2008 time frame. It is therefore reasonable to conclude that the cost of equity capital for NGDCs has certainly not increased since the 2007 decision, and that there is good reason to believe that it has declined.

2.6 Conclusion

Q. Overall, what do you conclude from your "top down" review of Columbia's equity cost claim?

A. Columbia's claimed cost of equity of 11.25 percent does not pass a "smell test." A respected and independent analysis firm concludes that the natural gas distribution industry has exhibited a declining cost of equity capital for more than a decade. A variety of very different equity costing methods suggest that the natural gas distribution industry equity cost of capital is below, and perhaps well below, 10.0 percent.

Other regulatory commissions, while awarding equity returns that appear to exceed the cost of equity capital implied by this independent analysis, have recently awarded equity returns to gas utilities below 10.0 percent. Pennsylvania Commission precedent also indicates that the 2007 RoE award to PPL Gas of 10.4 percent likely overstates the current cost of equity capital for Columbia. To the extent the Commission accepts one of Columbia's proposed residential rate decoupling mechanisms in this proceeding, Columbia's equity cost should be relatively lower.

All of these considerations indicate that Columbia's claim of 11.25 percent is excessive. Considering all of these factors, I suggest that the Commission begin a gradual process of moving allowed RoEs into line with the actual cost of equity. Because independent estimates of the cost of NGDC equity are consistently below 10.0 percent, I recommend that 10.0 percent be set as an upper bound for the equity cost award in this proceeding. I estimate that the impact of setting the allowed cost of equity capital at 10.0 percent would, by itself, reduce Columbia's revenue requirement by approximately $11.5 million.

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

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 tariff 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 bundled load balancing and distribution services from Columbia;

- Transportation service, in which larger business customers purchase gas supplies from NGSs, and purchase unbundled load balancing services (as needed) and distribution service from Columbia.

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

In total, the business rate classes represent about 57 percent of Columbia's total throughput, or about 44.3 of Columbia's total 77.1 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 million Dth per year.

The following are the non-residential rate class groups specified by Columbia. Because the Company's abbreviations for the rate class groups are somewhat contradictory, I have included descriptive names for these groups.

SGS/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 Choice Service and SGDS is transportation service. Within the SGS/SGDS rate class group, some 72 percent of the customers and 62 percent of the load are in Rate SGSS. The average Small General customer size is about 367 Dth per year, which is roughly four times the size of the average residential customer. The tariff sets an upper limit on Small General customers at 6,440 Dth per year, although Columbia reports that a few customers exhibit substantially higher annual throughput levels. Overall, SGS/SGDS represents about 17 percent of non-residential throughput.

LGS ("Large Sales"): All customers in this rate class group are sales service customers, taking service under Rate Schedule Large General Sales Service ("LGSS"). The minimum size for this rate class group is 6,440 Dth per year.[6] The average customer size is approximately 11,800 Dth per year. There is no upper limit on the size of customers in this group. At present, there are fewer than 80 customers taking service under this schedule, representing about 2 percent of business throughput. Although the LGS sales class eligibility rules are similar to those for the SDS transportation class, the LGS customers are more temperature-sensitive than the SDS customers, with a design day

[6] The Company proposes various small modifications to rate class eligibility rules and tariff blocks in the current filing, to reflect the conversion of its tariff to Dth (versus Mcf) billing practices and to use rounded numbers. I have no objection to these changes, and I use the updated values in this discussion.

load factor (as estimated by Columbia) of 27.4 percent for LGS compared to 46.1 percent for SDS.

SDS ("Medium Transportation"): All customers in this rate class group are transportation service customers, taking service under Rate Schedule Small Distribution Service ("SDS"). Columbia's "Small" designation for 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 SDS maximum annual throughput is 53,650 Dth per year, with an average customer size of about 16,900 Dth per year. This rate class group represents about 16 percent of non-residential throughput.

For cost allocation purposes in this proceeding, Columbia proposes to separately allocate costs to the LGS and SDS classes. This approach is consistent with the Company's approach in the 2008 and 2010 base rates proceedings, but is different than the approach in the 2011 proceeding in which the LGS and SDS classes were combined for cost allocation purposes. Because the eligibility requirements for these two rate classes are similar, and the only major difference between these rate classes is whether the customer chooses to shop, it is not clear why the Company desires to separately allocate *distribution* costs and separately design *distribution* rates between customers whose only difference is whether or not they choose to shop for gas. The Company's approach will therefore distort gas competition, because a customer who chooses to shop will not only see the elimination of the gas supply charge, but will also see a confusing change in distribution rates.

LDS ("Large Transportation"): All customers in this rate class group are transportation service customers, taking service under Rate Schedule Large Distribution Service ("LDS"). Minimum throughput is 53,650 Dth per year, matching the SDS upper limit. Average throughput for these customers is about 195,000 Dth per year. This rate class group represents about 40 percent of non-residential throughput. Some 44 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").[7] 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 214,60 Dth *and* be located within two miles of an interstate pipeline interconnection. 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 ten Mainline customers identified by Columbia represent about 12 percent of non-residential throughput.

4. <u>Cost Allocation</u>

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

A. The most important criterion for setting regulated utility rates is the cost incurred by the utility for providing the service.[8] 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. A COSS is an analytical tool with which the utility's total cost (or "revenue requirement") is allocated among each of the rate classes. These allocated costs are then used as a key input in determining the total revenues that the utility plans to recover from each rate class through tariff rates.

In using the results from a COSS 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 toward cost-based rates. Thus, rate classes whose revenues substantially exceed allocated costs are typically assigned either relatively low rate increases or rate decreases. Rate classes whose revenues are well

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

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

below allocated costs are generally assigned relatively larger rate increases than those classes whose revenues are only slightly below allocated costs.

In addition to class revenue requirement issues, a COSS provides useful cost information regarding the specific nature of utility tariff charges. In particular, a COSS 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 a COSS assign costs to the various rate classes?

A. The underlying principle of a COSS 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.

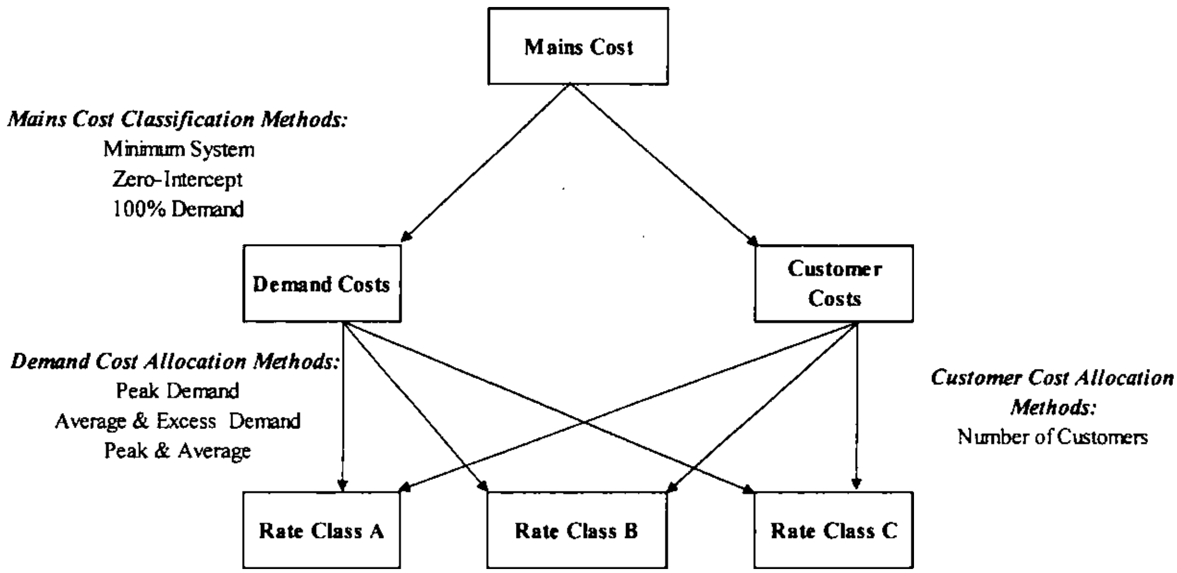
Q. What issue tends to attract the most debate in a COSS for a natural gas distribution company ("NGDC")?

A. The most contentious issue is typically that of the classification and allocation of mains plant. This debate arises for two reasons. First, mains plant tends to represent a large share of the NGDC's overall rate base, and the allocation of rate base has a strong impact on how operations and maintenance ("O&M") costs are allocated. Second, there are significant philosophical differences among utility cost allocation experts as to the appropriate method for classifying and allocating mains costs.

A graphical summary of the various common methods is shown in Figure IEc-2 below. The upper portion of the figure shows the options for *classifying* mains costs, generally into "demand-related" and "customer-related" components. The lower portion shows the options for allocating the demand-related and customer-related cost components among the various rate classes.

Figure IEc-2

Classification and Allocation of Mains Costs: Summary of Methodologies



Q. **Does Columbia classify its mains plant as shown in Figure IEc-2?**

A. Conceptually, Columbia does indeed use the basic approach shown in Figure IEc-2. However, Columbia makes two modifications to this general approach. First, consistent with its past practice, Columbia directly assigns the total costs associated with providing service to the MDS rate classes, consistent with its practice in the past three base rates proceedings. Because these large customers are generally served by short, dedicated mains, it is both simpler and more accurate to directly assign those costs to this class.

Second, and in a departure from past practice, Columbia proposes to segregate the joint-use mains costs into two categories:

- Mains that either (a) have a diameter of no more than two inches *or* are larger diameter mains that are operated at low pressure ("SDLP mains"); and,
- Mains with a diameter of more than two inches *and* which are operated at higher pressure ("LDHP mains").

Columbia estimates that the mains cost split is 44 percent for SDLP mains and 56 percent for LDHP mains. Columbia proposes to assign the SDLP mains costs only to the RS/RDS and SGS/SGDS rate class groups, while assigning the LDHP mains costs to all classes. Prior to this proceeding, Columbia assigned both categories of joint-use mains cost to all rate classes except MDS. Not surprisingly, this new proposed method serves to increase costs assigned to the smaller customer rate class groups.

Q. How does Columbia address the issue of mains plant cost classification and allocation in this proceeding?

A. As it has in the past, the Company has submitted two separate COSSs in this proceeding, based on alternative classification/allocation philosophies for mains costs.[9] These two COSSs are generally at opposite ends of the philosophical spectrum regarding cost causation for mains plant classification and allocation.

The first COSS *classifies* mains costs into demand-related and customer-related components, and then *allocates* the demand-related component of costs based on design day peak demands.[10] In this testimony, I refer to this first COSS as the CD COSS, because it uses both a customer component and a peak demand allocation factor.

The second COSS does not *classify* any costs as customer related, and *allocates* all mains costs using an allocation factor that is based both on average demand and peak demand. I will refer to this second COSS as the "P&A COSS," because it uses a peak-and-average allocation factor.

Q. How does Columbia tie together its new proposal for segregating mains by size and pressure and its two classification/allocation methods?

A. Figure IEc-3 below depicts the P&A method and Figure IEc-4 depicts the CD method. In the P&A method, the costs are "sub-functionalized" into the three categories I described

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[9] In fact, Columbia submits three COSSs in Exhibit 111, with the third method being a simple average of the other two.

[10] In its 2008, 2010 and current filings, Columbia used a "minimum system" approach for classifying mains plant costs in the CD study. In its 2011 proceeding, Columbia used a "zero-intercept" method for classifying mains plant costs.

earlier. The MDS mains are directly assigned to that class. The other two categories are both classified as 100 percent demand-related (labeled C1 and C2 in Figure IEc-3) and allocated using P&A allocation factors (labeled A1 and A2 in Figure IEc-3). However, the small diameter/low pressure mains are allocated only to the RS/RDS and SGS/SGDS rate classes, as shown on the lower left-hand side of Figure IEc-3.

Figure IEc-3
Columbia Gas Proposed Mains Cost Allocation Method: P&A Approach

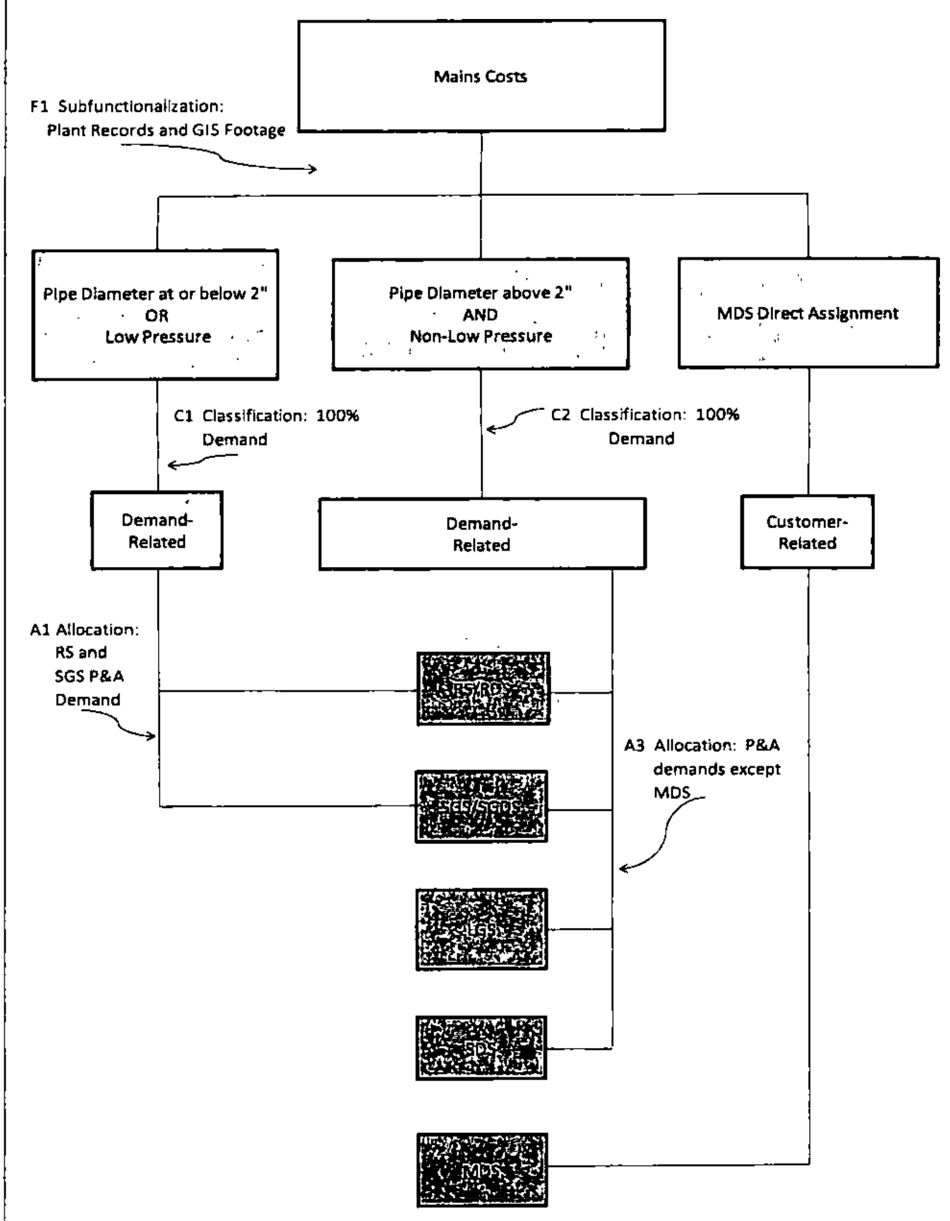
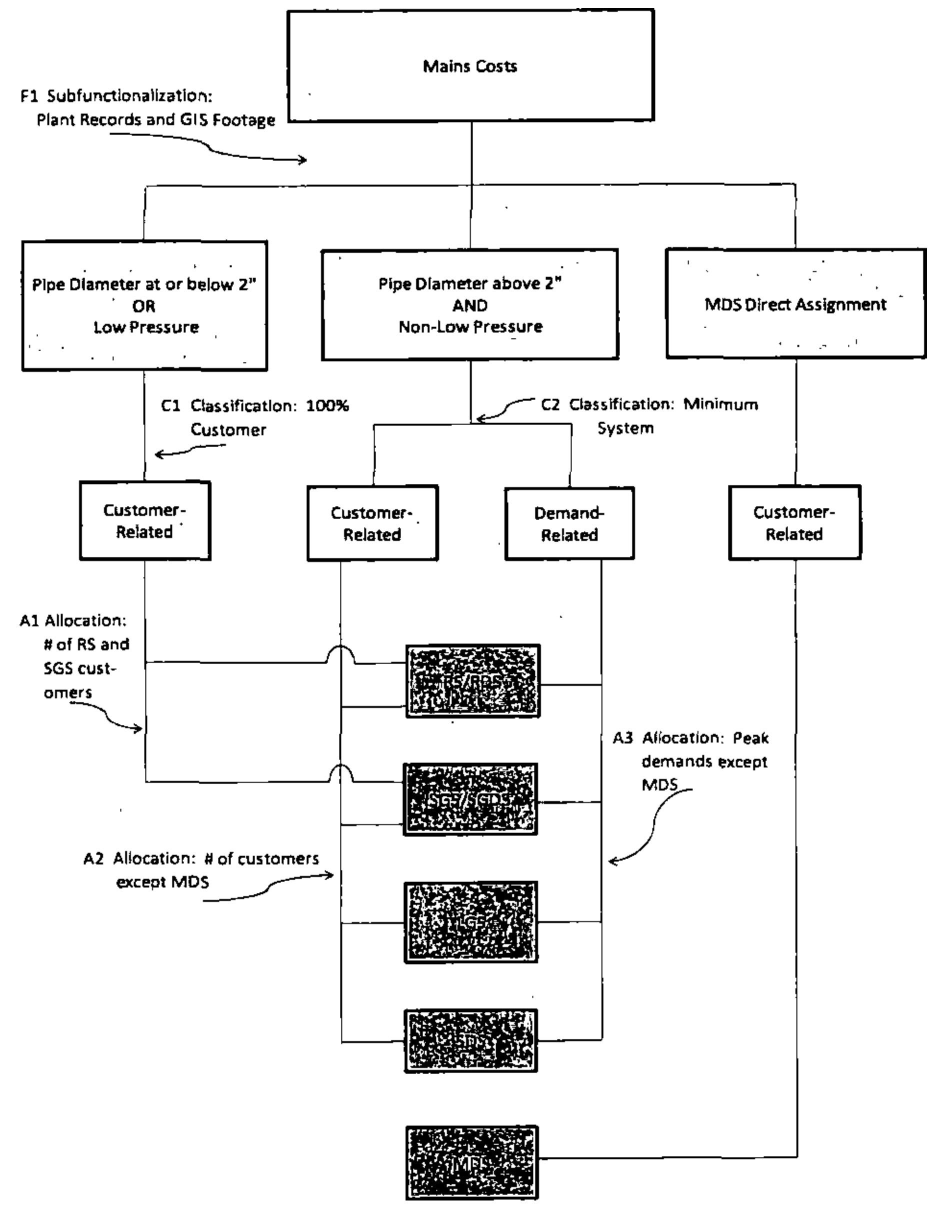


Figure IEc-4
Columbia Gas Proposed Mains Cost Allocation Method: CD Approach



In the CD COSS, the Company performs the same sub-functionalization as it does in the P&A COSS. However, it classifies all of the small diameter/low pressure mains as customer related (C1), and allocates those costs between the RS/RDS and SGS/SGDS classes based on the number of customers in those two classes (A1). For the larger diameter/higher pressure mains, the Company classifies the costs into customer-related and demand-related components using a minimum system method (C2). The customer related component is allocated based on number of customers to all non-MDS classes (A2), and the demand-related component is allocated to all non-MDS classes based on peak demands (A3).

Q. Do you agree with the Company's proposal to sub-functionalize mains?

A. Not at present. However, I acknowledge that the Company's method is not without some cost causation logic. It is based on a conceptual model in which *all* customers are served by *all* of the LDHP mains, and only smaller customers are served by the SDLP mains. Thus, if the smaller mains serve only small customers, and the larger mains proportionately serve all rate classes, the Company's approach would be reasonable. However, the Company has not demonstrated that its gas system meets these criteria, and in some cases has admitted that it does not. Moreover, the Company's proposal has several technical flaws that need to be remedied before the proposed modification can be adopted. Based on my review, the proposal has the following flaws, virtually all of which serve to overstate costs assigned to smaller customers, especially residential customers.

1. If SDLP mains are assigned only to smaller customer classes, Columbia should similarly identify all of the LDHP mains that serve only larger customers, and separately allocate the costs for those mains only to the larger classes. Columbia does not obviously do so in its proposed COSSs (except for those mains dedicated to MDS service), thereby likely overstating costs assigned to smaller customers.[11]

2. A modest but not insignificant number of customers in the larger rate classes do, in fact, take service from SDLP mains, but the Company assigns no SDLP costs to the larger customer classes associated with these customers' use of those mains.[12] Thus, some SDLP mains costs should be assigned to larger customer classes.

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[11] At this writing, I have insufficient information to determine whether Columbia has any mains that do not serve any smaller customers.

[12] See OSBA-11(e). Referenced interrogatory responses are attached as Exhibit IEc-3.

3. Some small customers are served from SDLP mains that are not downstream of LDHP mains. LDHP allocators should therefore exclude those customers. While the Company indicates that "the vast majority of 2 inch mains is also supplied by larger diameter mains," the Company does not quantify this amount. It is also unclear whether the upstream "larger diameter mains" referenced by the Company are also included in the SDLP category by virtue of operating at low pressure.[13] In effect, costs for LDHP mains are likely being assigned to some smaller customers who do not use those mains.

4. Some customers in the RS/RDS and SGS/SGDS classes are *not* served from SDLP mains.[14] The Company should therefore exclude these customers and their associated demands from the allocation factors used to assign SDLP. However, the Company has not done so. In effect, some smaller customers are being assigned costs for SDLP mains from which they receive no service. This error will overstate the costs of SDLP mains assigned to the SGS/SGDS rate classes, and understate costs assigned to the RS/RDS classes.

5. In its CD COSS, the Company classifies all SDLP mains as customer-related, despite the fact that the Company assumes that a substantial portion of those mains are of larger diameter and have a cost per foot that is much higher than the minimum system value ($14.74 per foot versus $7.63 per foot, on average).[15] A more reasonable approach for classifying these mains costs would be to apply the minimum system (or zero intercept) method to the SDLP costs as well as to the LDHP mains.[16] Doing so would reduce costs assigned to the RS/RDS classes and increase costs assigned to the SGS/SGDS classes.

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[13] See OSBA-11(h).

[14] See OSBA-I-11(g).

[15] Note that this problem may be less severe if the problem cited in item (1) is rectified.

[16] Columbia appears to agree with this conclusion. See OSBA-I-11(j).

6. In its CD COSS, the Company mis-applies the minimum system method to the LDHP mains costs. The minimum system cost is $7.63 per foot, and the average cost of LDHP mains is $20.42, implying a classification factor of 37% customer, 63% demand. In contrast, the Company incorrectly applies the *system-wide* minimum system classification factor of 52% customer, 48% demand to the LDHP mains. This error also overstates costs assigned to RS/RDS customers.

7. To determine the cost associated with the "low pressure" mains that are greater than 2-inches in diameter (which are included in the SDLP category), the Company simply assumes that the cost per foot for the low-pressure mains is the same as the cost-per foot for all mains. Instead, the Company should determine the specific cost associated with the low pressure mains, rather than relying on system average estimates.

Q. Have you attempted to correct for all of these errors in the IEc COSS?

A. No, I have not. Doing so would require access to much more information than is reasonably available to me in this proceeding. I have therefore developed the IEc COSSs based on the Company's historical approach of classifying and allocating non-MDS mains in a single cost category. To the extent that the Company can remedy these problems in its rebuttal testimony, I will reconsider the proposed approach in my surrebuttal testimony.

Q. Let's return now to the traditional mains cost allocation issue. What are your views regarding which method for classifying mains costs is most consistent with cost causation?

A. Conceptually, gas mains costs are incurred for two reasons. First, each gas main must be sized to meet the peak demand load of all customers served downstream from that main under design conditions. Larger diameter mains have higher load carrying capacity and are more costly (per foot of main) to install. For that reason, cost allocation experts recognize that mains costs have a peak demand component that is related to the capacity of the main to transport gas. Second, gas distribution mains must be constructed to interconnect each customer served by the utility to the distribution network, and eventually to the interstate gas pipeline at the city gate. The costs incurred to provide this service are related primarily to the length of the mains installed.[17] Distribution mains costs are therefore also influenced by the location of the utility's customers, relative both to each other and to the interstate pipelines. As an estimate of this distance-related cost causation factor, many utilities use customer count as a proxy. The use of this proxy is based on the reasonable hypothesis that more footage of distribution mains is required to interconnect one hundred smaller customers with a maximum demand of 1.5 Mcf per day than that needed to connect one larger customer with maximum demand of 150 Mcf per day. Or, to put it another way, gas distribution utility mains costs exhibit economies of scale with respect to the size of the customer -- large customers typically cost less to serve per unit of demand than smaller customers.

Unless a utility constructs a detailed model of mains footage serving each customer, it is reasonable to expect that larger customers are less expensive to serve, per unit of demand, than smaller customers. While the methods used by cost of service analysts for classifying costs between customer and demand components are only approximations, it is preferable to use a reasonable approximation than to adopt a methodology that is certain to be incorrect. Therefore, in the absence of a detailed modeling of the gas distribution network itself, and if care is used, I generally recommend that an estimated customer-demand classification split be used in gas distribution COSSs. The American Gas Association's <u>Gas Rate Fundamentals</u> text supports this approach.[18]

Q. If a customer component is employed, what methodologies are generally used to classify mains costs?

A. The two most common methods are a "minimum system" method and a "zero-intercept" method. The minimum system method determines the customer component of cost based on what the hypothetical total system would cost if it were all based on pipe of minimum

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[17] Other factors beyond the size and capacity of the pipe will affect the cost per foot of installed mains, including the geography, the soil conditions, and the urban/suburban/rural nature of the area served by the distribution utility. As with distance, it would be a complex matter to recognize these different cost causation factors in typical utility cost allocators or billing determinants.

[18] <u>Gas Rate Fundamentals, Fourth Edition</u>, American Gas Association, 1987, page 136.

diameter. Columbia uses a minimum system approach in its CD COSS, based on a 2-inch main. In effect, the customer component of the system represents the cost of a system with minimal load-carrying capability.

The zero-intercept method is conceptually similar, except that a statistical analysis is used to estimate the cost of a zero-diameter pipe. The customer component is derived based on the cost of a hypothetical system cost based on the zero-diameter pipe. In effect, the customer component of the system represents the cost of a system with *zero* load-carrying capability.

Not surprisingly, the zero-intercept method generally produces a lower customer component of costs, since a zero-diameter main costs less than a minimum actual size main.

Q. Do other utilities split distribution costs into demand and customer components?

A. Many do. For example, in its last base rates case (litigated during the pendency of its acquisition by UGI), PG Energy (now UGI Penn Natural Gas) proposed a zero-intercept methodology. Similarly, in a relatively recent case, National Fuel Gas presented four different cost allocation methodologies, two of which used a zero-intercept method for classifying costs. And of course Columbia's CD COSS includes a relatively large customer cost component. Also, cost allocation for electric distribution utilities faces the same issue of classifying electric distribution costs. Analysts use both minimum system and zero-intercept methodologies for electric companies. For example, PPL Electric has used a minimum system methodology for many years for secondary system plant, and recently 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.[19]

Q. Let's turn now to the issue of allocating the demand-related mains costs. What methods are in general use?

[19] *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.)

A. The AGA text Gas Rate Fundamentals identifies several methods for allocating mains demand costs: the *coincident peak* ("CP") method, the *non-coincident peak* ("NCP") method, and the *average-and-excess* ("A&E") method. In addition, some experts advocate the use of a *peak-and-average* ("P&A") method, which is also described in the AGA text as the "Seaboard" method.

The CP method allocates the demand component of mains costs to customers based on each customer class' contribution to the system peak. That is, the method recognizes benefits of load diversity in allocating costs. This method implicitly assumes that mains need only be sized to meet the diversified peak demand of its customers.

The NCP method uses each class' total peak demand, regardless of when it occurs. This method therefore recognizes no benefits of diversity among rate classes. Thus, for example, a business customer that uses more gas in the summer could have a relatively high NCP based on its summer load, but its contribution to the winter CP would be much lower. In effect, this method recognizes that at least some component of distribution mains must be sized to meet that customer's peak demand in the summer.

Both the CP and NCP demand methods are based on the premise that gas mains must be sized to meet peak demands, and that average demand is not relevant to cost causation.

In practice, there is usually little difference between CP and NCP demand allocators for temperature-sensitive rate classes (which generally comprise most of the NGDC's load). Because the loads are temperature-sensitive, rate classes tend to peak at the same time, and there is therefore little benefit to diversity. The primary difference between CP and NCP allocators comes from seasonal businesses that operate at lower levels (or do not operate at all) in the winter.

The A&E method is a hybrid allocation method, in which a portion of the demand-related costs is allocated on an average demand (or "commodity") basis, and the balance of the costs is allocated on an *excess* demand basis.

The P&A method is also a hybrid allocation method, in which a portion of the costs is allocated on an average demand basis, and the balance of the costs is allocated on a *peak* demand basis.

Q. Is the A&E allocation methodology the same as the P&A allocation methodology?

A. No, the two methods are based on different interpretations of cost causation, and often produce quite different cost allocation results.

The A&E method relies on an average demand component and an excess demand component. Recall, however, that excess demand is defined as peak demand *minus* average demand. Thus, the A&E allocator has one component based on average demand, and one component based on peak demand minus average demand. Because average demand is subtracted from peak demand in the "excess" portion of the allocator, the importance of the average demand component in the A&E allocator is reduced or eliminated.

By way of contrast, the P&A method relies on average demand and peak demand, thereby placing a greater emphasis on average demand than does the A&E method.[20] In practice, much depends on the relative weighting of the two components of each allocator. Standard practice for calculating the A&E allocator is to use a system load factor weighting for the average demand component. Thus, for example, if the system load factor is 30 percent, the average demand component is weighted at 30 percent and the excess demand component is weighted at 70 percent. The most common P&A method is to use a 50/50 weighting scheme for the average demand and peak demand components.

Q. In your opinion, what is the appropriate methodology for allocating mains demand costs?

A. Mains must be sized to meet peak demands, or the capacity will not be sufficient to provide gas to customers on the coldest day of the winter. Whether customers use gas on

[20] The P&A method is sometimes criticized for double counting average demand, because the average demand is included in both the average and the peak demand components of the allocator.

only one day of the year, or they use gas on all 365 days, the pipe simply must be sized to meet demand on the peak day. As a matter of cost causation, an NGDC does not incur any additional costs beyond those needed to serve peak day demand. For that reason, I advocate the use of a peak demand approach.

Q. What allocation methods does Columbia employ in its two COSSs?

A. In its CD COSS, Columbia uses a peak demand allocation method. In its P&A COSS, Columbia uses a 50/50 weighting of peak demands and average demands.

Q. What is the recent Commission precedent with respect to the classification and allocation of NGDC mains costs?

A. In its two most recent decisions in litigated base rates cases involving NGDC cost allocation, the Commission has approved classifying all mains costs as demand-related, and approved allocating costs using variants of the A&E demand allocator.

First, 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.[21]

Second, 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.[22]

Q. In light of this precedent, have you prepared an A&E version of Columbia's COSS?

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[21] In the PPL Gas 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.

[22] 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.

A. At the request of OSBA counsel, I have. To do so, I developed an alternative simulation of the electronic version of the Company's cost allocation model which was provided in discovery. I excluded the Company's sub-functionalization of mains into SDLP and LDHP categories, and I applied an A&E allocation factor. Also at the request of counsel, I used a 50/50 weighting for the A&E methodology. For reference, I refer to this as the IEc A&E COSS.

Q. Have you also prepared a COSS based on a mains cost allocation method that is more consistent with cost causation?

A. I have. In so doing, I relied on the zero-intercept classification analysis prepared by Columbia in its 2011 base rates proceeding. That analysis indicated that Columbia's system has only a relatively small customer component, at some 12.2 percent of costs.

Q. Do these methods produce materially different results?

A. They do indeed. Table IEc-3 compares the overall allocation of mains costs among the various methodologies that could be employed.

Table IEc-3
Comparison of Overall Mains Cost Allocation

	Columbia Proposed		***Traditional Methodology***			
	MinSys CD	***P&A***	***MinSys CD***	***ZI CD***	***A&E***	***P&A***
RS/RDS	82.9%	61.3%	76.5%	64.6%	55.8%	53.2%
SGS/SGDS	12.7%	24.1%	15.7%	21.5%	21.7%	20.9%
LGS	0.3%	0.7%	0.6%	1.0%	1.2%	1.2%
SDS	1.5%	4.3%	2.6%	4.7%	6.8%	7.6%
LDS	2.6%	9.6%	4.5%	8.2%	14.5%	17.1%
MDS	0.0%	0.0%	0.0%	0.0%	0.0%	0.0%
Total	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**	**100.0%**

Sources: IEc Workpapers

The differences among methods are very substantial. For residential customers, the class share of mains costs ranges from 53 percent under a traditional P&A method to 83 percent under the Company's method. For LDS customers, the difference is more than a factor of six in allocated costs, ranging from 2.6 percent to 17.1 percent.

Q. Beyond the issues surrounding mains classification and allocation, do you have any other specific concerns regarding Columbia's proposed COSS?

A. I have concerns about the following aspects of Columbia's proposed COSS.

- Meters costs;
- Services costs;
- Design day demands
- Industrial metering and regulating ("M&R") equipment cost allocation
- Uncollectibles costs
- Storage gas working capital allocation
- Rent revenues
- Large customer relations costs
- Sales plus Choice allocation factor error

Where appropriate, I have made modifications to both the IEc A&E COSS and the IEc ZI COSS for these factors, as discussed below.

Q. What is your concern about the Company's meters cost allocation methodology?

A. The Company uses a quasi-direct assignment method for assigning meters costs to the various rate classes. Columbia's plant records do not track meters costs by rate class. Instead, the Company groups meters into four categories, calculates the average cost per meter in each of those four categories, counts the number of meters by class in each of those four categories, and calculates a meters cost for each class based on the product of per-meter cost and number of customers, summed across the four meter categories.

As a theoretical matter, this approach is not necessarily unreasonable, except that the devil can be in the details. In this case, both the Company's underlying data and its use of broad meters category averages may be distorting the accuracy of the allocation.

First, the average unit cost per meter for the four categories is suspect. The Company's values are shown in Table IEc-4 below.

Table IEc-4 Average Meters Cost by Capacity		
Capacity in Cubic Feet Per Hour	**Columbia Cost per Meter**	**OSBA-I-14 Cost per Meter**
0 – 500	$48	$51
501 – 1,000	$471	$540
1,001 – 1,500	$232	$1,261
Over 1,500	$425	$1,992
Sources: IEc workpapers		

Columbia therefore relies on data which imply that the third and fourth largest meters are less costly than the second largest meters, a result that is both counter-intuitive and somewhat unusual. Moreover, as shown in the right-hand column of Table IEc-4, Columbia's cost per meter does not appear to agree with the figures provided in its response to OSBA-I-14, which suggest a different and more intuitive meter cost pattern. I should add that using the unit cost figures in the right hand column of Table IEc-4 would increase costs assigned to the non-residential classes, and reduce costs assigned to the residential class.

Q. Do you have other concerns regarding the meters cost assignment method?

A. I do. Based on the information provided in OSBA-I-14, I compiled the number of customers by class by meter size, which is shown in Table IEc-5 below. I included the actual test year customer count for comparison.

Table IEc-5

Meter Count by Meter Size Group

Capacity cf/h	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
0 – 500	373,390	26,906	0	18	15	1
501 – 1,000	767	6,936	52	35	9	0
1,001 – 1,500	9	821	14	19	8	1
Over 1,500	14	2,347	92	402	125	6
Total	**374,180**	**37,010**	**158**	**474**	**157**	**8**
FTY Count	**378,379**	**36,372**	**79**	**416**	**91**	**10**

Sources: IEc Workpapers

Table IEc-5 highlights some problems associated with the Company's methodology. First, the Company defines the largest meter group as having capacity over 1,500 cubic feet per hour. Unfortunately, such a definition means that the largest customers in the residential and SGS/SGDS classes are assigned the same meters cost as the largest customers in the MDS class. It is therefore very likely that this arbitrary averaging results in over-assigning costs to the smaller customer classes, and under-assigning costs to the larger customer classes.

In addition, the LGS class shows a high ratio of meters to customers, implying an average of two meters for each LGS customer. While it is possible that LGS customers are much more likely to have multiple meters than any other class, it is also possible that the Company's information systems are not properly matching meter count by class.

Finally, it should be noted that a 1,500 cubic feet per hour meter can, at most, handle about 14,000 Dth per year, for a customer using exactly the same amount of gas in every hour. In all likelihood, even the smallest LGS and SDS customers will have peak hourly demands in excess of 1,500 cubic feet, and the LDS and MDS customers have maximum hourly demands far in excess of 1,500 cubic feet. This implies that, at a minimum, the meters costs assigned to the MDS class are understated (since there are only six meters in the largest group), and the meters costs assigned to the SDS class are likely to be understated (the number of maximum size meters is less than the customer count).

Q. Have you attempted to correct for the meters cost anomalies in the IEc COSS?

A. I have not, for two reasons. First, there may be reasonable explanations for these problems, such as data constraints or meter age factors that Columbia has not yet offered in defense of its method. Second, I simply do not have enough information to develop a more credible cost assignment method. Depending on the nature of the Company's rebuttal testimony, I may attempt to reduce the impact of these problems in my surrebuttal testimony, if the impact is material.

Q. What is your concern about the services cost allocation factor?

A. As is the case for meters costs, Columbia's information systems do not track services costs by customer class. Columbia therefore combines services into two categories, namely those under 3 inches in diameter and all others. (Except for a handful of 2-½ inch services, the smaller services group consists of services with diameters at 2 inches or below. For the most part, Columbia does not track differences in service size at 2 inches or below.) Columbia calculates average cost for each category ($612 per smaller service and $880 per larger service respectively), and applies those averages to the service count for each category for each class. The vast majority of service lines fall into the smaller size category, including a majority of the service lines in the LGS, SDS and LDS rate classes. In effect, the Company assumes that the service line cost for each of these larger customers is the same as that for a residence or small business. As is the case with the meters allocation, this aggressive averaging method is likely to over-assign costs to smaller customers to the benefit of larger customers.

Q. Have you modified the Company's services allocation method in the IEc COSS?

A. Not at this time. As is the case with meters, there is simply insufficient information available to develop a more reasonable cost estimate. However, I have updated the service cost allocation to reflect the error in the Company's filing as identified in the response to OSBA-I-21(b).

Q. What are your concerns about the design day demand allocation factor?

A. Columbia presents its design day demands in the annual Section 1307(f) proceedings. It is my understanding that the design day demands used for the Company's COSS for the smaller customer rate classes are based on that study. As this methodology is annually approved by the Commission, I have not evaluated it in detail in this proceeding for the RS/RDS and SGS/SGDS classes, for which Columbia has responsibility to provide design day deliverability capacity.

Regarding the larger customer classes (LGS, SDS, LDS and MDS), I performed a simple test of the Company's demand allocation factor. Columbia uses "design day" as its allocation factor for all customer classes. However, for large customers, the distribution system must generally be sized to meet the demand for the customer on the customer's peak day, rather than on a system peak day. (For small customers, the design day is the same as the customer's peak day.) Based on confidential information provided by the Company, I estimated the maximum demand for each customer in each of the large rate classes, for each year from 2007 to 2011.[23] I set the maximum demand at the greater of (a) the average daily usage of the customer in its peak month, and (b) the statistical relationship between the customer's load and heating degree days, measured at a design day temperature (-5 degrees F.). This method is conservative, in that it assumes that non-weather sensitive customers' consumption is level throughout the customer's peak month, and because it ignores the impact of Columbia's other design weather criteria, namely the preceding day temperature and windspeed.

Based on this analysis, the peak day demands used by Columbia for the LGS class are consistent with those used in my analysis, but the design day demands for the SDS and LDS classes used by Columbia are well below the peak demands implied by my analysis. Table IEc-6 below compares the class load factors implied by the Company's design days and my estimate of customer peak demands.

[23] The details of this analysis are available in the IEc Workpapers.

Table IEc-6 Estimated Peak Demand Load Factors			
	LGS	**SDS**	**LDS**
2007	28.5%	31.3%	50.7%
2008	28.9%	28.7%	40.7%
2009	26.9%	29.0%	47.6%
2010	27.7%	32.4%	56.9%
2011	27.05	32.0%	53.4%
Average RDK	**27.8%**	**30.7%**	**49.9%**
Columbia	27.4%	46.1%	66.6%
Sources: IEc workpapers.			

I therefore modified the peak demands for the SDS and LDS classes in the IEc COSS to be consistent with the average class load factors that I estimated from the historical data.

In addition, I note that there appear to be two relatively minor errors associated with the translating the design day forecast into rate class design day demands for cost allocation purposes, relating to NSS demands and residential PPS demands.

Regarding NSS, Columbia includes NSS volumes and revenues in the MDS class for cost allocation purposes. However, the Company appears to include NSS design day demands for 2013-2014 in the SGS/SGDS class.[24] By including these NSS peak demands in that class, costs are being assigned to SGS/SGDS customers, while the revenues associated with that service are credited to the MDS class. I modified the peak demand allocators to shift NSS demands from the SGS/SGDS class to the MDS class.

[24] The Company's response to OSBA-I-12(b) suggests that these demands are related to customers that are no longer taking NSS service. This response is inconsistent with the cost allocation study, which explicitly states that that these demands are for 2013-2014. Moreover, if these customers have shifted to SGS/SGDS since the development of the cost allocation study, all revenues, volumes and demands for these customers should be shifted from ____??

Regarding residential PPS service, Columbia appears to have inadvertently included these demands in the SGS/SGDS class. In the IEc COSS, I moved those demands from SGS/SGDS to RS/RDS.

Q. What is your concern regarding the allocation of Industrial M&R equipment?

A. As is the case with meters and services, Columbia does not track Industrial M&R equipment by rate class. Columbia simply calculates the average cost for an M&R station, and applies that to the number of M&R stations in each rate class.[25] In effect, Columbia assumes that the cost for an M&R station for an SGS customer is the same as that for a much larger LDS customer. This assumption is unlikely at best, and is contradicted by the Company's direct assignment data for the MDS class. The average cost for a non-MDS M&R station is $6,856, while the average cost for an MDS Station is $20,474, implying that M&R station costs do, in fact, increase with customer size. Columbia's assumption of a uniform cost per station will therefore over-assign costs to smaller customers.

Q. Have you modified the IEc COSS to reflect this cost pattern?

A. I have. Based on the average cost per station of non-MDS and MDS customers, I calculated a linear relationship between unit cost and average size customer. I applied this relationship to derive an alternative allocation factor. This change has only a relatively modest impact on the allocation of these costs.

Q. Turning to the issue of uncollectibles costs, please first explain how Columbia allocates its uncollectibles costs by rate class.

A. Consistent with the theme of this testimony, Columbia does not track uncollectibles by rate class.[26] However, Columbia breaks up its uncollectibles costs into four categories and allocates them separately.

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[25] In its response to OSBA-I-23(b), Columbia denies that it uses this methodology. Nevertheless, the Company's electronic COSS workpapers at "Alloc 17-DA Ind M&R" = demonstrates that each M&R station is costed at $6,856 per station, regardless of the rate class.

[26] To be more precise, as Columbia states in OSBA-I-26(b), the information is "not routinely generated." The information appears therefore to be available in Columbia's information systems somewhere; Columbia may deem cost allocation to be of insufficient importance to justify the effort of extracting it.

By far the largest component of uncollectibles cots, at some $8.5 million, is that directly related to the Company's universal service programs. These costs are assigned solely to the residential class, consistent with long-standing Commission precedent.

Second, Columbia identifies uncollectibles costs related to its gas supply function. These costs are allocated between the RS/RDS and SGS/SGDS rate classes based on purchased gas cost commodity ("PGCC") revenues. In effect, Columbia assumes that the uncollectibles rate for residential and small commercial customers is the same. This allocation method is also reflected in Columbia's merchant function charge ("MFC") through which Columbia recovers these costs, which is set at a proposed 1.458 percent rate for both of these classes.

The balance of the uncollectibles costs relates to distribution service. However, Columbia has two separate billing systems, and it calculates uncollectibles separately for each. The Distributive Information System ("DIS") relates to residential and most SGS/SGDS customers, while the Gas Measurement Billing and General Transportation Systems ("GMB/GTS") relate to the larger customers. Uncollectibles in each of these two groups are allocated among the applicable rate classes based on revenues, again implicitly assuming that the uncollectibles rate is the same for all customers within each system.

Q. Is it reasonable to assume that the uncollectibles rate (net of universal service uncollectibles) is the same among all rate classes?

A. No, it is not. The rate of uncollectibles is typically much higher for residential customers than for non-residential customers. The Commission is well aware of this fact, because the other Pennsylvania NGDCs generally set substantially lower MFC rates for non-residential customers than for commercial customers.[27] In addition, in Columbia's response to OSBA-I-26, Attachments A and C show that the charge-off rate for residential customers is much higher than for non-residential customers, and the

[27] For example, the MFC rates for residential and Small C&I customers at 2.23%/0.23%,2.19%/0.36%, 3.2%/0.40%,2.26%/0.14%, and, 5.57%/1.45% at NFG Distribution, UGI Gas, UGI PNG, UGI CPG, and PGW (proposed) respectively.

delinquent bills rate for residential customers is much higher than for non-residential customers, even adjusting for the high rate of universal service uncollectibles.

Q. Have you made a correction for this problem?

A. Yes. Based both on the pattern of aging receivables and the pattern of class charge-offs reported by the Company in OSBA-I-26, I estimated the share of uncollectibles related to the residential class and the non-residential classes. (For non-residential customers, I retained the Company's allocation, as I have no better information.) I applied the residential factor (94.8 percent) to Columbia's total claimed uncollectibles costs, and deducted the uncollectibles costs related to the universal service programs. I then used the resulting uncollectibles allocation factor to assign the gas cost uncollectibles between RS/RDS and SGS/SGDS and the distribution uncollectibles among all of the classes.

Q. Is your proposal consistent with the pattern at other NGDCs?

A. My correction is relatively conservative, in that it still implies an uncollectibles rate for non-residential customers that is relatively high compared to non-residential uncollectibles rates at NGDCs that track uncollectibles by rate class. Specifically, my approach results in an implied MFC of about 1.7 percent for residential customers and 0.8 percent for non-residential customers.

Q. What is your concern regarding the allocation of storage gas working capital costs?

A. The Company allocates gas storage working capital ("SGWC") costs on the basis of sales plus Choice volumes. For the reasons discussed below in my review of the proposed GPC, I agree that these costs should be assigned to both non-shopping and Choice shopping customers. However, the Company's volumetric allocation of SGWC costs is generally not consistent with cost causation, because storage costs are more accurately related to *excess* winter over summer gas volumes. For example, a 100 percent load factor customer requires no storage services, and therefore should be assigned no storage costs. Nevertheless, the Commission's policy with respect to storage costs for most Pennsylvania NGDCs has historically been to allocate storage costs on a volumetric basis. I therefore accept the volumetric approach based on precedent, rather than cost causation.

I have, however, modified the Company's COSS to correct the error identified in OSBA-I-12(a), wherein Columbia inadvertently excluded Rate SCD volumes from the allocation factor. As with many of my corrections, this modification will increase costs assigned to non-residential customers.

Q. What is your concern about the allocation of rent revenues?

A. Rent revenues are earned from leasing company facilities. Therefore, these revenues should serve as an offset to facility costs. Rather than allocate these revenues on a per-customer basis, I allocate these costs using the same allocation factor that applies to general plant.[28] In effect, the revenues serve as an offset to costs, and should be allocated in the same manner.

Q. What is the issue with allocation of large customer relations cost?

A. I correct for the error identified in the Company's response to OSBA-I-25 regarding the number of customers in each rate class served by the Company's large customer relations group.

Q. What is the issue with allocation Factor 25 in the Company's COSS?

A. Factor 25 represents sales plus Choice loads. The Company inadvertently excluded rate class SCD from the allocation factor, and I have corrected this error.[29] This correction also increases costs assigned to the SGS/SGDS rate class.

Q. What is the quantitative impact of your changes to the Company's COSSs?

A. Table IEc-7 below shows the class rates of return at present rates under the Company's two COSS methods and my two COSS methods.

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[28] See OSBA-I-24(b).

[29] See OSBA-I-12(a).

Table IEc-7 Class Rates of Return: Alternative COSS Methods				
	Columbia Methods		**IEc COSSs**	
	CD	**P&A**	**ZI**	**A&E**
RS/RDS	3.4%	3.9%	3.8%	4.6%
SGS/SGDS	7.6%	2.9%	4.3%	4.1%
LGS	8.4%	3.5%	4.8%	3.5%
SDS	43.9%	13.0%	5.8%	3.6%
LDS	34,6%	5.3%	4.4%	0.8%
MDS	269.2%	269.2%	273.7%	273.7%
Total	**4.1%**	**4.1%**	**4.1%**	**4.1%**
Sources:				

5. Revenue Allocation

Q. What is revenue allocation?

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

Q. What are the 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:[30]

- 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.

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

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

A. Table IEc-8 below compares Columbia's proposed revenue allocation to the revenue increase required to achieve cost-based rates under each of its COSS methods. In general, the Company's proposed revenue allocation is reasonably consistent with its COSS results, particularly the P&A COSS result. For the larger rate classes, the Company's P&A COSS implies rate decreases for Rates SDS and MDS and an increase for Rate LDS. Columbia proposes minimal increases for each of those rate classes, which has the advantages of simplicity and maintenance of the existing rate relationships between the classes. For the RS/RDS and LGS classes, the Company proposes an increase that is reasonably close to that implied by the P&A COSS. For the SGS/SGDS class, the proposed increase lies between the increase implied by the two methods, but materially closer to the P&A analysis. If the Company's overall approach to cost allocation is adopted, I do not believe that the Company's proposal is unreasonable.

[30] See, for example, Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, pages 383 to 387. Please note that these criteria 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.

Table IEc-8
Summary of Columbia Revenue Allocation Proposal
($mm)

	Total	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
Columbia Proposed Revenue Allocation							
Current Revenues	$229.1	$166.1	$37.9	$1.56	$9.53	$12.86	$1.50
Increase	$77.3	$61.7	$14.4	$0.58	$0.59	$0.02	$0.02
Percent	33.7%	37.2%	38.0%	37.3%	6.2%	0.2%	0.1%
CD COSS							
Cost-Based Increase	$77.3	$90.2	$2.2	$0.01	($6.51)	($7.56)	$(1.06)
Percent	33.7%	54.3%	5.9%	0.7%	-68.3%	-58.8%	-85.1%
P&A COSS							
Cost-Based Increase	$77.3	$56.4	$20.1	$0.59	($2.17)	$3.48	($1.06)
Percent	33.7%	34.0%	53.1%	37.9%	-22.8%	27.1%	-85.1%
Sources: IEc Workpapers							

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

A. No. As I indicated earlier, the Company's proposed change to its long-standing cost allocation methodology is unduly biased against smaller customers. I therefore recommend that revenue allocation be based on my COSS analysis. However, at the end of the day, despite a wide array of changes and very different costing methodologies, my proposals for revenue allocation to the SGS/SGDS rate class are only slightly different than that proposed by the Company. The large differences involve the residential and larger industrial customer classes.

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

A. I have developed two revenue allocation proposals, based on the two IEc COSS methods.

Q. Did you explicitly consider factors other than allocated cost in developing these proposals?

A. I did. Columbia has a number of "flex rate" customers who are currently served at rates below the regular posted tariff rates. These customers generally have some opportunity to bypass Columbia's distribution system, by converting to an alternative fuel, taking service directly from an interstate pipeline, or switching to a different NGDC. By offering these customers discounted rates, Columbia argues that it can retain some margin from these customers that would otherwise be lost, thereby benefitting all remaining customers. In effect, this is a *value of service* consideration.

Q. How did you reflect flex rate customers in your revenue allocation proposals?

A. While Columbia has flex rate customers in the SGS/SGDS, SDS and LDS rate classes, the only rate class with a significant flex rate load is the LDS class. Because, flex revenues are below 1 percent of revenue for the other two classes, I did not explicitly consider them in my analysis.

For the LDS class, I split the flex rate customers into two categories, namely "NGDC Bypass" and "Other Bypass." NGDC Bypass represents the ability of a customer to shop among competing NGDCs with overlapping service territories in what is often erroneously referred to as "gas on gas competition." The Other Bypass category consists of alternative fuel and interstate pipeline bypass threats.

For the "Other Bypass" customers, I accept the Company's claim that it cannot increase rates to those customers. I also assume that the revenue shortfall associated with those customers should be reasonably shared among the rest of the rate classes. For the "NGDC Bypass" customers, I recommend that the Company move these customers to regular tariff rates.

Q. You recommend eliminating discounts for NGDC Bypass customers. Doesn't competition among NGDCs result in more accurate and economically efficient pricing?

A. No it does not. "Gas-on-gas competition" is a misnomer. NGDCs are not competing to serve these customers by aggressively looking for ways to reduce costs – they are competing to serve these customers by lowering rates to these specific customers and increasing the rates for all other customers. This is neither efficient nor equitable. It is simply a matter of cross-subsidization from those ratepayers who do not have multiple NGDC supply options to those ratepayers who do. My rationale for opposing this form of rate discrimination is no different than it was sixteen years ago, when I made a similar recommendation. In the T.W. Phillips Gas & Oil Company ("TWP") 1995 base rates case, I testified:

> *As a general matter, I am a strong supporter of introducing more competition into the business of public utilities. In many cases, unbundling services and deregulating some aspects of utility business has brought substantial benefits to all ratepayers. However, the 'competition' between [NGDCs] that gives rise to TWP's extensive use of its CRA Rider is not the type of competition that leads to lower cost, more efficient service. From an economic perspective, the discounting behavior of [NGDCs] with overlapping service territories is not competition at all -- it is price discrimination. Those customers who are fortunate enough to have access to more than one [NGDC] are awarded lower rates, while those customers who have no such options are discriminated against. There is no net benefit. Few non-regulated businesses in a competitive environment have such an option. Unlike [NGDCs], they have no monopoly customers from whom they can recover the special discounts offered to specific customers. . . .*
>
> *I recommend that [NGDCs] be allowed to compete between each other only on the basis of posted tariff rates that are paid by customers in both the monopoly and overlapping service territories. However, I do not think that this recommendation can or should be unilaterally applied to TWP in this proceeding. To do so would have grave financial implications for TWP. Instead, I suggest that the Commission undertake a formal investigation into the costs and benefits of its policy for allowing competition between [NGDCs].*[31]

Q. The Commission has undertaken a generic proceeding regarding this issue. Should the issue of Columbia's NGDC Bypass customers be deferred pending resolution of that proceeding?

A. I do not believe so. This issue has been kicked down the road for far too long already. It would be hard to identify any particular type of rate design that violates as many of the standard rate design criteria as gas-on-gas "competitive" rates. Such rates are not cost-based, they are not effective for recovering the revenue requirement, they are neither stable nor predictable (NGDCs can compete at any time), they are horizontally inequitable (equals are not treated equally), they are not dynamically efficient (neither the utility nor the customer has any incentive to use energy efficiently), they are not

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[31] OSBA Statement No. 1, Direct Testimony of Robert D. Knecht, Docket No. R-00953406, October 13, 1995, pages 41-43.

understandable (at least from the perspective of customers who cannot get the same discount) and they are not free from controversy.[32] I recommend that the Commission not include a revenue shortfall for NGDC Bypass customers in Columbia's revenue requirement in this proceeding, and that it not allow any other NGDC to offer any of those specific customers a below full-tariff rate. Pending resolution of the generic proceeding, Columbia should be free to continue to offer some or all of the existing discounts on its own nickel.

Q. Please describe your revenue allocation proposal if the IEc A&E COSS is adopted.

A. With the caveat that I developed this proposal at the request of counsel, I recommend the following:

- Under the A&E COSS, current revenues for the LGS, SDS and LDS rate classes fall far short of allocated costs. In recognition of the principle of rate gradualism, I limit the increase to these classes to 1.5 times system average, which implies an increase just over 50 percent (1.5 * 33.7% = 50.6%). For the LDS class, this increase can be achieved by assigning the 50.6 percent increase on regular rate customers, and moving the NGDC Bypass customers to full tariff rates.

- Because the MDS class is over-recovering allocated cost, I retain the Company's proposal for a minimal increase.

- For the RS/RDS and SGS/SGDS rate classes, I assign the revenue needed to bring rates into line with allocated cost, plus a sharing of the net shortfall from the larger customer classes. I allocate the shortfall in proportion to current revenues.

As shown in Table IEc-9 below, this proposal substantially moves rates into line with allocated costs (as measured by the IEc A&E COSS).

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[32] For a standard list of criteria for a sound rate design, see Principles of Public Utility Rates, Second Edition, Bonbright, Danielsen, Kamerschen, 1988, pages 383 to 387.

Table IEc-9 IEc Revenue Allocation Proposal: IEc A&E COSS				
	Increase ($000)	**Percent Increase**	**Class RoR Present**	**Class RoR Proposed**
RS/RDS	$49,913	30.1%	4.6%	9.0%
SGS/SGDS	$15,272	40.3%	4.1%	8.9%
LGS	$ 791	50.6%	3.5%	8.2%
SDS	$ 4,824	50.6%	3.6%	8.7%
LDS	$ 6,510	50.6%	0.9%	4.4%
MDS	$ 1	0.1%	273.7%	274.0%
Total	**$77,311**	**33.7%**	**4.1%**	**8.5%**
Sources: IEc Workpapers				

Q. Please describe your revenue allocation proposal if the IEc ZI COSS is adopted.

A. Under the IEc ZI COSS, I recommend the following for revenue allocation:

- As with the IEc A&E COSS, I accept the Company's proposed minimal increase for Rate MDS.

- For the other rate classes, it would be possible to simply apply increases that would bring average rates into line with allocated costs without imposing unduly large increases on any particular class. However, due to the relatively high percentage of flex rate customers in Rate LDS, such an approach would be inequitable for the non-flex LDS customers. Therefore, for Rate LDS, I estimate that a $1.63 million increase would be sufficient to move rates into line with allocated cost, if all customers were paying full tariff rates. That $1.63 million can be recovered by (a) moving NGDC Bypass customers up to regular tariff rates ($1.17 million), and (b) applying an increase on all customers for the balance ($0.46 million). Since Other Bypass customers will see no increase, the net effect is an increase of $1.17 million plus $0.37 million or $1.55 million.

- The $1.55 million increase for LDS results in a $3.16 million shortfall that needs to be allocated to the other customer classes. I recommend that it be allocated among all non-MDS classes (including LDS) in proportion to class revenue requirement. In effect, the rate increase for the RS/RDS, SGS/SGDS, LGS and SDS classes is the increase necessary to bring rates into line with allocated costs, plus a relatively small adder to pay for the LDS shortfall. This results in class rates of return for those classes just slightly above system average.

A comparison of my proposed revenue allocation based on the IEc ZI COSS method and the Company's full revenue requirement is shown in Table IEc-10 below.

Table IEc-10
IEc Revenue Allocation Proposal: IEc ZI COSS

	Increase ($000)	Percent Increase	Class RoR Present	Class RoR Proposed
RS/RDS	$58,939	35.5%	3.8%	8.6%
SGS/SGDS	$13,811	36.5%	4.3%	8.7%
LGS	$ 565	36.1%	4.8%	8.6%
SDS	$ 2,193	23.0%	5.8%	8.7%
LDS	$ 1,802	14.0%	4.4%	6.0%
MDS	$ 1	0.1%	273.7%	274.0%
Total	**$77,311**	**33.7%**	**4.1%**	**8.5%**

Sources: IEc Workpapers

6. Rate Design Issues

6.1 GPC

Q. Please summarize the salient features of the Company's proposed gas procurement charge ("GPC").

A. Pursuant to the Commission's June 23, 2011 Rulemaking at Docket No. L-2008-2069114, the Company proposes to establish a GPC for recovery of certain costs related to its gas procurement function that have heretofore been recovered in base rates. The GPC will apply only to purchased gas cost ("PGC") sales customers, and will therefore be a charge that customers can avoid by shopping. Per the Commission's order, the GPC will be part of the price to compare ("PTC"). The objective of the Commission's order is to balance the playing field between NGDCs and competing natural gas suppliers ("NGSs"), by insuring that all costs related to gas procurement are included in the PTC.[33]

In the Company's proposal, the cost basis for the GPC includes labor, benefits and overhead costs associated with employees directly involved in gas procurement activities, as well as certain legal costs associated with the annual Section 1307(f) proceedings. Columbia explicitly proposes to exclude information systems costs and storage gas working capital ("SGWC") costs from the GPC.[34] Because the Company is not making a cash working capital cost ("CWC") claim in this proceeding, the issue of gas procurement CWC is essentially moot. Moreover, because the Company is making this proposal in the context of a base rates proceeding, the issues related to base rates reductions, revenue neutrality and single-issue ratemaking that have arisen in other NGDC GPC proceedings do not apply. Columbia has included the costs associated with the GPC in its overall revenue requirement, and it has included the GPC revenues from sales customers in its proposed revenues.

With this methodology, the Company calculates that the GPC is 1.44 cents per Dth.

Q. Do you agree with the Company's proposal to exclude information systems costs related to gas procurement from the GPC?

A. No, I do not. This issue falls into the "incremental cost" versus "fully allocated cost" debate for assigning costs to competitive utility services.

Columbia relies on the traditional incremental cost argument, which was generally the basis for the retail unbundling of the natural gas industry in Pennsylvania more than a decade ago. Under that argument, the only costs assigned to competitive services are those that would be avoided by the utility if a customer chooses to shop. In this case,

[33] See, in particular, *Advance Notice of Final Rulemaking*, Docket No. L-2008-2069114, Order Entered August 10, 2010, page 1.

[34] See OSBA-I-28.

Columbia argues that its information systems costs would all need to be incurred with or without the gas procurement function, and the costs should therefore be excluded from the GPC. The logic behind the incremental cost argument is that if any "fixed" costs are assigned to the competitive services, the costs for non-shopping customers will increase when other customers choose to shop. This argument has a nice academic pedigree, and has heretofore been the basis for Pennsylvania policy.[35]

The Commission's recent rulemaking, however, does not focus on the short-term economic efficiency benefits of the incremental cost methodology, but instead focuses on the desire to promote competition and level the playing field between the NGDC and the NGS. Thus, rather than ask whether a particular cost is avoidable if a customer shops, the question is whether a particular cost is incurred by both the utility and its competitors. If the cost is incurred by both types of competitors, then leveling the playing field requires that the cost be reflected in the prices offered by both the utility and its competitors. In this particular case, NGSs certainly incur some information systems costs related to gas procurement, and therefore excluding them from the utility's GPC would put the NGSs at a competitive disadvantage.

Thus, while I understand the theoretical basis for the Company's argument, I do not agree that it is consistent with the intent of the Commission's rulemaking.

Q. Do you have any other reason to believe that the Commission intended the NGDCs to include non-incremental information systems costs in the GPC?

A. I do. The Commission explicitly identified a variety of acquisition, management and hedging costs, including associated administrative costs, all of which typically require information systems, as cost elements for the GPC.[36] In so doing, the Commission could hardly have been unaware that many such costs are basically fixed, and would be incurred by the NGDC regardless of the level of shopping.

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[35] See, for example, Transmission Pricing and Stranded Costs in the Electric Power Industry, Baumol, William J. and J. Gregory Sidak, 1995.

[36] 52 Pa. Code § 62.223(b)(1).

Moreover, other Pennsylvania NGDCs have also proposed to include information systems costs in the GPC (except where information systems are fully depreciated), including Peoples Gas, PECO, UGI Gas, UGI Penn Natural and UGI Central Penn.[37]

Q. Have you made an estimate of the information systems costs related to gas procurement that should be included in the GPC?

A. Not at this time, as I have no reasonable basis for doing so. I recommend only that the Commission direct the Company to develop a reasonable allocation.

Q. Do you agree with the Company's proposal to exclude SGWC from the GPC?

A. I understand and accept the Company's logic for excluding SGWC from the GPC. However, I have an alternative proposal.

Q. Please address the Company's logic for excluding SGWC from the GPC.

A. The Company's logic is based on the nature of its Choice program, in which the Company incurs storage costs for both sales and Choice customers. Under the Company's Choice program, retail suppliers generally deliver gas to the Columbia city gate at 100 percent load factor, meaning they supply the same amount to Columbia on each day of the year. (Columbia assigns transmission capacity to the NGSs which they can choose to use to meet this requirement.) Columbia then uses its storage capacity to balance supplies with the actual loads for the NGSs' customers. For that reason, the costs for storage capacity are included in the purchased gas demand charge, which applies to both sales and Choice customers.

The issue of SGWC is a little more complicated, however. If Columbia required NGSs to provide enough gas in the injection season to meet their customers' winter requirements, then the NGSs would, in fact, be incurring their own SGWC costs. If that were the case, then Columbia's SGWC would be related only to PGC customers, and SGWC should be included in the GPC.

[37] A comparison of the costs included in various NGDC GPC filings is included in my workpapers.

However, as explained in OSBA-I-28(d), the Company requires only that NGSs begin filling storage in August, rather than much earlier in the year. Thus, the NGSs do not, in fact, provide sufficient gas to meet their customers' winter needs, and must therefore borrow against the Company's gas in storage. Based on my rough calculations, it appears that, under this policy, Columbia is providing at least as much gas in storage working capital to the NGSs as to its own PGC customers.

Columbia argues, therefore, that since it provides the same SGWC services to both sales and Choice customers, the SGWC costs should remain in base rates. The Company then allocates the SGWC costs among the RS/RDS, SGS/SGDS, LGS and NSS classes based on sales plus Choice volumes.

Q. Why, then, do you disagree with the Company's proposal?

A. SGWC costs are gas procurement costs, and should be recognized as such. To the extent that the Company incurs SGWC costs for sales customers, those costs should be reflected in gas supply charges to sales customers. To the extent that the Company incurs SGWC costs for Choice customers, it should recover those costs from either gas supply charges to Choice customers or from charges to the NGSs.

Including SGWC costs in base distribution rates creates the potential for mischief, which is indeed a problem for Columbia. In particular, the base rates distribution charges for SGS (sales), SCD (Choice) and SGDS (regular transportation) customers are identical. They therefore all include costs for SGWC. However, Columbia is only incurring SGWC costs for the SGS and SCD customers. Thus, the Company is implicitly requiring SGDS transportation customers to subsidize other customers.

It is therefore more accurate to treat these costs as what they are, namely gas procurement costs.

Q. What is the magnitude of the costs involved?

A. Columbia's filing includes a rate base claim of $78.32 million for storage gas that is allocated based on sales plus Choice volumes. At the Company's full proposed pre-tax rate of return, that amount translates to an annual revenue requirement of some 23 cents per Dth of sales plus Choice load.[38] This amount obviously dwarfs the 1.4 cent per Dth GPC proposed by the Company.

Q. What, then, do you propose?

A. I propose that SGWC costs be included in the GPC. I similarly propose that SGWC costs related to Choice customers be charged to those customers. However, rather than impose those costs directly on Choice customers, I suggest that the charges be billed to Choice NGSs. NGSs can then pass those costs on to their own customers as they see fit.

Moreover, rather than necessarily require NGSs to pay the SGWC charge, I recommend that Columbia give the NGSs the option of either (a) retaining the existing storage fill timing requirements and paying the SGWC charge, or (b) assuming responsibility for filling storage starting in April rather than August. This approach would essentially allow NGSs a wider opportunity for cost competition, by including financing costs in the mix. To the extent NGSs can obtain lower financing costs than the NGDC, both ratepayers and NGSs will benefit. To the extent NGSs cannot arrange more favorable financing, they simply pay the NGDC for the services provided by the NGDC.

Q. If your approach is adopted, do you have any further recommendations regarding the nature of the GPC?

A. I do. Under my proposal, virtually the entire GPC would be related to SGWC. Storage gas costs are likely to cycle up and down with the price of gas, much in the way that uncollectibles costs cycle up and down with the price of gas. Therefore, rather than impose the GPC (and the SGWC charge on NGSs) as a flat, per-Dth fee, it would be more accurate to impose the GPC as a percentage of the PGC. In effect, the GPC would be structured in exactly the same way as the merchant function charge ("MFC").

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[38] In making this calculation, I apply the overall proposed weighted average cost of capital. It is certainly possible that the Company's storage gas financing is more short-term in nature than rate base assets in general, and that the weighted average cost of capital for storage gas should therefore be based on shorter-term financing costs. However, storage gas comprises nearly 8 percent of rate base, whereas the Company's total short-term debt claim is for only 3.57 percent of the capital structure, suggesting that storage gas (for whatever reason) is substantially financed by long-term debt and equity. I have therefore simply relied on the average.

6.2 Pass-through Charge

Q. The Company is proposing a Pass-through charge in an effort to simplify the many and varied charges in the tariff. Can you identify all of the pieces to Residential and Small C&I customer bills?

A. At present, Residential and Small C&I customers may be subject to the following charges:

- Customer Charge: A flat monthly rate for all customers related to distribution costs, which Columbia proposes to rename "System Charge."
- Commodity Charge: A per-Dth charge for all customers related to distribution costs, which Columbia proposes to rechristen a "Usage Charge."
- PGCC: The purchased gas commodity charge, which applies to sales customers only (RSS, SGSS).
- PGDC: The purchased gas demand charge, which applies to sales customers (same as above) and Choice customers (RDS, SCD). It does not apply to regular transportation customers under Rate SGDS. Choice customers pay for gas supply demand charges because Columbia provides load balancing for those customers.
- GCA: The Gas Cost Adjustment; also known as the E-Factor for the PGCC. The GCA is paid by sales customers (except for those that have returned to system supply within 12 months) and Choice customers who switched to Choice service from sales service within the past 12 months.
- STAS: State tax adjustment surcharge, which applies to all customers, and is a flat percentage of the non-purchased gas charges.
- PGDC E-Factor: The reconciliation charge related to the PGDC, which applies to the same customers as does the PGDC.
- CAF: The capacity assignment factor; which is the cost of transmission capacity (at 100 percent load factor) that is released to NGS Choice suppliers and which is then a credit to Choice customers. It applies only to Choice Rates RDS and SCD.
- Tennessee Refund: This reflects a credit from the Tennessee Pipeline that would normally be reflected as a credit to the PGDC. However, Columbia and OCA have agreed to use the residential portion of this credit to increase customer assistance to low-income customers. Thus, the Tennessee Refund is the non-residential portion of

the credit, which applies only non-residential customers. Columbia reports that it applies only to SGSS, SCD, and SGDS customers.

- CC: A charge for stranded capacity related to unbundling of gas supply, which applies to all small customers, but not larger customers. This item has been zero for several years.
- USP: The universal service charge, which applies to all residential customers (sales and Choice).
- GPC: Gas procurement cost charge; the new charge related to administrative costs of gas procurement, which applies to all sales customers.
- MFC: Merchant function charge, a percentage charge related to gas sales uncollectibles costs, which applies to Residential and Small C&I sales customers.

Q. How does the Company propose to consolidate these components into charges on customers' bills?

A. The Company proposes the following consolidation:

- System charge
- Distribution charge
- Gas supply charge (GSC): PGCC, GPC, MFC
- GCA
- Pass-through Charge: PGDC, PGDC E-Factor, CAF, CC, USP, and the Tennessee Refund.

In essence, Columbia has created a catch-all charge called a Pass-through, which includes gas supply costs/credits related to Choice customers, the universal service charge, and Rider CC. The Pass-through charge will be different for shopping and non-shopping customers.

Columbia proposes to report the PTC as the sum of the gas supply charge, the GCA, the GPC, the MFC, and a charge equal to the magnitude of the CAF credit. To its credit (and unlike some of the other Pennsylvania NGDCs), Columbia proposes to include the CAF credit in the PTC, even though it does not explicitly qualify under the Commission's PTC definition.

Q. Do you agree with this approach?

A. I agree that simplification is welcome and that the Company's proposal has a number of advantages. However, it also has a couple of disadvantages in terms of making it clear to customers what costs they can actually avoid by shopping.

First, customers will not be able to figure out how the PTC is derived. The PTC will include the reported GSC, and the GCA, but it will also be picking up some pieces from the Pass-through Charge that are not readily identifiable.

Second, the PTC reported for Small C&I sales service customers in Rate SGSS is the PTC relative to Choice service under Rate SCD, but not the PTC relative to transportation service under Rate SGDS.

Third, the Pass-through charge will change if a customer shifts from sales to Choice service, a result that is likely to be counter-intuitive to customers.

Q. Do you have an alternative suggestion?

A. I do, although I make this proposal as a recommendation for further study, rather than for immediate implementation. One of the difficulties associated with establishing a clear PTC for gas competition is that NGDCs provide *some* transmission and load balancing services to their shopping customers. Moreover, the services provided by the NGDC to shopping customers vary substantially from company to company, making a standard approach difficult. In general, however, NGDCs recover the costs for these services through a variety of charges and credits imposed directly on the shopping customers. It is therefore extremely difficult for a customer to figure out exactly which charges it would avoid by choosing to shop.

An alternative approach would be to change the philosophy from billing the shopping customer for load balancing services to billing the NGS for those services. In this model, NGS Choice suppliers would be billed for the load balancing service they get from

Columbia, which would basically include the PGDC, PGDC E-Factor, CAF credit, the Tennessee credit, and any cash working capital charge related to gas in storage.[39]

In this approach, the GSC would include all costs related to gas supply (PGCC, PGDC, MFC, and GPC), the GCA would include E-Factors for both commodity and demand, and the PTC would be simply the sum of the GSC and the GCA. This would be much easier for customers to understand. This approach also results in the same PTC for SGSS to SCD and SGSS to SGDS, further reducing confusion for small business customers.

Q. Are there disadvantages to this approach?

A. As I see it, the two major downsides to this alternative are (a) this will increase risk for Choice NGSs, who will now be directly responsible for load balancing costs and will need to recover those in their rates, and (b) the transition contract problem, where prices charged by Choice NGSs do not currently reflect load balancing costs and may be locked in by contract.

6.3 SGS/SGDS Customer Charges

Q. Please summarize the Company's proposals for the SGS/SGDS customer charges in this proceeding.

A. Under the Company's approved tariffs, the customer charge for the rate classes in the SGS/SGDS rate class group are bifurcated between smaller and larger customers, demarcated at 644 Dth per year. To put that figure in perspective, the average residential annual usage rate is 87 Dth per year, and the average SGS/SGDS annual usage is 367 Dth per year. Thus, a significant majority of SGS/SGDS customers are subject to the lower customer charge.

In this proceeding, Columbia proposes to increase the lower customer charge from \$20.18 per month to \$30.00 per month, an increase of nearly 49 percent. It similarly proposes to increase the higher customer charge from \$32.09 per month to \$45.00 per month, an increase of a little over 40 percent. In effect, the Company proposes a

[39] An advantage to charging NGSs for gas in storage is that NGSs may determine that their capital costs for gas in storage are lower than the long-term pre-tax weighted average cost of capital used by utilities, and would pursue opportunities to assume responsibility for those costs.

modestly larger increase to the customer charge than it does to the class as a whole (39 percent).

Q. In your view, how should the customer charge be established for small to medium general service classes like Columbia's SGS/SGDS class?

A. The simple answer for a homogeneous rate class is that the customer charge should be set to be consistent with the costs that are *classified* as customer-related in the COSS. In that way, each customer is charged for the costs that each new customer attracts to the class in the COSS.

The problem for general service classes is that customers come in a wide array of sizes, with a similarly wide array of customer costs. For example, as shown in Table IEc-4 above, the difference in meters costs between small and medium general service customers is at least a factor of ten. Size-based customer cost differences within the SGS/SGDS class also apply to services, regulators, industrial M&R equipment and large customer relations costs. It is therefore inaccurate and inequitable to impose the same customer charge on all customers within the SGS/SGDS class. If an *average* customer charge were to be applied to all customers within the class, small customers would implicitly be paying for the more expensive meters, regulators and services associated with large customers within the class, creating an inappropriate intra-class cross-subsidy.

It is this consideration which led to the adoption of the bifurcated customer charge. However, because the COSS does not separately track costs for customers above and below 644 Dth per year, the COSS cannot be used directly to set both customer charges.

Fortunately, this problem can be addressed by recognizing that the customer cost assigned to a smaller SGS/SGDS customer is exactly the same as the customer cost assigned to a typical residential customer. I therefore rely on customer costs assigned to residential customers to determine the appropriate level for the lower customer charge. The upper customer charge can then be set at a level to allow for reasonable recovery of the class' customer-related costs.

Q. How does the Company's proposal for the lower SGS/SGDS customer charge comport with residential customer costs in your COSSs?

A. My COSS analysis indicates that residential customer costs average about $19 per month under the IEc A&E COSS and $22 per month under the IEc ZI COSS.[40] In effect, when compared to the existing lower customer charge of $20.18 per month, the COSS analysis does not support any increase to the lower customer charge. I therefore recommend that the lower customer charge remain at its current level (or perhaps reduced to $20.00 per month for simplicity).

In contrast, the Company's proposed increase to the higher customer charge does not appear to be unreasonable, because the average customer costs for the SGS/SGDS class are well above that for the residential class ($28 and $31 respectively). I therefore take no exception to the proposed increase for the larger customer charge.

Q. Does this conclude your direct testimony?

A. Yes, it does.

[40] Note that these values include all customer-related costs in the COSS. I understand that Commission precedent supports the inclusion of only "direct" customer costs for setting the residential class customer charge. In my view, all customer-related costs should be included in the cost basis for non-residential customer charges, to minimize intra-class cross-subsidization. However, if the Commission determines that this policy should also apply to non-residential classes, my analysis indicates that the existing lower customer charge should be substantially reduced.

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 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.
- 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.
- 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.

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: 2005 TO 2010

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
NBEUB 2009-017	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	March 2010	New Brunswick Public Intervenor	Cost allocation, rate design
R-2009-2145441	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil	March 2010	Pennsylvania Office of Small Business Advocate	Unaccounted-for gas and retainage rates
R-2010-2150861	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2010	Pennsylvania Office of Small Business Advocate	Gas costs
P-2009-2099333	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	February 2010	Pennsylvania Office of Small Business Advocate	Purchase of receivables program
R-3708-2009	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2009	AQCIE/CIFQ	Post-patrimonial generation cost allocation, revenue allocation
M-2009-2123944, 2123945, 2123948, 2123950, 2123951	Pennsylvania Public Utility Commission	PECO, Duquesne Light, Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power	October, November 2009	Pennsylvania Office of Small Business Advocate	Smart Meter Cost Allocation and Rate Design
NBEUB 2009-006	New Brunswick Energy & Utilities Board	Enbridge Gas New Brunswick	September 2009	New Brunswick Public Intervenor	Development Period Criteria
M-2009-2092222, 2121952, 2112956, 2093218, 2093217, 2093215	Pennsylvania Public Utility Commission	Metropolitan Edison, Pennsylvania Electric, Penn Power, West Penn Power, Duquesne Light, PPL Electric	August 2009	Pennsylvania Office of Small Business Advocate	Energy efficiency and conservation programs, cost allocation, rate design
1604944; ID# 184	Alberta Utilities Commission	ATCO Gas	July 2009	Rate 13 Group	Cost allocation, rate design
R-2009-2105904, 909, 911	Pennsylvania Public Utility Commission	UGI Penn Natural Gas, UGI Central Penn Gas, UGI Utilities Inc. Gas Division	July 2009	Pennsylvania Office of Small Business Advocate	Gas supply procurement hedging, unaccounted-for gas, revenue sharing mechanisms
R-2009-2093219	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2009	Pennsylvania Office of Small Business Advocate	Revenue sharing mechanisms, retainage rate, gas procurement

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2005 TO 2010

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2008-2079660	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	May 2009	Pennsylvania Office of Small Business Advocate	Equity cost of capital, cost allocation, rate design
R-2008-2079675	Pennsylvania Public Utility Commission	UGI Central Penn Gas	May 2009	Pennsylvania Office of Small Business Advocate	Equity cost of capital, cost allocation, rate design
R-2008-2075250	Pennsylvania Public Utility Commission	T.W. Phillips Gas & Oil	April 2009	Pennsylvania Office of Small Business Advocate	Retainage rates
R-2009-2088076	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2009	Pennsylvania Office of Small Business Advocate	Gas procurement
R-2009-2083181	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2009	Pennsylvania Office of Small Business Advocate	Retainage rates, gas procurement
P-2008-2060309	Pennsylvania Public Utility Commission	PPL Electric Utilities	December 2008	Pennsylvania Office of Small Business Advocate	Default electric supply procurement
R-2008-2073938	Pennsylvania Public Utility Commission	Philadelphia Gas Works	December 2008	Pennsylvania Office of Small Business Advocate	Revenue requirement, financial cash flows, cost allocation, rate design.
P-2008-2044561	Pennsylvania Public Utility Commission	Pike County Light & Power	October 2008	Pennsylvania Office of Small Business Advocate	Electric default service procurement
R-3669-2008	Régie de l'Énergie, Québec	Hydro Québec TransÉnergie	October 2008	AQCIE/CIFQ	Transmission cost allocation.
R-3677-2008	Régie de l'Énergie, Québec	Hydro Québec Distribution	October 2008	AQCIE/CIFQ	Post-patrimonial supply cost allocation, revenue allocation, rate design.
R-3673-2008	Régie de l'Énergie, Québec	Hydro Québec Distribution	August 2008	AQCIE/CIFQ	Electric supply contract modifications.
1550487	Alberta Utilities Commission	ENMAX Power Corporation	July 2008	D410 Group	Formula-based (performance-based) ratemaking; ratepayer-supplied equity contributions.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2005 TO 2010

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-2008-2039417 et al.	Pennsylvania Public Utility Commission	UGI Utilities (Gas Division)	July 2008	Pennsylvania Office of Small Business Advocate	Design day demand forecast.
R-2008-2039284	Pennsylvania Public Utility Commission	UGI Penn Natural Gas	July 2008	Pennsylvania Office of Small Business Advocate	Revenue sharing, gas supply costs.
R-2008-2039634	Pennsylvania Public Utility Commission	PPL Gas Utilities	July 2008	Pennsylvania Office of Small Business Advocate	Lost and unaccounted-for gas, gas supply costs.
A-2008-2034045	Pennsylvania Public Utility Commission	UGI Utilities, PPL Gas Utilities	June 2008	Pennsylvania Office of Small Business Advocate	Public benefits of proposed sale.
R-2008-2011621	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2008	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
R-2008-2028039	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2008	Pennsylvania Office of Small Business Advocate	Gas supply cost functionalization; cost reconciliation method, sharing mechanisms.
R-3648-2007	Régie de l'Énergie, Québec	Hydro Québec Distribution	April 2008	AQCIE/CIFQ	Electric supply contract modifications.
R-2008-2021348	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2008	Pennsylvania Office of Small Business Advocate	Sharing mechanisms, gas supply contracts.
R-2008-2012502	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2008	Pennsylvania Office of Small Business Advocate	Transportation and sales customer rate design, design day forecasts.
R-2008-2013026	Pennsylvania Public Utility Commission	T.W. Phillips Gas and Oil	March 2008	Pennsylvania Office of Small Business Advocate	Rate design treatment of capacity release revenues.
P-00072342	Pennsylvania Public Utility Commission	West Penn Power d/b/a Allegheny Power	February 2008	Pennsylvania Office of Small Business Advocate	Default service electricity procurement, rate design, reconciliation.
2007-004	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Corporation	November 2007	New Brunswick Public Intervenor	Cost allocation, revenue allocation, rate design.

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-3644-2007	Régie de l'Énergie, Québec	Hydro Québec Distribution	October 2007	AQCIE/CIFQ	Cost allocation, revenue allocation, rate design.
P-00072305	Pennsylvania Public Utility Commission	Pennsylvania Power Corporation	July 2007	Pennsylvania Office of Small Business Advocate	Default electric service procurement.
R-00072334	Pennsylvania Public Utility Commission	UGI Penn Natural Gas, Inc.	July 2007	Pennsylvania Office of Small Business Advocate	Asset management arrangement, gas procurement.
R-00072333	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	July 2007	Pennsylvania Office of Small Business Advocate	Design day forecasting, gas procurement.
R-00072155	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	July 2007	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design, energy efficiency.
R-00049255 (Remand)	Pennsylvania Public Utility Commission	PPL Electric Utilities Corporation	May 2007	Pennsylvania Office of Small Business Advocate	Revenue allocation.
R-00072175	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania, Inc.	May 2007	Pennsylvania Office of Small Business Advocate	Gas procurement.
R-00072110	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2007	Pennsylvania Office of Small Business Advocate	Gas procurement, margin sharing mechanisms.
R-00061931	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2007	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, retail gas competition.
P-00072245	Pennsylvania Public Utility Commission	Pike County Light & Power Company	March 2007	Pennsylvania Office of Small Business Advocate	Default service procurement, rate design.
R-00072043	Pennsylvania Public Utility Commission	National Fuel Gas Distribution Company	March 2007	Pennsylvania Office of Small Business Advocate	Design day requirements.
C-20065942	Pennsylvania Public Utility Commission	Pike County Light & Power Company	November 2006	Pennsylvania Office of Small Business Advocate	Wholesale power procurement by provider of last resort.
R-3610-2006	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2006	AQCIE/CIFQ	Post-patrimonial generation cost allocation; cross-subsidization; rate design.

ROBERT D. KNECHT

EXPERT TESTIMONY SUBMITTED IN REGULATORY PROCEEDINGS: 2005 TO 2010

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
P-00052188	Pennsylvania Public Utility Commission	Pennsylvania Power Company	September 2006	Pennsylvania Office of Small Business Advocate	Affidavit: POLR rates, wholesale to retail.
R-00061493	Pennsylvania Public Utility Commission	National Fuel Gas Distribution Corporation	September 2006	Pennsylvania Office of Small Business Advocate	Rate of return, load forecasting, cost allocation, revenue allocation, rate design, revenue decoupling.
R-00061398	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	August 2006	Pennsylvania Office of Small Business Advocate	Cost allocation, revenue allocation, rate design.
R-00061365	Pennsylvania Public Utility Commission	PG Energy/Southern Union Company	July 2006	Pennsylvania Office of Small Business Advocate	Merger savings, cost allocation, revenue allocation, rate design.
R-00061519	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	July 2006	Pennsylvania Office of Small Business Advocate	Design day weather and throughput forecasts; gas supply hedging.
R-00061518	Pennsylvania Public Utility Commission	PG Energy/Southern Union Company	July 2006	Pennsylvania Office of Small Business Advocate	Design day weather and throughput forecasts; gas supply hedging.
A-125146	Pennsylvania Public Utility Commission	UGI Utilities, Inc., Southern Union Company	June 2006	Pennsylvania Office of Small Business Advocate	Public benefits of proposed sale of PG Energy to UGI; asset management agreement.
R-00061355	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2006	Pennsylvania Office of Small Business Advocate	Gas supply and hedging plan; procedural issues
R-00061296	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2006	Pennsylvania Office of Small Business Advocate	Gas procurement and procedural issues.
R-00061246	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2006	Pennsylvania Office of Small Business Advocate	Gas procurement; unaccounted for gas retention rates.
2005-002 Refiling	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	February 2006	New Brunswick Public Intervenor	Cost allocation, rate design.
P-00052188	Pennsylvania Public Utility Commission	Pennsylvania Power Company	December 2005	Pennsylvania Office of Small Business Advocate	Cost allocation and rate design for POLR supplies.
R-3579-2005	Régie de l'Énergie, Québec	Hydro Québec Distribution	November 2005	AQCIE/CIFQ	Generation cost allocation; cross-subsidization; revenue allocation.
2005-002	New Brunswick Board of Commissioners of Public Utilities	New Brunswick Power Distribution and Customer Service Company	August 2005	New Brunswick Public Intervenor	Cost allocation, rate design.

DOCKET #	REGULATOR	UTILITY	DATE	CLIENT	TOPICS
R-00050538	Pennsylvania Public Utility Commission	PG Energy	July 2005	Pennsylvania Office of Small Business Advocate	Gas procurement diversification.
R-00050540	Pennsylvania Public Utility Commission	PPL Gas Utilities Corporation	July 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, hedging, retention rates, sharing mechanism.
R-00050340	Pennsylvania Public Utility Commission	Columbia Gas of Pennsylvania	May 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, hedging and diversification.
R-3563-2005	Régie de l'Énergie, Québec	Hydro Québec Distribution	April 2005	AQCIE/CIFQ	Generation cost allocation; industrial demand response.
R-00050264	Pennsylvania Public Utility Commission	Philadelphia Gas Works	April 2005	Pennsylvania Office of Small Business Advocate	Gas procurement, risk hedging, financing costs in the gas cost rate.
R-00050216	Pennsylvania Public Utility Commission	National Fuel Gas Distribution	March 2005	Pennsylvania Office of Small Business Advocate	Gas supply procurement and forward pricing policies.
EB-2004-0542	Ontario Energy Board	Union Gas Limited	March 2005	Tribute Resources Inc.	Cost allocation and rate design for service to embedded storage pools.
R-00049884	Pennsylvania Public Utility Commission	Pike County Light and Power (Gas Service)	January 2005	Pennsylvania Office of Small Business Advocate	Fair rate of return, cost allocation, class revenue assignment.

March 2010

EXHIBIT IEc-2

IEc WORKPAPER LISTING

WP1 CPA 2012 CD COSS.xlsx: RDK replication of Columbia CD COSS.

WP2 CPA 2012 P&A COSS.xlsx: RDK replication of Columbia P&A COSS

WP3 CPA 2012 IEc ZI COSS.xlsx: IEc Zero-Intercept COSS

WP4 CPA 2012 IEc A&E COSS.xlsx: IEc A&E COSS

WP5 CPA Revenue Proof.xlsx: IEc replication of Columbia FTY ending May 2014 proof of revenues.

WP6 Large Customer Peaks CONFIDENTIAL.xlsx: IEc analysis of LGS, SDS, and LDS peak demands. Note that this file contains confidential information.

WP7 SGS-SGDS Monthly Customer Loads.xlsx: 2011 Monthly loads by customer

WP8 RoE Comparions.xlsx: RDK regulated RoE comparisons

WP9 Meter Tabulations.xlsx: Review of meter cost information from Columbia

WP10 GPC Comparions.xlsx: Comparison of GPC cost bases by NGDC.

IEc Workpapers are available to any party upon request of OSBA.

EXHIBIT IEc-3

REFERENCED INTERROGATORY RESPONSES

(in numerical order)

OSBA-I-11

OSBA-I-12

OSBA-I-14

OSBA-I-21

OSBA-I-23

OSBA-I-25

OSBA-I-26

OSBA-I-28

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Small Business Advocate - Set I

Question No. OSBA I –011

Reference Exhibit JES-3:

a. Reference page 6, rows 37 and 47: Please reconcile the difference between the reported 2-inch main footage between the referenced rows. Is it correct to interpret this difference to mean that the vast majority of Columbia's 2-inch mains are not operated at "low pressure?"

b. Reference page 6, row 48: Please explain why Columbia apparently operates a significant percentage of its mains of over 2-inches in diameter at low pressure. Please include in your explanation an indication as to whether these assets were designed and installed with the intent of operating at low pressure.

c. Reference page 6, line 48: For the low pressure mains over 2 inches in diameter, please provide a table showing the footage by main diameter and composition (plastic, steel, etc.). Please also provide an estimate of the hourly gas flow rate associated with the operation of each size main at low pressure, for representative pipe lengths.

d. Reference page 6, rows 41 and 51: Please reconcile the difference in total mains footage between the referenced rows.

e. Please explain how Columbia determined that zero customers in the LGS, SDS, LDS and MDS classes rely on either 2-inch mains or low-pressure mains for distribution service.

f. Please specify the range of operating pressures that Columbia uses for its 2-inch mains, and an estimate (or reasonable range) of the hourly gas flow rate at each pressure, for representative pipe lengths.

g. Please specify the number of customers, peak demand and annual throughput for those customers in both the RS/RDS and SGS/SGDS classes who do not take service from either low-pressure or 2-inch mains, if any.

h. Please specify the number of customers, peak demand and annual throughput for those customers in both the RS/RDS and SGS/SGDS classes who are served only from 2-inch or low pressure mains, and who are not served downstream through from any higher-pressure mains, if any.

i. Reference page 6, rows 3 and 7: Please reconcile the differences between reported total mains plant. Please specify the differences related to mains additions, non-pipe assets (please detail) and other factors contributing to the difference.

j. Reference page 6: Please explain why low pressure mains in excess of 2-inches in diameter are allocated based on number of customers, rather than a minimum system cost allocation method.

k. Reference page 6: Please explain why Columbia classifies non-low-pressure mains in excess of 2-inches in diameter based on a system-wide minimum system calculation, rather than a minimum system calculation that applies only to the larger higher-pressure mains.

l. Reference page 1 (second paragraph) and page 6, line 8: Please explain why it is reasonable to use the GIS *footage* percentage of low-pressure mains as representative of the *cost* percentage for those mains.

Response:

a. Yes, the majority of the company's 2-inch main is operated above "low pressure".

b. Columbia operates a pipeline system that has been built over many decades. While low pressure systems are not the preferred option today, they were the predominate design for many decades, and Columbia continues to operate its low pressure systems as designed. In low pressure systems, larger diameter pipes are needed to provide reliable service to customers over a large area. These larger diameter pipes are needed to carry the aggregate volume of gas being used by customers on that system and still have sufficient pressure upon delivery to the customer.

c. OSBA I – 011- Attachment A to this response provides the footage of all low pressure pipe by diameter and composition as of September 15, 2012, Please note that upon subsequent review, certain footage data was found to be incorrect and the corrected data is provided. There is a minimal change in the allocation percentage.

   OSBA I – 011 - Attachment B to this response provides average flow data by pipe size.

d. The footage shown on line 41 totaling 39,318,859 is based on the company's plant accounting records as of May 31, 2012, the end of the historic test year. The footage shown on line 51 is from the company's Geographic Information System as of September 15, 2012 which was the latest date available at the time of preparing the allocation.

e. Through discussions with Company personnel, it was concluded that proper engineering design generally would not support serving the requirements of larger volume customers off of 2" mains and low-pressure mains. However, detailed information not available at the time of filing shows that there are unique circumstances where a small number of LGS and SDS customers are served by either 2-inch mains or low-pressure mains for distribution service.

   Specifically, out of 46 LGS accounts (64,380 – 108,300 therms), there are 5 LGS accounts that are served off a low pressure system and 11 are served off a 2" main.

   Out of 31 LGS accounts (107,300 – 536,490 therms), there are 4 LGS accounts that are served off a low pressure system and 1 served off a 2" main.

   The one LGS account (536,489 – 1,072,989 therms) was neither served off a low pressure system or a 2" main.

   Out of 183 SDS accounts (64,380 – 107,300 therms), there are 4 accounts that are served off a low pressure system and 15 are served off a 2" main.

Out of 234 SDS accounts (107,300 – 536,490 therms), there are 3 accounts that are served off a low pressure system and 16 are served off a 2" main.

Out of 39 LDS accounts (536,500 – 1,073,000 therms), there are no accounts that are served off either a low pressure system or a 2-inch main.

MLS facilities were directly assigned and provided in response to OSBA I - 020.

The most common circumstance where LGS and SDS classes rely on either 2-inch mains or low-pressure mains for distribution service is where multiple premises are combined under one customer account. An example is a college campus where multiple buildings are combined under one account for billing.

f. See OSBA I – 011 - Attachment C to this response.

g. There were 49,427 RS/RDS customers with throughput of 4,049,218.2 Dth and 7,115 SGS/SGDS customers with throughput of 4,469,708.7 Dth during the 12 months ending May 2012 who do not take service from either low-pressure or 2-inch mains.

   The 2013/2014 Design Day Demand for customers who do not take service from either low-pressure or 2-inch mains, for the RS/RDS rate class is expected to be 66,500 Dth and for the SGS/SGDS rate class is expected to be 60,700 Dth (60,000 Dth commercial and 700 Dth industrial).

   If individual customer's load was the only factor in the determination of both the size and pressure of the main to serve the customer all of the RS/RDS or SGS/SGDS customers would be served off either a low pressure or 2-inch main. However, distance from the transmission line and number of customers served off the distribution line also plays a role in whether an RS/RDS or SGS/SGDS customer is served off supply lines at higher pressures and larger diameter pipe.

   Since the exact number of RS/RDS or SGS/SGDS customers that are served off higher pressure or greater than 2-inch Mains was not clear at the time of filing this case, CPA chose to allocate the cost of the higher pressure and greater than 2-inch mains using traditional allocation methods that the company has traditionally supported in its rate case filings in Pennsylvania.

h. There were 326,746 RS/RDS customers with throughput of 24,682,828.6 Dth and 29,839 SGS/SGDS customers with throughput of 7,331,196.8 Dth during the 12 months ending May 2012 who are served only from 2-inch or low pressure mains.

The 2013/2014 Design Day Demand for customers who do take service from either low-pressure or 2-inch mains, for the RS/RDS rate class is expected to be 410,600 Dth and for the SGS/SGDS rate class is expected to be 117,300 Dth (117,100 Dth commercial and 200 Dth industrial).

Although it is known that these customers were directly served off either a 2-inch or low pressure main, it is not readily known how many of these mains are downstream from a higher-pressure distribution main. A detailed analysis of CPA's distribution system would have to be performed on a customer by customer basis to identify upstream pipe that feeds the 2-inch or low pressure main the customer is served off of.

However, from discussions with company engineers, it is the rare exception that low pressure system is downstream (supplied by) a higher pressure distribution system and that the vast majority of 2 inch main is also supplied by larger diameter mains. The normal throughout CPA's distribution system is that low pressure system are supplied from a higher pressure distribution main and 2 inch mains are fed from a larger distribution mains.

Additionally, in the case of 2-inch or low pressure mains CPA does know and has now confirmed through its response to this data request (see response to e. above) that with the exception of 16 customers, all low pressure pipe serves either the RS/RDS or SGS/SGDS rate classes and with the exception of 44 customers, all 2-inch pipe directly serves either the RS/RDS or SGS/SGDS rate classes.

Consistent with cost-causation principles, the allocated cost of service study employs direct allocation of cost to the extent the costs are known and measurable. Direct allocation refers to the specific identification or isolation of the cost of service to a specific activity or classification of cost.

After the direct allocation of 2-inch and low pressure mains to the RS/RDS and SGS/SGDS rate classes, the remaining allocation between the RS/RDS and SGS/SGDS rate classes were based off traditional allocation methods that the company has supported in its previous rate case filings in Pennsylvania.

i. Line 3 is the total of the company's main investment as of June 30, 2014, the end of the fully forecasted rate year, included in the various 376 gas plant accounts as shown Exhibit 111, Schedules 1 & 2, lines 18 through 23. The amount on line 7 is the total value of the pipe included in gas plant accounts 376-101-1000 (gas plant in service) as of the end of the historic test year May 31, 2012.[1] As shown in Exhibit No. 8, and continuing through to Exhibit No. 108 the primary difference is projected additions and retirements from the end of the historic test year to the fully forecasted rate year.

j. A minimum size main is the minimum cost main necessary to connect the customer to the system and thus affords the customer on opportunity to take service.

2-inch mains are the minimum size main CPA installs, with rare exception to connect the customer to the system. CPA's Customer/Demand study in this case and in previous cases filed before the Pennsylvania Public Utility Commission uses 2-inch mains as the basis of the customer component of mains. The customer component of mains in those studies is allocated on a customer ratio to the rate classes.

In addition to the 2-inch main, the low pressure mains also constitute the definition of a minimum size main serving primarily the RS/RDS and SGS/SGDS rate classes and therefore CPA allocated on a customer ratio to the rate classes.

There could be merit in allocating the low pressure mains in excess of 2-inch in diameter based off the minimum system cost allocation method in that it is assumed in a minimum system allocation study that pipe greater than 2-inches in diameter is designed for demand in excess of average demand in addition to average demand.

k. As stated in response h. above, consistent with cost-causation principles, the allocated cost of service study employs direct allocation of cost to the extent the costs are known and measurable. To the extent costs cannot be directly allocated, these costs are allocated using accepted allocation methods.

In addition to LGS/SDS/LDS/MLDS directly being served off non-low-pressure mains in excess of 2-inches, some RS/RDS and SGS/SGDS customers are directly served off non-low-pressure mains in excess of 2-inches (see response to g. above) and more importantly a majority of

[1] The total account value is $676,162,024 as shown in Exhibit No. 8, Schedule 1, page 1 of 2.

RS/RDS and SGS/SGDS customers are indirectly served off non-low-pressure supply mains in excess of 2-inches.

Because CPA non-low-pressure mains in excess of 2-inches serve all classes of customers their cost should be allocated to all classes of customers.

I. The use of average costs is an acceptable technique in the public utility industry when specific cost information is not available. Furthermore, Columbia's distribution system was installed over many years at varying costs. As a result, it is reasonable to assume that the cost of the low pressure pipe has similar cost as the remaining pipe.

Nominal Diameter	Plastic	Steel	Cast Iron	Wrought Iron	Fittings	Other
Unknown		618			5,643	16,463
0.25	255					
0.375	2					
0.5	110					
0.75	336	164				
1	8,241	5,897			39	
1.125	1,233					
1.25	71,577	16,357			10	
1.5	541	6,284				
2	1,232,675	988,957	27	2,132	223	82
2.5		4,127				
3	833,151	622,374	17,821	10,159	104	
3.188		155				
3.5		7,878				
4	1,879,670	3,243,790	134,325	10,920	364	1
4.25		798				
4.5		3,417				
4.875		14,561		1,976		
5	73	27,130		380		
5.125		25				
5.1875		116				
5.188		16,166				
5.25		612				
5.5		295				
5.625		22,955		1,936	6	
5.875		36				
6	685,115	1,680,226	54,772	5,308	635	50
6.25		11,748				
6.625	17	106,966			11	
8	214,823	305,600	14,559	4,677	139	
10	241	169,749	2,202	2,076	24	
12		36,992	867	2,354	3	
14		450				
16		19,735			1	
20		1,642				
TOTALS	4,928,060	7,315,820	224,573	41,918	7,202	16,596

Revised numbers	**Footage**	**%**
Low Pressure 2" gas Mains	2,224,096	5.66%
Low Pressure greater than 2" gas Mins	10,176,303	25.89%
Low Pressure less than 2" gas mains	133,770	0.34%
Total Low Pressure	12,534,169	31.88%
Non Low Pressure	26,779,719	68.12%
Total CPA Gas Mains	39,313,888	100.00%

Nominal Pipe Size	Group	Average Of Flow (mcf)
<2	<=100	0.16
<2	100<L<=500	0.11
<2	500<L<=1,000	0.02
2	<=100	0.42
2	100<L<=500	0.30
2	500<L<=1,000	0.33
2	1,000<L<=1,500	0.38
2	1,500<L<=2,000	0.33
2	L>2,000	0.16
2.5	<=100	0.70
2.5	100<L<=500	0.60
3	<=100	1.02
3	100<L<=500	0.85
3	500<L<=1,000	0.82
3	1,000<L<=1,500	1.09
3	1,500<L<=2,000	0.96
4	<=100	1.84
4	100<L<=500	1.59
4	500<L<=1,000	1.55
4	1,000<L<=1,500	1.46
4	1,500<L<=2,000	1.33
4	L>2,000	0.77
4.25	<=100	0.37
4.25	100<L<=500	1.34
4.5	<=100	7.55
4.5	100<L<=500	2.99
4.875	500<L<=1,000	0.80
5	<=100	2.94
5	100<L<=500	2.57
5	500<L<=1,000	3.80
5	1,000<L<=1,500	2.91
5	L>2,000	1.35
5.1875	<=100	4.88
5.1875	100<L<=500	5.09
5.1875	500<L<=1,000	7.47
5.25	<=100	1.99
5.25	100<L<=500	1.73
5.625	<=100	5.98
5.625	100<L<=500	3.61
5.625	500<L<=1,000	3.85
5.625	1,000<L<=1,500	10.53
6	<=100	5.01
6	100<L<=500	4.61
6	500<L<=1,000	3.75
6	1,000<L<=1,500	3.67
6	1,500<L<=2,000	2.37
6	L>2,000	1.40
6.25	<=100	2.77
6.25	100<L<=500	1.97
6.25	500<L<=1,000	3.54
6.625	<=100	4.99
6.625	100<L<=500	4.37
6.625	500<L<=1,000	4.48
6.625	1,000<L<=1,500	3.63
6.625	1,500<L<=2,000	3.17
8	<=100	11.57
8	100<L<=500	11.46
8	500<L<=1,000	9.53
8	1,000<L<=1,500	9.15
10	<=100	17.04
10	100<L<=500	20.34
10	500<L<=1,000	18.18
10	1,000<L<=1,500	14.58
12	<=100	29.02
12	100<L<=500	29.42
12	500<L<=1,000	20.79
14	<=100	51.28
14	100<L<=500	51.28
16	<=100	37.36
16	100<L<=500	50.40
16	500<L<=1,000	76.02
20	<=100	65.75
20	100<L<=500	72.93
24	<=100	98.75

Nominal Pipe Size	Pressure Code	[illegible] Group	Average Of Flow (mcf)
2	IP	<=100	1.32
2	IP	100<L<=500	0.96
2	IP	500<L<=1,000	0.94
2	IP	1,000<L<=1,500	0.89
2	IP	1,500<L<=2,000	0.88
2	IP	L>2,000	0.93
2	MP	<=100	2.48
2	MP	100<L<=500	1.72
2	MP	500<L<=1,000	1.46
2	MP	1,000<L<=1,500	1.54
2	MP	1,500<L<=2,000	1.70
2	MP	L>2,000	1.81
2	HP	<=100	8.86
2	HP	100<L<=500	4.37
2	HP	500<L<=1,000	8.92
2	HP	1,000<L<=1,500	9.56
2	HP	1,500<L<=2,000	11.71
2	HP	L>2,000	11.91

IP = 1 to 10 psig
MP = > 10 psig to 60 psig
HP > 60 psig

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Small Business Advocate - Set I

Question No. OSBA I –012:

Reference Exhibit 111, Schedule 1, pages 12 and 13, allocation factors:

a. Regarding Factor 25, were SCD volumes inadvertently excluded from the SGS/SGDS sales plus Choice total? Please explain any negative response.

b. Regarding Factor 1, were Rate NSS peak demands inadvertently included in the SGS/SGDS class (in contrast to the throughput and revenue allocators where NSS is include with MDS)? Please explain any negative response.

Response:

a. Yes. SCD volume was inadvertently excluded in the Factor 25 calculation. The correction will increase slightly the allocation percentage to SGS/SGDS and away from the RS/RDS, LGS and MDS.

b. No. The volume shown under SGS/SGDS for NSS COMM relates to SGDS customers that were taking service under Columbia's Negotiate Sales Service ("NSS"). At the time of developing the forecast, Columbia was providing firm service to these customers under NSS. They are no longer taking service under NSS, but Columbia still has the firm commitment. The inclusion under SGS/SGDS is proper.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Small Business Advocate - Set I

Question No. OSBA I –014:

Reference Factor 16:

a. Please provide a full reconciliation for the difference between the $24,235,911 in directly assigned meters costs used to develop Factor 16 and the test year meters plant cost of $34,301,875 in plant, $20,548,041 in AMR, and $35,468,816 in meters installations.

b. In MS Excel electronic format, please provide a version of the workpaper for Factor 16 which shows the number of meters in each of the 92 customer categories shown.

c. Please describe the specific nature of the costs included in account 381.10 AMR, and explain how they differ from other meters costs.

d. Please provide all evidence relied upon for concluding that AMR and meter installations costs are proportional to Factor 16.

e. Please provide all evidence that house regulators and house regulator installation costs are proportional to Factor 16.

f. For each of the past five years, for each rate class, please provide a MS Excel dataset showing each meter installation or replacement, with the following plaint investment information:

i. Meters plant cost;

ii. Meters installation cost;

iii. AMR plant cost;

iv. Regulator plant cost;

v. Regulator installation cost.

g. Please explain why the meters plant cost per customer for Rate LGS is much higher than that for Rate classes SDS, LDS and MDS, despite the fact that average throughput per LGS customer is much lower than for these other rate classes.

Response:

a. Factor No. 16 is based on the historic test year meter investment included in Gas Plant Account 381. The balance as of May 2012 totals $31,834,475. The amount is presented by meter size in response to GASCOS-07. This amount is the beginning balance in Exhibit No 108, Schedule No. 1, Page 2 of 23, line 42. Projected additions and retirements through the end of the rate year are added to this amount to arrive at projected June 30, 2014 balance of $34,301,875 as shown in Exhibit No. 108, Schedule 1, Page 2, Page 13 of 13.

In developing Factor 16, the average costs of the 4 meter sizes, which is based on the May 2012 booked amounts, are applied to the number of active meters under each rate schedule as identified in the company's billing system. The calculation is presented in response to GASCOS-19, Attachment 4.

b. See Attachment A to this response for a detail listing of the meters by size, by rate schedule. It also calculates the costs based on the average unit cost from the company's plant records (see page 17). Attachment B to this response extracts the data and summarizes the meter costs by rate schedule and calculates Factor No. 16.

c. Gas Plant Account 381.10 contains the cost of the Automatic Meter Reading device and the cost to install.

d. The Automatic Meter Reading devices have different prices based on the size of the meter. Because of price differential based on size of the meter, the company relied on Factor No. 16 to allocate this account. No additional study was prepared.

e. The company, when preparing Allocated Cost of Service Studies, has historically assigned regulator and regulator installations based on its meter analysis based on the assumption that these costs follow meter investment. No separate study has been prepared.

f. As noted above, the company's plant accounting system does not maintain meter and related costs by rate schedule. In developing Factor No. 16, the average costs of the 4 meters sizes, developed from the accounting records, were applied to the number of meters, by rate schedule as maintained in the company's billing records. Attachment C to this response presents the additions and retirement of the requested plant accounts for the historic test year and the four previous years.

g. From the company's billing system, appears the LGS class has a higher percentage of multi-metered/combined accounts resulting in higher meter investment assigned to that class.

	Rate Schedule		
	LGS	SDS	LDS
Customers	79	416	91
Meters	158	485	146
Ratio	2.00000	1.16587	1.60440

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Small Business Advocate - Set I

Question No. OSBA I – 021:

Reference Columbia Statement No. 9, page 7, lines 1 to 5:

a. Please provide calculations supporting the referenced statement. As part of your response, please specify the operating pressure, gas specific gravity, and main length assumed for this statement, and the basis therefor.

b. Please reconcile this statement with the information used to derive Factor 15 which indicates that a majority of LGSS and SDS customers, and a significant percentage of LDS customers, have service lines of "under 3 inches" in diameter.

c. Please specify the number of LGS, SDS, LDS and MDS customers with service lines at or below 2 inches in diameter.

Response:

a. There was no separate calculation. A number of factors such as the customer's peak hourly demand, its location on the system, number of other customers on the system, etc. influences the size of main in which a customer is served. The statement was based on the assumption that customers with annual throughput greater than 64,400 therms would be predominantly served off a main with a diameter greater than 2 inches.

In preparation of the company's response to OSBA I-011(e) a computer program was written to identify what size and pressure main CPA's LGS, SDS, and LDS customers are served off of and to confirm the assumption. The results confirmed that, in fact, no LDS customers rely on either 2-inch or low pressure mains for distribution service. There were, however, a few LGS and SDS accounts that do rely on either 2-inch or low pressure mains for distribution service primarily as a result of combined billing where multiple premises are combined under one customer account for billing purposes.

b. In preparation of this response the company analyzed the raw data that factor 15 was developed from and discovered a computer program error. In the instances where a customer's meter was changed out within the test year, the program counted the customer's service line twice for use in developing factor 15. The computer program has been corrected and OSBA I-021 Attachment A to this response shows a corrected factor 15 as a result.

As for the reason why there still a percentage of LGSS, SDS, and LDS customers who have service lines of "under 3 inches" in diameter there are two primary reasons:

1) There were a few LGS and SDS accounts that do rely on either 2-inch or low pressure mains for distribution service.

2) Some LGS, SDS or LDS accounts are a combined billing of multiple premises with much lower throughput. Meter readings at these premises are combined under one customer account for billing purposes. A college or university is an example of a combined billing account.

c. LGSS – there are 60 customers that have 94 services lines at or below 2 inches in diameter.

SDS – there are 120 customers that have 123 services lines at or below 2 inches in diameter.

LDS – there are 26 customers that have 47 services lines at or below 2 inches in diameter.

MLDS – there is 1 customer that has 1 service line at or below 2 inches in diameter.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 15
DIRECT ASSIGNMENT - SERVICES

LINE NO.		SERVICE INVESTMENT QUERY	
1	Less Than 3 Inches	295,690,402	99.19%
2	3 Inches and Over	2,388,367	0.81%
3	TOTAL	298,078,770	100.00%

LINE NO.		RS/RDS RSS Residential	RS/RDS CAP Cust Assist Prgm	RS/RDS RDS Residential-D	RS/RDS RDGSS Res Distributed Gen Sales	RS/RDS RDGDS Res Distributed Gen Dist	RS/RDS TOTAL	SGS/SGDS SGSS Small General	SGS/SGDS NSS [illegible]	SGS/SGDS SCD Small Comm-D	SGS/SGDS SGDS Small General-D	SGS/SGDS TOTAL	LGS LGSS Large General	SDS SDS Small Distribution	LDS LDS Large Distribution	Total before Main Line/SS	Main Line MLSS Main Line	Main Line MLDS Main Line-D	Other SS Standby	Total
4	Less Than 3 Inches Weighted Customers	244,729	18,548	79,180	23	6	342,486	20,672	11	6,451	1,961	29,085	110	175	92	371,958	0	4	0	371,882
5	Avg. Unit Cost	$ 612.82	$ 612.82	$ 612.82	$ 612.82	$ 612.82	$ 612.82	$ 612.82	$ 612.82	$ 612.82	$ 612.82	$ 612.82	$ 612.82	$ 612.82	$ 612.82		$ 612.82	$ 612.82	$ 612.82	$ 612.82
6	Less Than 3 Inches Weighted $	$ 149,852,461	$ 11,357,511	$ 48,489,458	$ 14,088	$ 8,424	$ 209,711,878	$ 12,657,879	$ 6,736	$ 3,950,076	$ 1,200,780	$ 17,815,430	$ 67,355	$ 107,196	$ 56,333	$ 227,757,822	$ -	$ 2,449	$ -	$ 227,759,772
7	3 Inches and Over Weighted Customers	79	7	19	0	0	105	375	6	42	233	656	28	116	66	973	0	4	0	977
8	Avg. Unit Cost	$ 873.90	$ 873.90	$ 873.90	$ 873.90	$ 873.90	$ 873.90	$ 873.90	$ 873.90	$ 873.90	$ 873.90	$ 873.90	$ 873.90	$ 873.90	$ 873.90		$ 873.90	$ 873.90	$ 873.90	$ 873.90
9	Over 3 Inches Weighted $	$ 69,038	$ 6,117	$ 16,604	$ -	$ -	$ 91,760	$ 327,713	$ 5,243	$ 36,704	$ 203,615	$ 573,278	$ 24,469	$ 101,372	$ 58,425	$ 850,804	$ -	$ 3,496	$ -	$ 853,800
10	Total Weighted Dollars	$ 149,921,499	$ 11,963,428	$ 48,500,302	$ 14,088	$ 8,674	$ 209,803,788	$ 12,985,592	$ 11,979	$ 3,985,780	$ 1,404,379	$ 18,388,728	$ 91,824	$ 208,528	$ 115,758	$ 228,607,626	$ -	$ 5,945	$ -	$ 228,613,572

LINE NO.		RS/RDS	SGS/SGDS	LGS	SDS	LDS	TOTAL
11	Less Than 3 Inches Percentages	92.06%	7.89%	0.03%	0.06%	0.03%	100.00%
12	3 Inches and Over Percentages	10.79%	67.42%	2.88%	11.92%	6.99%	100.00%
13	ALLOCATOR #16	91.77%	8.04%	0.04%	0.09%	0.05%	100.00%

QUERY

LINE NO.	LESS THAN 3" PU#	Description	Size Code	Book Cost	3" AND OVER PU#	Description	Size Code	Book Cost	
1	6551	Main/Meter	06	437	6551	Main/Meter	21	208,345	
2	6551	Main/Meter	08	3,016,982	6552	Main/Curb	21	471,193	
3	6551	Main/Meter	10	528,918	6554	Curb/Meter	21	73,341	
4	6551	Main/Meter	12	7,131,506	6555	Curb/Meter	21	91,917	
5	6551	Main/Meter	16	40,238	6558	Main/Meter	21	22,667	817,362
6	6551	Main/Meter	18	3,542	6552	Main/Curb	23	2,636	
7	6551	Main/Meter	96	4,287,621	6553	Curb/Meter	23	2,836	5,672
8	6552	Main/Curb	06	13,118	6551	Main/Meter	25	1,423	
9	6552	Main/Curb	08	69,137	6552	Main/Curb	26	676	2,000
10	6552	Main/Curb	10	1,287,626	6561	Main/Meter	26	334,294	
11	6552	Main/Curb	12	-	6562	Main/Curb	26	673,530	
12	6552	Main/Curb	16	3,432	6564	Curb/Meter	26	94,637	
13	6552	Main/Curb	96	217,646,172	6569	Curb/Meter	26	104,683	1,206,967
14	6552	Main/Curb	98	1,896	6561	Main/Meter	27	4,338	
15	6554	Curb/Meter	08	206,106	6598	Main/Meter	27	1,642	5,980
16	6554	Curb/Meter	10	91,037	6551	Main/Meter	30	616	616
17	6554	Curb/Meter	12	140,227	6551	Main/Meter	36	119,829	
18	6554	Curb/Meter	18	1,310	6552	Main/Curb	36	58,115	
19	6554	Curb/Meter	16	66,275	6554	Curb/Meter	36	2,444	
20	6554	Curb/Meter	96	282,201	6595	Curb/Meter	36	20,436	
21	6558	Curb/Meter	06	9,782	6558	Main/Meter	36	12,236	213,059
22	6558	Curb/Meter	08	264,602	6551	Main/Meter	37	2,050	2,050
23	6558	Curb/Meter	10	123,390	6551	Main/Meter	40	17,622	
24	6558	Curb/Meter	12	36,849	6552	Main/Curb	40	24,644	42,266
25	6558	Curb/Meter	16	187,691	6551	Main/Meter	42	683	683
26	6558	Curb/Meter	96	40,906,081	6561	Main/Meter	48	112	112
27	6559	Main/Meter	96	17,736,138	6551	Main/Meter	60	742	742
28	6559	Main/Meter	96	78,848	6551	Main/Meter	58	158	158
29			Total Under 3"	295,690,402		Total Over 3"		2,388,367	

1/ Does not tie directly to Account 380, due to inclusion of unreported pipe.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Small Business Advocate - Set I

Question No. OSBA I – 023:

Reference Columbia Exhibit JES-2, page 5, and Factor 17:

a. Please indicate whether the methodology for allocating industrial M&R equipment has changed since the Company's last base rates case. If so, please explain.

b. Please provide the evidence relied upon for assuming that each M&R station has the same cost.

c. Please provide a version of the workpaper for Factor 17 showing the book cost for each of the 30 rate codes reported.

d. Please provide the number of Rate MDS M&R station associated with the $122,846 in directly assigned plant.

Response:

a. The methodology for allocating industrial M&R equipment is the same in both this case and the previous case.

b. The cost of the industrial M&R equipment is not the same. Columbia's plant accounting system contains the book cost, and does not identify the rate schedule for each station. However, the Company's billing system does show the rate schedule assigned to each Industrial M&R station. A summary by rate schedule of the Industrial M&R stations from the billing system is developed. The average price of the Industrial M&R stations is calculated and applied to the number of stations under each rate schedule grouping. The average costs for each rate schedule grouping is used to develop Factor No. 17. The Company has consistently used this method in this jurisdiction and others, and believes it is a reasonable method to allocate the cost of Account 385.

c. As explained above the rate class is not assigned to the stations in the plant accounting system, and therefore not available. Attachment A to this response shows the calculation described above.

d. There are 6 Industrial M&R stations associated with the $122,846 of directly assigned plant.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 17
DIRECT ASSIGNMENT - INDUSTRIAL MEASURING & REGULATING STATIONS [1]

LINE NO.	RATE CODE	SGS/SGDS	LGS	SDS	LDS	TOTAL
1	LG1		29			
2	LG2		28			
3	LG3		1			
4	LIS/8__				27	
5	LIS/TI8				47	
6	LIS/TIB				1	
7	LIS/TIF			76		
8	LIS/TIG			12		
9	NS2	1				
10	NS5	2				
11	NSC	1				
12	NSD	3				
13	NSE	2				
14	NSF	1				
15	NSG	2				
16	NSH	2				
17	NSI	1				
18	NSQ	1				
19	NSR	1				
20	NST	1				
21	SC2	5				
22	SCC	5				
23	SG2	157				
24	SG3	8				
25	SG4	22				
26	SGS	56				
27	SGT	173				
28	SIS/8__	11				
29	SIS/TI4			103		
30	SIS/TIB	200				
31	TOTAL STATIONS	655	58	191	75	979
32	Dollars (Line 31 X Line 38 - Cost per Station)	4,490,787	397,657	1,309,527	514,212	6,712,184
33	**ALLOCATOR #17**	66.91%	5.92%	19.51%	7.66%	

34	Total Account 385 (101 & 106):	5,355,556
35	Total Account 385.10 (101 & 106):	1,356,628
36	Total Account 385/385.10	6,712,184
37	Total M&R Stations:	979
38	Cost per Station (Ln. 36/Ln. 37)	$ 6,856.16

[1] Excludes Direct Assignment

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Small Business Advocate - Set I

Question No. OSBA I – 025:

Reference Exhibit JES-2, page 7, Factor 21:

a. Please explain how a customer qualifies to be supported by the Large Customer Relations Group. As part of your response, please explain why all of the SDS customers and three of the LDS are not supported by the Large Customer Relations Group.

Response:

The Large Customer Relations (LCR) group uses general guidelines to determine which customers to support as major account customers. A customer being managed by the LCR group will typically be of the LDS class in terms of their annual gas requirements. However, smaller volume customers are supported as major accounts if their competitive situation warrants it or if gas is used for industrial processing. Likewise, a larger annual volumetric user may not be supported as a major account if there is little or no industrial processing in their use. In the referenced ACOS study, the SDS customers supported by the LCR group were inadvertently assigned to the LGS class. LCR supports 39 SDS customers and 2 LGS customers.

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Small Business Advocate - Set I

Question No. OSBA I – 026:

Reference Factor 7:

a. Please provide a five-year history of actual uncollectibles by rate class.

b. To the extent Columbia cannot identify uncollectibles by class, please explain how Columbia can write off a receivable to bad debt without knowing the specific customer associated with the write-off. For example, how can Columbia be certain that a particular aging receivable for a specific customer has been properly written off, or that it has not been written off more than once?

c. Please provide a detailed receivables aging report as of September 30, 2011 and 2012, showing receivables by rate class (as defined in the allocated cost of service study) in the following categories:

   i. 0-90 days;

   ii. 90-120 days;

   iii. 120-150 days;

   iv. 150-180 days;

   v. Over 180 days.

Response:

a. Columbia does not produce uncollectible reports by rate schedule. Recent reports, used by the credit and collection function, have been developed showing uncollectibles by residential and commercial, by CHOICE and Non-Choice pulled from its Distributive Information System. The data for the months of October 2011 through October 2012 are contained in Attachment A to this response. Attachment B to this response presents the total charge-offs recorded on the company's books for the 5 years ending May 31, 2012.

b. Columbia's billing system maintains rate schedule information, but for credit and collection activity that detail is not necessary. Therefore, the requested information is not routinely generated.

c. Attachment C to this response contains aging reports routinely created for credit and collection purposes as of September 30, 2011 and September 30, 2012. The reports provide aged receivables for residential, non-residential and total company.

	Residential-Non Choice		Commercial-Non Choice		Total	
	C/O	Recov	C/O	Recov	C/O	Recov
Oct-12	406,704	(111,912)	15,637	(684)	422,341	(112,595)
Sep-12	591,988	(28,737)	15,085	(960)	607,073	(29,698)
Aug-12	988,877	(64,343)	50,956	(19)	1,039,832	(64,362)
Jul-12	1,297,824	(1,370)	38,529	-	1,336,353	(1,370)
Jun-12	379,234	(1,016)	67,337	-	446,572	(1,016)
May-12	312,208	(8,169)	23,667	(948)	335,875	(9,116)
Apr-12	254,468	(5,544)	19,386	(4,885)	273,854	(10,430)
Mar-12	220,738	(7,894)	32,372	(1,688)	253,110	(9,582)
Feb-12	319,368	(12,210)	40,748	-	360,116	(12,210)
Jan-12	307,445	(56,051)	37,954	(805)	345,399	(56,856)
Dec-11	409,319	(67,198)	41,937	(1,812)	451,256	(69,010)
Nov-11	587,820	(114,267)	39,076	(20,023)	626,896	(134,290)
Oct-11	740,779	(98,467)	58,088	(11,711)	798,868	(110,178)

	Residential-Choice		Commercial-Choice		Total	
	C/O	Recov	C/O	Recov	C/O	Recov
Oct-12	38,363	(4,207)	5,136	(4)	43,499	(4,211)
Sep-12	49,183	(670)	1,798	-	50,980	(670)
Aug-12	81,688	(11,828)	6,114	-	87,802	(11,828)
Jul-12	64,223	(180)	2,624	1	66,848	(178)
Jun-12	21,456	(305)	2,443	-	23,899	(305)
May-12	29,761	(7)	1,298	-	31,059	(7)
Apr-12	16,228	(655)	470	(2)	16,698	(657)
Mar-12	20,384	(1,508)	1,001	-	21,385	(1,508)
Feb-12	23,258	(684)	1,153		24,411	(684)
Jan-12	30,133	(531)	2,066	-	32,200	(531)
Dec-11	38,625	(1,980)	974	-	39,598	(1,980)
Nov-11	66,735	(6,218)	6,919	-	73,654	(6,218)
Oct-11	37,949	(4,994)	630	(733)	38,579	(5,727)

	Residential-Total		Commercial-Total		Total	
	C/O	Recov	C/O	Recov	C/O	Recov
Oct-12	445,067	(116,118)	20,773	(688)	465,840	(116,806)
Sep-12	641,171	(29,408)	16,882	(960)	658,053	(30,368)
Aug-12	1,070,565	(76,171)	57,070	(19)	1,127,635	(76,190)
Jul-12	1,362,048	(1,549)	41,153	1	1,403,201	(1,548)
Jun-12	400,690	(1,321)	69,780	-	470,471	(1,321)
May-12	341,970	(8,176)	24,965	(948)	366,934	(9,123)
Apr-12	270,697	(6,199)	19,856	(4,887)	290,553	(11,087)
Mar-12	241,122	(9,402)	33,373	(1,688)	274,495	(11,090)
Feb-12	342,626	(12,894)	41,901	-	384,527	(12,894)
Jan-12	337,578	(56,582)	40,021	(805)	377,599	(57,387)
Dec-11	447,944	(69,178)	42,911	(1,812)	490,854	(70,990)
Nov-11	654,555	(120,485)	45,996	(20,023)	700,550	(140,508)
Oct-11	778,728	(103,461)	58,719	(12,445)	837,447	(115,905)

Columbia Gas of Pennsylvania, Inc.

Month	Year	Sales Gross Charge-offs 144-10860 $	Sales Recoveries 144-10870 $	Choice Gross Charge-offs 144-10861 $	Choice Recoveries 144-10871 $	Choice Marketer Gross Charge-offs 144-10863 $	Choice Marketer Choice Recoveries 144-10873 $
Jan	2007	484,875.24	(315,774.81)	11,603.66	(10,991.46)	799.12	426.47
Feb	2007	489,269.42	(386,140.28)	11,701.96	(13,199.71)	325.01	37.87
Mar	2007	407,967.54	(220,759.73)	12,717.63	(14,291.67)	1,102.72	585.82
Apr	2007	383,675.50	(169,280.39)	13,350.67	(5,133.22)	126.08	(189.37)
May	2007	583,746.70	(178,554.21)	17,856.96	(6,973.97)	1,292.35	2,153.80
Jun	2007	821,686.66	(156,709.34)	14,662.32	(90.01)	0.01	90.77
Jul	2007	1,925,765.24	(238,996.83)	33,860.81	(6,026.12)	74.20	0.00
Aug	2007	1,867,582.53	(112,884.98)	30,880.13	(11,899.55)	831.93	340.22
Sep	2007	1,472,788.42	(316,702.13)	21,140.27	(9,475.07)	1,630.61	305.81
Oct	2007	983,268.23	(595,560.37)	22,157.22	(9,946.41)	1,076.67	(78.12)
Nov	2007	730,413.33	(829,101.05)	23,201.51	(20,192.62)	1,085.03	741.48
Dec	2007	568,523.90	(357,427.99)	14,731.70	(9,951.12)	198.27	152.90
Jan	2008	474,344.28	(287,516.60)	13,318.79	(9,996.32)	521.01	(55.87)
Feb	2008	414,749.73	(263,474.61)	19,809.42	(8,938.49)	256.99	(477.45)
Mar	2008	378,869.17	(210,609.36)	15,821.72	(129.89)	746.88	(700.06)
Apr	2008	508,177.76	(197,721.71)	14,994.21	(830.08)	242.35	(162.74)
May	2008	625,317.11	(186,345.40)	12,877.70	(5,804.66)	156.03	(196.72)
Jun	2008	921,874.55	(150,308.18)	20,112.38	(7,046.18)	310.19	929.72
Jul	2008	2,057,726.89	(149,451.31)	20,102.69	(14,008.21)	698.72	34.63
Aug	2008	1,879,453.34	(185,707.56)	27,884.79	1,861.88	815.23	(19.37)
Sep	2008	1,619,358.38	(298,589.68)	21,872.28	(5,094.03)	958.24	(36.40)
Oct	2008	1,181,062.54	(672,227.41)	16,596.07	(3,355.04)	938.85	841.65
Nov	2008	924,433.65	(751,613.38)	35,266.04	(27,019.53)	1,483.92	(626.68)
Dec	2008	677,916.32	(439,404.14)	24,510.11	(10,736.30)	753.36	(449.69)
Jan	2009	525,252.46	(269,592.10)	21,370.42	2,016.30	1,835.86	(8.84)
Feb	2009	528,631.00	(179,767.38)	11,618.07	(5,939.84)	232.79	(162.53)
Mar	2009	468,632.89	(207,318.11)	14,392.81	(8,657.10)	377.40	(96.69)
Apr	2009	607,691.94	(236,654.45)	15,471.84	(2,253.35)	435.79	49.46
May	2009	822,199.07	(177,465.32)	17,821.78	(6,736.80)	49.70	(131.45)
Jun	2009	1,114,980.65	(214,673.88)	19,391.01	(5,476.66)	197.07	355.76
Jul	2009	2,886,969.34	(220,928.66)	50,158.71	(3,365.47)	931.45	25.14
Aug	2009	2,194,825.52	(180,944.51)	58,516.35	(3,219.88)	391.58	126.50
Sep	2009	1,716,145.72	(342,948.85)	43,604.75	(9,945.18)	532.17	80.22
Oct	2009	1,048,500.23	(1,022,972.33)	35,087.37	177,672.65	958.82	63.49
Nov	2009	445,449.42	(1,852,289.71)	243,889.79	(281,870.55)	71.97	1,453.79
Dec	2009	327,746.09	(534,970.14)	28,118.23	(14,146.91)	7.20	(8.31)
Jan	2010	524,160.99	(347,120.35)	25,966.98	(27,098.34)	230.54	(46.36)
Feb	2010	636,278.45	(234,985.76)	89,428.23	(9,258.50)	809.07	200.44
Mar	2010	299,933.48	(223,426.79)	18,457.79	(18,230.42)	81.24	837.85
Apr	2010	255,094.70	(189,891.61)	13,972.84	(8,497.12)	436.05	(606.58)
May	2010	382,466.77	(129,352.59)	18,941.82	(5,053.67)	12.76	(0.61)
Jun	2010	680,158.21	(168,828.19)	31,669.51	(6,425.38)	103.97	698.74
Jul	2010	1,488,759.87	(134,006.29)	62,538.14	(3,251.85)	1,003.43	(115.59)
Aug	2010	1,133,061.53	(184,068.96)	71,232.00	(11,221.05)	273.30	238.20
Sep	2010	1,065,152.97	(326,503.34)	60,200.76	13,147.19	730.34	(503.22)
Oct	2010	691,520.96	(539,088.87)	51,077.96	(23,419.53)	278.84	123.05
Nov	2010	576,726.02	(564,318.51)	70,395.86	(36,339.33)	242.88	242.74
Dec	2010	419,321.49	(476,179.77)	89,944.34	(28,405.20)	441.50	631.73
Jan	2011	337,031.57	(204,760.82)	13,006.89	(19,844.59)	285.72	(37.07)
Feb	2011	304,015.01	(191,128.37)	18,174.26	(8,550.79)	113.16	755.29
Mar	2011	332,595.73	(188,431.89)	11,844.39	(7,633.83)	1,456.23	(1,384.09)
Apr	2011	373,958.28	(131,133.23)	21,898.34	(3,010.42)	16.44	(41.93)
May	2011	531,592.61	(150,343.75)	21,761.59	(8,033.74)	80.17	(3.39)
Jun	2011	646,556.07	(65,774.43)	42,987.66	(2,128.76)	0.01	12.48
Jul	2011	1,518,477.16	(119,595.95)	58,183.00	(2,631.46)	75.89	39.73
Aug	2011	1,190,461.04	(180,913.90)	66,213.34	(5,660.66)	329.24	(44.05)
Sep	2011	1,128,967.95	(295,042.22)	64,378.78	(3,413.15)	442.61	(297.35)
Oct	2011	798,867.52	(472,427.74)	38,337.07	(26,022.07)	242.18	393.55
Nov	2011	626,896.29	(510,789.95)	72,916.71	(23,343.73)	737.40	158.02
Dec	2011	451,371.65	(279,668.49)	39,334.46	(7,664.21)	263.98	(66.90)
Jan	2012	345,398.98	(222,760.90)	31,932.13	(12,301.51)	267.47	(123.17)
Feb	2012	360,116.25	(169,364.31)	23,896.95	(10,104.73)	513.67	(171.55)
Mar	2012	253,110.03	(156,009.93)	20,926.03	(9,975.64)	459.05	(351.74)
Apr	2012	273,854.15	(147,651.45)	16,678.81	(6,965.17)	19.55	5.44
May	2012	335,874.87	(123,069.04)	30,975.78	(10,122.19)	83.43	(0.14)

Columbia Gas of Pennslyvania, Inc.
Aged Receivables as of September 2008 to 2012

	Total AR Balance (1)=(Col. 2 thru 6)	Current (2)	30 to 59 Days (3)	60 to 89 Days (4)	90 To 119 Days (5)	120 or more (6)	Total Delinquent (7)=(Cols. 3 thru 6)
Residential							
Sep-12	$ (13,331,243)	$ (24,047,304)	$ 1,361,697	$ 1,025,506	$ 890,397	$ 7,438,461	$ 10,716,061
Sep-11	$ (10,934,664)	$ (26,186,750)	$ 1,174,699	$ 1,001,122	$ 993,053	$ 12,083,210	$ 15,252,084
Comm/Indust							
Sep-12	$ (2,506,750)	$ (2,965,485)	$ 144,707	$ 54,081	$ 42,539	$ 217,408	$ 458,735
Sep-11	$ (2,616,401)	$ (3,372,515)	$ 126,200	$ 70,808	$ 51,817	$ 507,284	$ 756,109
Total Company							
Sep-12	$ (15,837,993)	$ (27,012,788)	$ 1,506,405	$ 1,079,586	$ 932,936	$ 7,655,868	$ 11,174,795
Sep-11	$ (13,551,065)	$ (29,559,265)	$ 1,300,899	$ 1,071,930	$ 1,044,870	$ 12,590,494	$ 16,008,193

COLUMBIA GAS OF PENNSYLVANIA INC.

R-2012-2321748
Data Requests

Office of Small Business Advocate - Set I

Question No. OSBA I – 028:

Reference Statement No. 15, pages 40 to 42 and Exhibit PAS-2:

a. Please explain in detail how the labor costs associated with gas procurement were derived.

b. Please indicate whether the labor costs include overhead related to employee benefits, information systems, facilities costs, supervision, corporate, etc. Please explain the basis for including or excluding overhead costs.

c. Please explain in detail how the outside legal costs related to gas procurement were derived.

d. Please explain why working capital costs for gas in storage are excluded from the GPC.

e. Please explain why costs for information systems related to gas procurement are excluded from the GPC.

f. Does the accounting for gas procurement in any way rely on the GEAC system referenced by Mr. Fontaine at page 2 of Statement No. 13? Will the accounting for gas procurement in any way rely on the NiFiT system? Please explain your response.

Response:

a. Refer to OSBA I-028 Attachment A. In columns 1 and 2, labor and benefits expenses for employees working on gas cost procurement activities were accumulated for the twelve month period ended May 2012. The labor and benefits shown in columns 1 and 2 include all expenses charged to Columbia Gas of Pennsylvania, Inc. ("Columbia") by these employees. Two of the individuals listed are employees of Columbia and the remaining are NiSource Corporate Services Company (NCSC) employees. All of these employees are engaged in gas procurement activities, the annual 1307(f) filing, quarterly gas cost filings or related accounting activities. As shown on Attachment A, these expenses include 3 employees from Accounting, 17 employees from Commercial Operations and Supply and Optimization, 3 employees from Legal and 12 from Regulatory.

The Historic Test Year labor expense for these employees has been increased consistent with the labor adjustment presented by witness Gore in Statement No.4 on pages 8-11. Merit increases of 3% were applied for 2012, 2013 and 2014. The resulting annualized labor is shown in column 10.

The expenses related to benefits were also increased from the Historic Test Year level to reflect the expenses associated with the Fully Forecasted Rate Year. Column 4 shows the ratio of benefits expenses to labor expenses for each employee. In column 11, these percentages were applied to the Fully Forecasted Rate Year labor expense (column 10) to compute the annualized benefits expense for the Fully Forecasted Test Year.

Column 12 shows the sum of the labor and benefits expense for the Fully Forecasted Rate Year. Based upon each employee's input, the allocation percentages in column 13 were developed. These percentages were multiplied by column 12 to compute the labor and benefits expense shown in column 14. The total of column 14, $439,766.02, is also shown on line 6 of Exhibit PAS-2.

b. The labor and benefits expense shown on Exhibit PAS-2 includes related overheads. The overheads include benefits, such as medical, dental and pension plans, employer paid payroll taxes and unemployment taxes, non-productive time and rental expenses associated with NiSource Corporate Services Company employees. These expenses were included in the calculation because they are attributed to the employees who worked on activities related to gas cost procurement.

c. Outside legal costs related to gas cost activities were $51,042.54 in 2011. Fifty percent of this amount was allocated to gas cost procurement activities and the remaining amount was allocated to all other gas cost related activities. Line 8 of Exhibit PAS-2 shows the outside legal fees related to gas cost procurement activities is $25,521.27.

d. Working capital costs for gas in storage were excluded from the GPC primarily due to the existence of the CHOICE average day balancing program. Under the average day program, NGSs deliver an amount each day equal to the average projected requirements of their customers. Annual deliveries under the program begin in August of each year. By the end of December, the suppliers' cumulative deliveries are less than customers' cumulative requirements, and Columbia's inventory of gas in storage is used to make up the deficiency between cumulative NGS deliveries and customers' requirements through the end of the NGS delivery year. In addition, Columbia's gas storage inventory is used to provide intra-month balancing between customer requirements and NGS deliveries, as well as to provide sufficient supplies to meet CHOICE customer requirements in years in which customer usage exceed average deliveries. That excess is not made up by the NGS until the end of the NGS delivery year.

e. It was determined that the information systems related to gas procurement would still be required in the event there was no Choice program or if all customers were on Choice. GasSource contains pipeline capacity and rate information, capacity release transactions, purchases and off system sales. If all customers were on Choice, Columbia would still have pipeline contracts and the associated demand charges to pay, the capacity release transactions and some off system sales transactions. Likewise, Columbia would still need to plan and forecast the load requirements regardless of whether or not the Company is purchasing and selling the gas. Therefore, the costs for these systems were excluded from this calculation.

f. The accounting system for gas cost procurement relies on GEAC and will rely on NiFit. This system would still be required in the event there was no Choice program or if all customers were on Choice. The gas procurement activity is captured in the GasSource system which currently feeds electronically into the Financial and Accounting Reporting Architecture system ("FARA"). The information from FARA is then fed electronically into GEAC. The GasSource system will still be in place upon implementation of NiFit and data will still be provided electronically into the various accounting systems. The chart of accounts utilized to record the activity will change but the type of activity captured will not. GasSource will be retrofitted with the new chart of accounts to feed information to the new PeopleSoft Accounts Payable Subledger and PeopleSoft General Ledger.

Columbia Gas of Pennsylvania, Inc.
Gas Cost Procurement Calculation
CPA Labor & Benefits

	Benefits	Labor	Total Labor & Benefits	% Benefits	Merit 2012 %	Merit 2013 %	Merit 2014 %	Annualized Labor-June 2012 Merit	Annualized Labor-March 2013 Merit	Annualized Labor-March 2014 Merit	Benefits	FFRY Annualized Labor Plus Benefits	% CPA Time on Gas Procurement	Statement No.15 Exhibit PAS-2
	(1)	(2)	(3)=(1)+(2)	(4)=(1)/(2)	(5)	(6)	(7)	(8)=((2)*(5))+(2)	(9)=((6)*(8))+(8)	(10)=((7)*(9))+(9)	(11)=(4)*(10)	(12)=(10)+(11)	(13)	(14)=(12)*(13)
Accounting 1	25,738.43	63,892.10	89,630.53	40%	3.00%	3.00%	3.00%	65,808.86	67,783.13	69,816.62	28,125.08	97,941.70	5.00%	4,897.09
Accounting 2	3,553.81	7,820.24	11,374.05	45%				8,054.85	8,296.49	8,545.39	3,883.34	12,428.73	60.00%	7,457.24
Accounting 3	26,614.41	66,087.70	92,702.11	40%				68,070.33	70,112.44	72,215.81	29,082.28	101,298.10	11.00%	11,142.79
Gas Supply 1	4,878.74	11,372.09	16,250.83	43%				11,713.25	12,064.65	12,426.59	5,331.13	17,757.72	48.50%	8,612.49
Gas Supply 2	6,977.76	16,183.72	23,161.48	43%				16,669.23	17,169.31	17,684.39	7,624.79	25,309.17	46.50%	11,768.77
Gas Supply 3	11,543.21	30,505.26	42,048.47	38%				31,420.42	32,363.03	33,333.92	12,613.58	45,947.50	85.00%	39,055.37
Gas Supply 4	11,032.23	26,104.36	37,136.59	42%				26,887.49	27,694.12	28,524.94	12,055.22	40,580.15	24.40%	9,901.56
Gas Supply 5	7,385.23	17,273.10	24,658.33	43%				17,791.29	18,325.03	18,874.78	8,070.04	26,944.82	74.60%	20,100.84
Gas Supply 6	5,525.75	13,002.33	18,528.08	42%				13,392.40	13,794.17	14,208.00	6,038.14	20,246.13	48.00%	9,718.14
Gas Supply 7	9,444.55	22,232.00	31,676.55	42%				22,898.96	23,585.93	24,293.51	10,320.31	34,613.82	25.00%	8,653.46
Gas Supply 8	13,572.46	31,345.54	44,918.00	43%				32,285.91	33,254.48	34,252.12	14,830.99	49,083.11	25.10%	12,270.78
Gas Supply 9	5,537.83	12,884.26	18,422.09	43%				13,270.79	13,668.91	14,078.98	6,051.34	20,130.32	80.00%	5,052.71
Gas Supply 10	7,888.50	18,539.84	26,428.34	43%				19,096.04	19,668.92	20,258.98	8,619.98	28,878.96	25.00%	23,103.17
Gas Supply 11	7,032.09	16,419.60	23,451.69	43%				16,912.19	17,419.55	17,942.14	7,684.15	25,626.29	74.60%	6,406.57
Gas Supply 12	10,848.14	28,565.91	39,414.05	38%				29,422.89	30,305.57	31,214.74	11,854.06	43,068.80	90.00%	32,129.32
Gas Supply 13	8,721.98	20,779.59	29,501.57	42%				21,402.98	22,045.07	22,706.42	9,530.74	32,237.16	13.00%	29,013.45
Gas Supply 14	7,145.64	16,595.96	23,741.60	43%				17,093.84	17,606.65	18,134.85	7,808.23	25,943.09	85.00%	3,372.60
Gas Supply 15	5,382.27	12,468.09	17,850.36	43%				12,842.13	13,227.40	13,624.22	5,881.35	19,505.57	48.00%	16,579.73
Gas Supply 16	12,445.34	28,900.12	41,345.46	43%				29,767.12	30,660.14	31,579.94	13,599.36	45,179.30	17.50%	21,686.06
Gas Supply 17	6,039.07	14,016.61	20,055.68	43%				14,437.11	14,870.22	15,316.33	6,599.05	21,915.38	48.00%	3,835.19
Legal 1	40,855.62	114,896.16	155,751.78	36%				118,343.04	121,893.34	125,550.14	44,644.04	170,194.18	5.00%	81,693.20
Legal 2	43,060.81	128,419.79	171,480.60	36%				130,212.38	134,118.76	138,142.32	49,239.16	187,381.48	11.50%	9,369.07
Legal 3	5,005.98	14,272.17	19,278.15	35%				14,700.34	15,141.35	15,595.59	5,470.17	21,065.76	1.00%	2,422.56
Regulatory 1	28,505.73	65,488.41	93,994.14	44%				67,453.06	69,476.65	71,560.95	31,148.98	102,709.93	40.00%	1,027.10
Regulatory 2	9,563.68	22,124.36	31,688.04	43%				22,788.09	23,471.73	24,175.89	10,450.49	34,626.38	1.50%	13,850.55
Regulatory 3	6,643.33	14,095.98	20,739.31	47%				14,518.86	14,954.43	15,403.06	7,259.35	22,662.40	10.00%	339.94
Regulatory 4	7,228.10	14,007.39	21,235.49	52%				14,427.61	14,860.44	15,306.25	7,898.34	23,204.59	5.00%	2,320.46
Regulatory 5	5,812.43	11,302.63	17,115.06	51%				11,641.71	11,990.96	12,350.69	6,351.40	18,702.09	2.50%	935.10
Regulatory 6	48,467.95	109,958.39	158,426.34	44%				113,257.14	116,654.86	120,154.50	52,962.24	173,116.74	15.00%	4,327.92
Regulatory 7	32,004.76	72,051.73	104,056.49	44%				74,213.28	76,439.68	78,732.87	34,972.47	113,705.34	12.50%	17,055.80
Regulatory 8	8,341.45	19,074.59	27,416.04	44%				19,646.83	20,236.23	20,843.32	9,114.93	29,958.25	2.50%	3,744.78
Regulatory 9	31,986.08	84,068.97	116,055.05	38%				86,591.04	89,188.77	91,864.43	34,952.06	126,816.49	7.50%	3,170.41
Regulatory 10	30,550.89	68,808.71	99,359.60	44%				70,872.97	72,999.16	75,189.14	33,383.78	108,572.92	7.50%	8,142.97
Regulatory 11	19,793.10	51,813.66	71,606.76	38%				53,368.07	54,969.11	56,618.19	21,628.46	78,246.64	3.50%	5,868.50
Regulatory 12	6,653.17	12,703.77	19,356.94	52%				13,084.88	13,477.43	13,881.75	7,270.10	21,151.85	6.00%	740.31
	523,780.53	1,276,075.13	1,799,855.66					1,314,357.38	1,353,788.11		572,349.12	1,966,750.87	22.36%	439,766.02

OSBA Statement No. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2012-2321748
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Rebuttal Testimony of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Gas Procurement Charge Unbundling

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Date Submitted for the Record: 2-13-13 Hbg ®

REBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. Introduction

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

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

Q. What is the purpose of this rebuttal testimony?

A. This testimony responds to the cost allocation and revenue allocation recommendations of Mr. Glenn A. Watkins representing the Pennsylvania Office of Consumer Advocate ("OCA") and Mr. Jeremy B. Hubert representing the Commission's Bureau of Investigation and Enforcement ("I&E"). I also respond briefly to the recommendations of Mr. James L. Crist representing Dominion Retail, Inc., Interstate Gas Supply, Inc., and Shipley Energy Company (collectively, "the NGSs") with respect to the treatment of storage gas working capital costs in the gas procurement charge ("GPC").

Cost allocation, revenue allocation and GPC issues are addressed sequentially in sections 2, 3 and 4 of this rebuttal testimony.

2. Cost Allocation

Q. Please summarize the positions of the various parties regarding cost allocation in this proceeding.

A. The Company submitted three cost of service studies ("COSSs") in this proceeding. All three of these COSSs contain a substantial methodological change from earlier Columbia base rate filings, in that mains are separated into two groups. Costs for mains that are either small diameter or low-pressure ("SDLP") are assigned only to small customers, while the costs for the remaining mains that are both large diameter and high pressure ("LDHP") are assigned to all customer classes. The three Company COSSs are differentiated based on the classification and allocation methodologies for mains costs. The Company's CD COSS uses a minimum system classification/peak demand allocation approach, the P&A COSS methodology uses a 100 percent demand classification/peak-and-average allocation approach, and the third COSS is a simple average of the two.

OCA witness Mr. Watkins opposes the Company's proposed segregation of mains into SDLP and LDHP categories, but otherwise relies primarily on the Company's P&A allocation methodology.[1]

I&E witness Mr. Hubert relies totally on the Company's P&A cost allocation study. Mr. Hubert makes no comment about the proposed segregation of SDLP and LDHP mains, and therefore at least implicitly agrees with the proposed change.

In my direct testimony, I also presented two different COSS methodologies, a ZI COSS based on a zero-intercept classification/peak demand allocation approach and an A&E COSS based on 100 percent demand classification/average-and-excess allocation methodology. In both COSSs, I oppose the segregation of mains into SDLP and LDHP categories. I also make various other technical modifications to the Company's COSSs, notably a change to the peak demand allocators for larger customers to better reflect actual customer peak demands.

Table IEc-R1 below provides a summary of class rates of return at present rates under the various COSSs submitted in this proceeding.

[1] Mr. Watkins also makes an adjustment to the allocation factor for storage plant and gas in storage (Factor 25) ostensibly to reflect an error identified in OSBA-I-12, which I also recognize in my direct testimony. However, it appears that Mr. Watkins overstated the correction by incorrectly including SGDS volumes in his adjustment. Factor 25 should reflect only sales and retail Choice volumes, whereas SGDS volumes are neither. It is my understanding that Mr. Watkins will make this correction in his rebuttal testimony, and that the impact is on class rates of return is relatively small.

Table IEc-R1 Class Rates of Return: Alternative COSS Methods					
	Columbia COSSs		**OCA COSS**	**IEc COSSs**	
	CD	**P&A**	**P&A**	**ZI**	**A&E**
RS/RDS	3.4%	3.9%	4.7%	3.8%	4.6%
SGS/SGDS	7.6%	2.9%	3.7%	4.3%	4.1%
LGS	8.4%	3.5%	0.4%	4.8%	3.5%
SDS	43.9%	13.0%	5.1%	5.8%	3.6%
LDS	34,6%	5.3%	0.6%	4.4%	0.8%
MDS	269.2%	269.2%	285.0%	273.7%	273.7%
Total	**4.1%**	**4.1%**	**4.1%**	**4.1%**	**4.1%**

Note: I&E appears to support the Columbia P&A COSS.
Sources: IEc Workpapers, OCA Statement No. 3 at 12.

As shown in Table IEc-R1, the largest differences in class rate of return among the various methodologies involve the large non-residential classes, SDS and LDS, where the Company's CD method produces class returns that are far above system average while the OCA P&A and my A&E approach produce returns that are below or well below system average. For the residential class, the Company's COSSs and my ZI COSS produce returns that are modestly below system average, while the OCA COSS and my A&E COSS produce similar returns modestly above system average. For the SGS/SGDS classes, the average of the Company's COSSs produces a return modestly above system average, while the OCA and IEc COSSs generally produce returns at or a little below system average.

Q. At pages 9-10 of his direct testimony, Mr. Watkins comments on Commission precedent regarding the proposed SDLP/LDHP mains split. Do you agree with Mr. Watkins' assessment of the precedent?

A. In general, I do. Consistent with Mr. Watkins' testimony, my experience in Pennsylvania is also that no other NGDC splits *joint use* mains costs into SDLP/LDHP components for allocation purposes. Also, I reviewed the 1996 National Fuel Gas Distribution ("NFGD") case upon which Mr. Watkins relies, and I agree that there appear to be reasonably close parallels between the methodology proposed by NFGD and rejected by the Commission in that case and the method proposed by Columbia in the current case.[2] However, I should note that the Commission does permit the direct assignment of dedicated use mains to specific large customers or large customer classes, when such direct assignment can be made. Nevertheless, such direct assignment is a far cry from the proposal made by Columbia in this proceeding.

Q. Is this precedent relevant to Mr. Hubert's position on this issue?

A. It is. In support of the use of the P&A allocation methodology, Mr. Hubert refers to the same 1994 NFGD case cited by Mr. Watkins. It is therefore unclear why Mr. Hubert does not also rely on that case with respect to the issue of splitting mains costs into separate SDLP and LDHP categories.

Q. Mr. Watkins also relies on Commission precedent in concluding that mains costs should have no customer component, and that mains costs should be allocated using a P&A allocation factor. Do you agree with his assessment?

A. Not completely. I agree that Commission precedent supports the classification of mains costs as 100 percent demand-related (i.e., no customer component), both as detailed in my direct testimony and in the cases cited by Mr. Watkins. However, as also detailed in my direct testimony, recent Commission precedent does not support the use of the P&A allocation methodology. Rather, the more recent Commission decisions support the use of an A&E allocation methodology. In particular, in the Philadelphia Gas Works proceeding cited by Mr. Watkins in his direct testimony at page 4, the Commission approved a 50/50 weighted A&E allocation method advanced by the Office of Trial Staff (now I&E) in that proceeding over the 50/50 P&A methodology advanced by the OCA witness and now offered by Mr. Watkins.

Moreover, Commission precedent is not, nor should it be, a bar to parties offering cost allocation methods that they believe better represent cost causation. This is evidenced by

[2] Docket No. R-00942991, 83 Pa. PUC at 359-360. See also Mr. Watkins' direct testimony at 9-10.

Columbia's filing of its CD COSS in this proceeding, my filing of the ZI COSS in this proceeding, and Mr. Watkins' testimony in the recently completed PPL Electric base rates case.[3]

Q. Let's turn to cost causation then. At pages 5-6, Mr. Watkins comments on the relevance of including a customer component of costs to reflect cost causation for more rural utilities. Do you agree with his premise?

A. In part, I do. Mr. Watkins credibly argues that a customer component of costs is justified for more rural utilities, because customers are more spread out, and the utility incurs more distance-related costs.[4] However, Mr. Watkins then appears to conclude that this means that only some utilities with a largely rural service territory should have a customer component in costs, and Columbia is presumably not one of them. In fact, a more reasonable interpretation of Mr. Watkins line of reasoning is that customer classification is not all-or-nothing. Rather, Mr. Watkins logic suggests that the amount of costs which are deemed to be related to customer count should range from NGDC to NGDC, with dense, urban utilities having a lower customer component of costs than spread-out, rural utilities.

And, in fact, both the minimum system and zero-intercept methodologies will show just such a pattern. Rural utilities will require proportionately more smaller-diameter mains, while urban utilities can rely more heavily on larger mains. Both the zero-intercept and minimum system classification methods will produce a larger customer component for the rural utility, consistent with Mr. Watkins' logic.

Q. Mr. Watkins goes on to suggest that because NGDCs do not have an obligation to serve, they are less spread out than electric utilities, and therefore while a customer

[3] Docket No. R-2012-2290597. In that proceeding, Mr. Watkins opposed the use of a minimum system method for classifying primary system distribution equipment into customer and demand components, despite the fact that the Commission had explicitly approved that methodology in the previous PPL Electric base rates case only two years earlier, at Docket No. R-2010-2161694. In its decision in R-2012-2290597, the Commission affirmed its support for classifying both primary and secondary distribution costs into demand-related and customer-related components.

[4] Mr. Watkins references miles of electrical conductors as such an item, but there is a very close parallel to footage of gas mains.

component may be justified for electric utilities, it is not for gas utilities. Do you agree?

A. No, I do not. Under Mr. Watkins hypothesis, one would expect little variability in customer density in natural gas distribution systems, with NGDCs providing service only in relatively densely populated areas. In fact, customer density among NGDCs varies substantially.

The US Department of Transportation Pipeline and Hazardous Materials Safety Administration ("PHMSA") maintains a database of gas distribution utilities, which includes mains footage and number of services.[5] From this information, I compiled the data for all US utilities with at least 30,000 services, and reviewed the distribution of footage of main per service. Among those utilities, the average feet per service value ranged from 34 feet to over 300 feet. Interestingly, the Pennsylvania NGDCs by themselves encompassed almost as wide a range as the total sample, from a low of 34 feet per service at PGW, to 244 feet per service at UGI Central Penn Gas ("CPG") and 245 feet per service at TW Phillips ("TWP"). In effect, CPG and TWP are more than seven times less dense than PGW.

Thus, there a very wide range of system densities among Pennsylvania NGDCs, which runs counter to Mr. Watkins assumption about cost causation. However, the Commission has heretofore not reflected Mr. Watkins' conclusion that more rural utilities should logically include a customer component for distribution plant classification.

Q. How does Columbia rank in customer density in your comparison?

A. The PHMSA data for Columbia reports it at 93 feet per service, exactly equal to the weighted mean for the sample, and a little more dense than the median value of 106 feet per service. Thus, under the customer density hypothesis, Columbia should have a customer component that is a little lower than that for the average NGDC.

[5] See http://phmsa.dot.gov/pipeline/library/data-stats and select Annual Report Data from Gas Distribution . . . Operators.

Q. At pages 7 to 8, Mr. Watkins identifies certain factors which he argues militate against the inclusion of a customer component for mains costs. Do you agree with his arguments?

A. For the most part, I agree with Mr. Watkins' observations about how costs are incurred in constructing gas distribution systems. However, none of these arguments offer strong support for why mains plant does not have both a distance (customer) and size (demand) component for cost classification.

First, Mr. Watkins argues that purchasing economies and other uncertainties are present, causing utilities to install more capacity than is necessary. For cost classification purposes, Mr. Watkins argument would imply that the minimum system approach overstates the customer component of costs, because the minimum system may incorporate more load carrying capability than necessary. Conceptually, I agree that the minimum system approach overstates the customer component of costs. It is for that reason that I use the zero-intercept approach. In the zero-intercept framework, any over-design of the minimum system will not affect the customer component of costs, because the customer component is based on the implied cost of a zero-diameter pipe system. Thus, while Mr. Watkins' logic may be used to conclude that a minimum system customer component is overstated, it does not justify setting the customer component to zero.

Second, Mr. Watkins argues that plant records are far from perfect. While this assertion may be true, it does not affect cost causation. In setting a utility's revenue requirement, regulators use the best available information, namely plant records. Similarly, in classifying plant costs, regulators use the best available information. Inexact plant records are a failing for any cost allocation methodology – regulators simply must work with what they have.

Third, Mr. Watkins argues that it is more expensive to install gas mains in urban areas than in rural areas. Mr. Watkins is unclear as to what he means by more expensive, as he does not say whether he is referring to cost per foot of mains, or cost per unit of throughput capacity. Per foot, it is possible that Mr. Watkins is correct, in that construction in dense urban areas can be more expensive for each foot of trench that needs to be opened.. However, urban areas allow for the use of larger diameter mains, in which carrying capacity increases (at least) with the square of pipe diameter, providing significant economies of scale in construction costs per unit of capacity. In addition, Mr. Watkins provides no quantitative analysis of the alleged effect of higher urban costs on Columbia's system, or in fact whether this observation is even relevant for Columbia. Further, Mr. Watkins assertion would only be relevant for cost allocation if larger customers were more likely to locate in urban areas than in rural areas. Mr. Watkins again provides no evidence that this is the case for Columbia's system.[6] Thus, if Mr. Watkins is indeed correct that urban costs are much higher than non-urban costs, I would agree that costs for urban areas and suburban areas should be allocated separately. If, in fact, larger customers are more likely to be located in urban areas, such an approach would tend to offset the customer component of costs for the urban area, and a separate geographical allocation would reflect that fact. However, as there is no evidence that the cost effect of urban versus rural is material, and it is unlikely that larger customers are more likely to locate in urban areas, it is most unlikely that any attempt to correct for this factor identified by Mr. Watkins would have a material effect on costs allocated to the various rate classes in this case.

Q. At page 8, Mr. Watkins offers certain arguments as to why the allocation of mains costs among the customer classes should reflect both annual use and peak demand. Do you agree with Mr. Watkins' conclusions from a cost causation perspective?

A. No, I do not. Mr. Watkins makes two arguments. First, he argues that because mains are used every day of the year, annual usage represents a logical basis for cost allocation. I disagree. Gas mains must be built to (a) interconnect the customers, and (b) meet peak demands. Whether a customer uses the gas mains at the same level every day of the year, or whether the customer uses the mains only in the heating season, the main must be designed to meet peak demand. This is akin to a car purchase. A customer who buys a five-seat car with the intent of driving it every day with five passengers pays the same

[6] Mr. Watkins also asserts that larger mains in suburban areas tend to be steel rather than plastic. I am unsure of the basis for this conclusion,

amount for the car as a customer who buys the same car with the intent of only using its full capacity once or twice per year. The cost of the car is based on its capacity, and the pricing reflects that cost.[7]

Second, Mr. Watkins argues that design day peak demands are a moving target, and that the current design day demands do not match the design day demands when the system was built. While this assertion is probably true, it is also true that the annual consumption today does not reflect the annual consumption at the time the mains were installed. In effect, to the extent it is relevant at all, Mr. Watkins' argument invalidates the use of annual consumption for cost allocation as much as it invalidates the use of a peak demand allocator. Moreover, today's gas system must still be designed to meet peak demands today, while today's annual consumption has no relevance for today's system requirements. Thus, even though design day demand patterns have changed, they remain relevant to cost causation. Annual consumption, by contrast, had no historical relevance to mains cost causation, and still has none today.

Q. What do you conclude from your review of the intervenor cost allocation evidence?

A. I retain the conclusions from my direct testimony. If the Commission determines that precedent should guide cost allocation, the IEc A&E COSS methodology is most consistent with recent Commission precedent. If the Commission determines that cost causation should guide cost allocation, the IEc ZI COSS methodology should be adopted.

3. <u>Revenue Allocation</u>

Q. Please review Mr. Hubert's proposed revenue allocation.

A. As noted earlier, Mr. Hubert relies on the Company's P&A COSS for revenue allocation purposes. However, rather than develop a full revenue allocation, Mr. Hubert proposes that first dollar relief ("FDR") be granted to certain rate classes that exhibit above-system-average rates of return at present rates, namely the Residential and SDS classes.

[7] Of course, if the customer drives the car more often, he or she will incur more fuel costs. The same logic applies to gas distribution system. The demand-based distribution charge reflects the capacity of the pipe to provide the service; the gas supply charge reflects the usage.

A summary of Mr. Hubert's proposed revenue allocation after FDR is shown in Table IEc-R2 below.

Table IEc-R2 I&E Revenue Allocation Proposal – After FDR			
	P&A COSS Class RoR Present Rates	**Increase after FDR ($000)**	**Percent Increase**
RS/RDS	3.9%	$55,779	33.6%
SGS/SGDS	2.9%	$14,356	37.9%
LGS	3.5%	$582	37.2%
SDS	13.0%	$382	4.0%
LDS	5.3%	$11	0.1%
MDS	269.2%	$1	0.1%
Total	**4.1%**	**$71,111**	**31.0%**
Sources: Table IEc-R1, I&E Statement No. 3 page 27, IEc calculations.			

Q. What is your assessment of Mr. Hubert's proposal for revenue allocation?

A. Mr. Hubert's proposal is reasonably consistent with the COSS methodology upon which he relies. However, as explained in my direct testimony, I disagree with his implicit adoption of the Company's SDLP/LDHP split, and I disagree with his reliance on the P&A allocation methodology, for reasons of both cost causation and Commission precedent. I therefore recommend against adoption of Mr. Hubert's revenue allocation approach.

Q. Please review Mr. Watkins' revenue allocation proposal.

A. Mr. Watkins' revenue allocation proposal is based on consideration of the OCA COSS, which is the Company's P&A COSS adjusted to exclude the SDLP/LDHP split and to modify the Factor 25 allocator. In developing his revenue allocation proposal, Mr. Watkins sets an upper limit on the rate increase for any one class to be no more than 1.5 times the system average increase. Mr. Watkins also considers the effects of revenue shortfalls below full tariff rates for flex customers. Specifically, he proposes that revenue shortfalls associated with potential transmission bypass be shared among all classes, while revenue shortfalls due to NGDC "gas on gas competition" be recovered within the class to which the discounts apply. Mr. Watkins' proposal is summarized in Table IEc-R3 below.

Table IEc-R3 OCA Revenue Allocation Proposal			
	OCA COSS Class RoR Present Rates	**Increase ($000)**	**Percent Increase**
RS/RDS	4.7%	$55,508	33.4%
SGS/SGDS	3.7%	$12,618	33.3%
LGS	0.4%	$802	51.3%
SDS	5.1%	$2,444	25.6%
LDS	0.6%	$5,939	46.2%
MDS	285.0%	--	0.0%
Total	**4.1%**	**$77,311**	**31.0%**

Note: Revenue allocation values and percentage increases include GPC effect.
Source: OCA Statement No. 1, pages 12 and 18.

Q. What is your assessment of Mr. Watkins' proposed revenue allocation?

A. Mr. Watkins' proposed revenue allocation is reasonably consistent with the COSS methodology upon which he relies, as shown in Table IEc-R3. To a large extent, the approach that Mr. Watkins takes to revenue allocation is quite similar to the approach I use in developing the alternative revenue allocation proposals in my direct testimony. We both rely on a 1.5 times system average upper bound. We both recognize that shortfalls related to transmission bypass should be shared among all customer classes. I recommend that discounts due to NGDC "competition" should be eliminated forthwith, where Mr. Watkins proposes that such shortfalls be retained but recovered within the rate class to which they apply. Thus, if the Commission accepts Mr. Watkins' cost allocation methodology, I do not believe that his revenue allocation methodology is unreasonable. Of course, for the reasons detailed above, I do not agree with Mr. Watkins' COSS method.

4. Gas Procurement Charge

Q. Mr. Crist makes various recommendations regarding the Company's proposed GPC. Please summarize where you agree and disagree with his recommendations.

A. My assessment of Mr. Crist's recommendations regarding the GPC is as follows:

1. Mr. Crist recommends that labor costs related to gas procurement be increased to be consistent with similar costs estimated by Peoples Natural Gas and PECO. It is difficult for an outside expert to fully evaluate a utility's claim of this nature, as these costs are determined by a detailed evaluation of how individual employees actually spend their time. As I show in my workpapers, Columbia's labor cost estimate is at the low end of the range of the cost estimates of other Pennsylvania NGDCs on a per-mcf basis, but it is within the range. For that reason I did not take exception to the Company's proposal.

2. Mr. Crist recommends that information systems costs be included in the GPC. As detailed in my direct testimony, I also interpret the Commission's rulemaking to require that such costs be included in the GPC, even if those costs are not directly incremental to providing gas supply. As I have no basis for doing so, I take no position on Mr. Crist's annual cost estimate of $1.28 million, other than to note that Mr. Crist's estimate would appear to far exceed the gas procurement information systems costs identified by any other Pennsylvania NGDC of which I am aware.[8]

3. Mr. Crist recommends that storage gas working capital ("SGWC") costs be included in the GPC. As detailed in my direct testimony, I agree that such costs are a gas supply cost and should be included in the GPC. As I explain, however, the Company currently provides load balancing services to retail shopping customers, including pre-payment for gas in storage. If SGWC costs are included in the GPC as both Mr. Crist and I recommend, the Company should either impose a charge on NGSs for that service, or should require the NGSs to provide their own storage gas.

[8] See IEc workpaper "WP 10 GPC Comparison.xlsx."

4. Mr. Crist recommends that cash working capital ("CWC") related to gas supply should be included in the GPC. As a theoretical matter, I agree. Even after the effect of storage inventory is factored out, the Company likely incurs cash costs for purchasing gas before it receives cash payment from ratepayers. Thus, there is a CWC component to the gas supply function. This theoretical conclusion, however, is tempered by two practical considerations. First, Columbia may also incur CWC costs associated with its purchase of receivables ("PoR") program, if it pays NGSs for gas prior to receiving payment from customers. If that is the case, Columbia should also impose a CWC charge on NGSs, presumably in the form of a purchase price discount. Second, Columbia has not made a CWC cost claim in this proceeding. It is therefore not possible for me to determine whether the Company is actually foregoing recovery of CWC costs related to gas procurement, or if other CWC considerations offset the cost Columbia incurs related to gas supply. In either event, I have no basis for determining whether the Company has or has not implicitly included CWC costs related to gas supply in its base rate proposal, nor do I have any basis for evaluating the magnitude of any such costs.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

OSBA Statement No. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

PENNSYLVANIA PUBLIC UTILITY COMMISSION	:	
v.	:	Docket No. R-2012-2321748
COLUMBIA GAS OF PENNSYLVANIA, INC.	:	

Surrebuttal Testimony and Exhibit of

ROBERT D. KNECHT

On Behalf of the

Pennsylvania Office of Small Business Advocate

Topics:

Cost Allocation
Revenue Allocation
Rate Design
Gas Procurement Charge Unbundling

Date Served: February 7, 2013

Date Submitted for the Record: 2-13-13 Hbg

COMMONWEALTH OF PENNSYLVANIA

February 7, 2013

E-MAIL AND FIRST-CLASS MAIL

Hon. Mark A. Hoyer
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Pa. Public Utility Commission
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Hon. Jeffrey Watson
Administrative Law Judge
Pa. Public Utility Commission
301 Fifth Avenue - #220
Pittsburgh, PA 15222

Re: Pennsylvania Public Utility Commission, *et al.* v. Columbia Gas of Pennsylvania, Inc.
Docket Nos. R-2012-2321748 and M-2012-2323645

Dear Judge Hoyer and Judge Watson:

Enclosed are two copies of the Surrebuttal Testimony of Robert D. Knecht, labeled OSBA Statement No. 3, on behalf of the Office of Small Business Advocate.

As evidenced by the enclosed certificate of service, all parties have been served as indicated.

Sincerely,

Daniel G. Asmus
Assistant Small Business Advocate
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Enclosures

cc: Parties of Record
Robert D. Knecht

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	
v.	:	**Docket Nos. R-2012-2321748**
Columbia Gas of Pennsylvania, Inc.	:	**M-2012-2323645**

CERTIFICATE OF SERVICE

I certify that I am serving two copies of the Surrebuttal Testimony of Robert D. Knecht, labeled OSBA Statement No. 3, on behalf of the Office of Small Business Advocate, by e-mail and first-class mail (unless otherwise noted) upon the persons addressed below:

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Date: February 7, 2013

SURREBUTTAL TESTIMONY OF ROBERT D. KNECHT

1. <u>Introduction</u>

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

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

Q. What is the purpose of this rebuttal testimony?

A. This testimony responds to the cost allocation rebuttal testimony of (a) Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company") witness Mr. John E. Skirtich, (b) Columbia Industrial Intervenors ("CII") witness Mr. Richard A. Baudino, (c) Pennsylvania State University ("Penn State") witness Mr. James L. Crist, P.E., and (d) Office of Consumer Advocate ("OCA") witness Mr. Glenn A. Watkins.

I also respond to the revenue allocation testimony of Company witnesses Paula A. Strauss and Scott D. Phelps, primarily with respect to the issue of rate discounts for customers who have "competitive" options with other natural gas distribution companies ("NGDCs").

Regarding rate design issues, I respond to the rebuttal testimony of Company witnesses Mr. Skirtich and Ms. Strauss as it pertains to the customer charge for SGS/SGDS customers.

Finally, regarding the issue of unbundling gas purchase costs into a gas procurement charge ("GPC"), this testimony responds to the rebuttal testimony of Company witnesses Nancy J. D. Krajovic and Ms. Strauss, OCA witness Mr. Watkins, and Natural Gas Suppliers ("NGSs") witness Mr. James L. Crist.

These four issues are addressed sequentially in sections 2 through 5 below.

Q. Do you have any other introductory comments?

A. As detailed in this surrebuttal testimony, I respectfully disagree with some of the Company's rebuttal testimony and associated analysis. Nevertheless, I acknowledge that the Company undertook a careful review of my recommendations, and has made some reasonable modifications to its filed proposals as a result. In particular:

- The Company has adopted some modest recommended changes to the cost of service study ("COSS") methodology (Statement No. 109-R at 13-15);
- The Company is willing to accept class-differentiated merchant function charges ("MFCs"), reflecting differences in class uncollectibles rates (Statement No. 115-R at 23);
- The Company will reduce the proposed customer charge for smaller SGS/SGDS customers, generally consistent with my recommendation (Statement No. 115-R at 23);
- The Company will modify its SGS/SCD/SGDS rates to better reflect storage gas working capital ("SGWC") cost allocation (Statement No. 106-R at 14);
- The Company will include a provision for information systems costs in the GPC (Statement No. 115-R at 26-27); and
- The Company has expressed a willingness to evaluate an alternative paradigm for recovery of gas supply costs incurred on behalf of shopping customers (Statement No. 116-R at 6-7).

2. <u>Cost Allocation</u>

Q. At pages 9-10 of his rebuttal testimony, in responding to your concerns about separately classifying and allocating small diameter/low pressure ("SDLP") and large diameter/high pressure ("LDHP") mains, Mr. Skirtich states, "Thus, if the smaller mains serve only small customers, and the larger mains proportionately

serve all rates, the company's approach would be reasonable." Is this a fair summary of your direct testimony?

A. Yes, it is. While I retain certain technical concerns about how mains and related costs are segregated into the two categories, and I have additional concerns about the specific classification and allocation methods used within each of the two types of mains, Mr. Skirtich's statement goes to the essence of the issue.

Q. Let's take those conditions one at a time, starting with the latter. Has Columbia offered evidence that large mains proportionately service all customer classes?

A. No. Columbia has not even identified the LDHP mains that serve only large customer classes, nor has the Company identified the smaller customers that do not rely on LDHP mains at all. Both of these specific issues were identified in my direct testimony, and no further evidence was presented in rebuttal.

Moreover, the Company has not offered any systemwide evidence that LDHP mains are proportionately used by all rate classes. The absence of such evidence is particularly problematic in light of the Commission's findings in the National Fuel Gas Distribution ("NFGD") case cited by Mr. Watkins, wherein the Commission stated,

> "At the same time, NFGD did not propose an equally skewed allocation of larger distribution mains to customers with larger throughput based on any analysis of the use of such larger-size distribution mains by smaller customers."[1]

The absence of evidence in this regard does not mean that Columbia's proposal is necessarily unreasonable. However, the absence of evidence does mean that this approach needs a better foundation before the traditional approach is discarded entirely, as the Company proposes.

Q. Turning to the other necessary aspect of the Company's proposal, do SDLP mains serve only small customers?

A. No. Mr. Skirtich argues that the effect is small. However, he has not corrected for the error in his updated COSSs, nor has he provided workpapers supporting his assertion.

---

[1] *NFG v. Pennsylvania Public Utility Commission*, Docket No. R-00942991, 83 Pa. PUC at 359-360 (1994).

Q. Mr. Skirtich, Mr. Baudino and Mr. Crist all argue that, because no LDS customers are served from SDLP mains, there is no reason to assign SDLP costs to those customers. Do you agree?

A. Not necessarily. This argument would make sense if the allocation of LDHP reflected the actual usage of LDHP mains by all customer classes. These witnesses argue that LDS customers should get no share of SDLP mains, but they also implicitly argue that LDS customers should get only an allocated, proportionate share of LDHP mains. However, as I discussed earlier, there is no evidence that LDS customers do not use a disproportionate share of LDHP mains.

In addition, while these witnesses argue that LDS customers should not be assigned any costs associated with SDLP mains, they are willing to assign SDLP mains to residential and smaller business customers who also do not use them. As I indicated in my direct testimony, Columbia allocates SDLP mains based on all Residential and SGS/SGDS loads, despite the fact that a noticeable percentage of Residential and SGS/SGDS loads do not use SDLP mains. For example, roughly one-third of total SGS/SGDS throughput is served from LDHP mains, and yet Columbia includes this load in its allocation of SDLP mains costs, even in its rebuttal COSSs. Because the share of SGS/SGDS load not served by SDLP mains is much higher than that for residential, the Company's method substantially over-assigns costs to SGS/SGDS customers.

In effect, these witnesses conclude that it is unfair to allocate SDLP mains to LDS customers who do not use them, but it is reasonable to allocate SDLP mains to smaller business customers who also do not use them. I disagree.

Q. At page 7 of his rebuttal, Mr. Watkins expresses concern about whether an adjustment to the merchant function charge ("MFC") is appropriate in a base rates proceeding. Please respond.

A. Uncollectibles costs related to gas sales are included in the Company's revenue requirement in this proceeding, and are allocated in all of the COSSs filed in this proceeding. Recovery of these costs is therefore a base rates issue. Moreover, based on my experience, it is standard practice in Pennsylvania that the MFC percentage be updated in base rates proceedings to reflect any overall change in the utility's rate of uncollectibles costs. In this proceeding, I recommend that the MFC rate be updated to reflect differences in the gas purchase uncollectibles rate among rate classes. Based on my experience and upon advice of OSBA counsel, I do not believe there is any procedural problem with my recommendation.

Q. Mr. Watkins goes on to argue that you failed to reflect the increased MFC revenues for residential customers associated with the change in the allocation of gas supply uncollectibles in your analysis. Please respond.

A. In my direct testimony, I did not present a detailed proof of revenue for either of my proposed revenue requirements for each rate class. Had I done so, I would have reflected the increase in the residential MFC revenues in my proposed rates for that class. The increase in MFC revenues represents one component of the overall increase in residential revenues that I recommend in this proceeding. Because I did not make a detailed residential rate proposal, the increase in residential MFC revenues resulting from my cost allocation proposal is implicitly included in my revenue allocation proposal. That increase would occur in exactly the same way that the increase in GPC revenues for smaller sales customers is also included in my revenue allocation proposal. I therefore disagree with Mr. Watkins that I failed to make a corresponding adjustment to revenues related to the change in gas sales uncollectibles costs.

Q. Both Mr. Skirtich (page 18) and Ms. Strauss pages 1 and 9-10) argue that the Company's COSSs present a reasonable range of cost allocation results. Do you agree?

A. No, I do not. In the past, Columbia's application of the minimum system CD method and the P&A method to all mains costs certainly represented a wide range of cost allocation results. However, for the current proceeding, where the Company proposes to assign a large share of mains costs only to smaller customers in both of its COSSs, the Company's alternatives no longer represent the full range of possible COSS results. As shown in

Table IEc-S1 below, the COSS results from both Mr. Watkins' and my studies lie well outside the range of Mr. Skirtich's updated COSSs for most rate classes.[2]

Table IEc-S1
Class Rates of Return: Alternative COSS Methods

	Columbia Updated COSSs		OCA COSS	IEc COSSs	
	CD	**P&A**	**P&A**	**ZI**	**A&E**
RS/RDS	2.3%	3.9%	4.7%	3.8%	4.6%
SGS/SGDS	7.7%	3.0%	3.7%	4.3%	4.1%
LGS	15.0%	7.6%	0.4%	4.8%	3.5%
SDS	40.9%	11.8%	5.1%	5.8%	3.6%
LDS	34.0%	5.1%	0.6%	4.4%	0.8%
MDS	274.1%	274.1%	285.0%	273.7%	273.7%
Total	**4.1%**	**4.1%**	**4.1%**	**4.1%**	**4.1%**

Note: Shaded cells represent minimum and maximum costs allocated (blue for maximum cost, pink for minimum).

Sources: Columbia Statement No. 109-R, Table IEc-R1.

Table IEc-S1 shows that the Company's CD COSS certainly represents the maximum for costs assigned to the residential class, and a minimum for costs assigned to the other rate classes. (Note that the lowest class rate of return implies the maximum cost allocation.) However, the COSS which minimizes costs assigned to the residential class is the OCA COSS. Moreover, the COSSs which maximize costs assigned to the non-residential classes vary from the Company's P&A COSS for SGS/SGDS, to OCA's P&A for LGS and LDS, and my A&E for the SDS class.

Thus, if revenue allocation is to be based on consideration of a wide range of cost allocation results as the Company suggests, such consideration should include not only the Company's COSSs, but also the COSSs submitted by Mr. Watkins and me.

[2] Note that Table IEc-S1 is an updated version of Table IEc-R1 from my rebuttal testimony.

3. Revenue Allocation

Q. Ms. Strauss, Mr. Phelps, Mr. Baudino and Mr. Crist all express concerns about your proposal to move customers who currently benefit from flex rates related to NGDC "competition" to full tariff rates in this proceeding, and generally recommend that the issue be deferred to the generic proceeding. Can you respond?

A. As I indicated in my direct testimony, I am aware that the Commission has initiated a generic proceeding to address this issue. In drafting my direct testimony, I had hoped that the results of that proceeding could apply to the current proceeding, and this long-standing inequity could be resolved forthwith. My current understanding of the schedule for the generic proceeding is that near-term resolution of this issue is most unlikely. In light of this situation, and in consultation with counsel, I withdraw my proposal to adjust rates for those customers in this proceeding. I therefore agree with the recommendations of these witnesses that this particular can must regrettably be kicked down the road once again.

To reflect this change in my recommendations, I modified my revenue allocation algorithms to reflect that Columbia cannot increase rates for *any* of its flex rate customers, and that the shortfall should be absorbed by all other customers (including those in the affected rate class). (All other aspects of my revenue allocation methodology remain the same.) These changes are shown in Table IEc-S2 below. As shown, the effect is to shift revenue from the LDS class (which has the vast majority of NGDC "competitive" flex rate load) to the other rate classes. Summary sheets for each of the revised simulations are attached as Exhibit IEc-S1. Electronic workpapers are available from OSBA upon request.

Table IEc-S2 Updated IEc Revenue Allocation Proposals ($000)				
	A&E COSS Method		ZI COSS Method	
	Original Increase	**Revised Increase**	**Original Increase**	**Revised Increase**
RS/RDS	$49,913	$51,349	$58,939	$59,195
SGS/SGDS	$15,272	$15,600	$13,811	$13,870
LGS	$ 791	$ 791	$ 565	$ 567
SDS	$ 4,824	$ 4,824	$ 2,193	$ 2,206
LDS	$ 6,510	$ 4.746	$ 1,802	$ 1,267
MDS	$ 1	$ 1	$ 1	$ 1
Total	**$77,311**	**$77,311**	**$77,311**	**$77,311**
Sources: IEc Workpapers				

4. <u>Rate Design</u>

Q. At pages 21 to 22, Mr. Skirtich argues that SGS/SGDS customers in the size range for the lower customer charge have meters costs that, on average, are higher than those for average residential customers. Does this observation affect your customer charge recommendation?

A. No, it does not, for two reasons. The first involves consistency with the COSS. The meter cost differentiation to which Mr. Skirtich refers is not reflected in Mr. Skirtich's COSSs. Therefore, from the Company's own cost allocation perspective, there is no difference in allocated costs. The second reason involves rate design philosophy. In my view, for heterogeneous rate classes like the SGS/SGDS classes, the customer charge should reflect the customer related cost for the smallest customers to which it applies. Thus, as meters or services costs increase with customer size, they are more accurately recovered in a commodity or demand charge. Setting the customer charge at the average customer cost necessarily means that small customers will cross-subsidize larger customers within the class. Therefore, Mr. Skirtich's observation that the larger customers (in the group subject to the lower customer charge) have higher meters costs than residential customers is not relevant for setting the customer charge. What is relevant is that the meters costs for the smaller customers in that group are the same as those for residential customers.

Note, however, that this clarification is essentially academic, as Ms. Strauss expressed a willingness to (mostly) adopt my proposed customer charge for smaller SGS/SGDS customers.[3]

5. Gas Procurement Charge

Q. Ms. Krajovic and Mr. Watkins argue that your proposal to reflect SGWC costs in both the GPC and in a charge to Choice NGSs is unnecessarily complicated. How do you respond?

A. The Commission has directed that NGDCs unbundle costs related to gas supply into a GPC, and working capital costs are specifically identified in the regulations as one such cost. My recommendation is therefore consistent with the Commission's regulations. Moreover, SGWC costs are gas supply costs; they are not related to the gas distribution function. My proposal is therefore simpler, because gas supply costs are recovered in charges for gas supply.

Q. Mr. Crist argues that this is not the appropriate forum for determining how SGWC costs incurred for the benefit of Choice customers should be recovered. Can you respond?

A. As was the case for gas supply uncollectibles costs, SGWC costs are included in the Company's revenue requirement in this proceeding, and are allocated to rate classes in all of the COSSs submitted in this proceeding. As both the magnitude of these costs and the allocation of these costs are addressed in this proceeding, I am puzzled by Mr. Crist's assertion that this is not the appropriate forum for determining how those costs should be recovered.

[3] Ms. Strauss suggests that a $21 customer charge be adopted for "simplicity;" I recommended that the customer charge either remain at $20.18 or be set at $20 for "simplicity."

I note also that Mr. Crist indicates that I propose recovering SGWC costs that benefit shopping customers from NGSs. As stated at page 50 of my direct testimony, I propose that such costs be recovered either from Choice customers or from their NGS. At page 51, I suggest that such charges be applied to NGSs, in conjunction with a proposal that would allow NGSs to supply their own SGWC. I view my proposal as providing another opportunity for cost competition, particularly in light of the very high rate of return Columbia requests for its SGWC balances. However, if both the Company and the NGSs are uninterested in competing on this basis, I have no disagreement with recovering these costs from Choice customers, much in the way that Columbia now recovers storage-related purchased gas demand costs from Choice customers.

Q. Mr. Crist argues that Columbia does not incur SGWC costs on behalf of Choice customers. Please respond.

A. Mr. Crist's understanding of the Company's Choice program is very different from mine. Mr. Crist appears to argue that the timing of the annual reconciliation for gas supplies is nothing more than an accounting convention, and that NGSs SGWC obligations are unaffected by any such timing. Mr. Crist also appears to argue that the fact that NGS deliveries fall short of their customers' demand in some months is completely offset by other periods in which NGS deliveries exceed their customers' requirements.

Let me start with the basics. On a cumulative basis, gas purchases must always be greater than gas deliveries to customers. Neither an NGDC nor an NGS can withdraw gas from storage before it has injected that gas into storage. If an NGS's cumulative supply *ever* falls short of that NGS's cumulative customer deliveries, that NGS is relying on some other party to pre-purchase the gas and therefore incur working capital costs. As I explain in more detail below, it is my understanding of the Company's Choice program that cumulative NGS customer requirements do, at some times, exceed cumulative NGS deliveries.

My understanding of the Company's Choice program is that the Company reconciles NGS deliveries with the NGS customer's consumption as of August 1 of each year.[4] As I understand it, this means that an NGS's deliveries for the year-ending July 31 must balance the NGS's customer's consumption for that same period. So, if a NGS starts serving a customer in November, it must have supplied sufficient gas to meet that customer's requirements for November through July (after the cashout reconciliation). Thus, as of August 1, the NGS has contributed zero gas in storage to meet its customers' winter gas requirements. In contrast, Columbia has been filling storage since April to meet its sales customers' requirements, and has also purchased gas to meet the shortfall required by NGSs. Columbia has therefore incurred SGWC costs on behalf of Choice customers. Whether that per-Dth cost is exactly the same as the per-Dth cost it incurs for its own sales customers depends on the relative load profiles of the sales customers and the Choice customers.

My proposals for SGWC cost recovery are based on this understanding. I note that my understanding is consistent with Ms. Krajovic's rebuttal testimony at pages 7 to 11.[5]

Q. Ms. Krajovic argues that if SGWC costs are billed to shopping customers, it will increase confusion regarding the price to compare. Is she correct?

A. No, she is not. Columbia already bills shopping customers for costs related to storage services in the PGDC. While I acknowledge that the current mechanism is confusing, simply adding SGWC costs to an existing charge will not make the problem any worse.

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[4] As Ms. Krajovic explains in rebuttal testimony at page 7, the reconciliation timing is a little more complicated than this to address bill timing, but this is the essence of the mechanism.

[5] My understanding is also consistent with the top half of Ms. Krajovic's Exhibit NJDK-2R, which shows the true-up at the end of July. However, the bottom half of Exhibit NJDK-2R does not show a July true-up, which would imply that the SGWC benefits to an NGS would depend on when a customer switches from sales to Choice service. If there is no true-up as implied by the bottom half of that exhibit, I expect that Choice customers would, in fact, get disproportionately large SGWC benefits, since their NGSs would have a significant incentive to sign up customers at the beginning of the heating season.

Moreover, in my direct testimony, I proposed a generic solution to the problem of customer confusion regarding the price to compare, and the Company has agreed to consider it.[6]

Q. Ms. Krajovic argues that your proposal would cause confusion about cost allocation associated with year-round enrollment. Do you agree?

A. No, I do not. If it so chooses, and if the Commission agrees, Columbia can continue to allocate the costs the way it does now. Currently, Columbia allocates SGWC costs in its COSSs based on sales plus Choice volumes, and recovers the costs in volumetric distribution rates. If these costs were included both in the GPC and in a charge to shopping customers or NGSs, they can continue to be recovered in exactly the same way, namely through a flat volumetric charge. Ms. Krajovic is trying to create complexity where none currently exists.

Q. In your direct testimony, you suggested that the Company offer an option that would allow NGSs to provide their own SGWC, by having the NGSs begin to fill storage in April rather than August as is currently the case. Ms. Krajovic indicates that such a change would have no impact on the NGSs' financing costs and no impact on the Company's management of storage. What is your response?

A. Ms. Krajovic's rebuttal testimony appears to be at odds with the Company's response to OSBA-I-28(d) (included in my direct testimony) and her own rebuttal at pages 7 to11. In both of those locations, the Company argues that it incurred SGWC costs on behalf of Choice suppliers because they only begin filling storage in August, and therefore must necessarily rely on Company inventory to meet their customers' winter requirements. In response to my suggestion, Ms. Krajovic indicates that it doesn't matter when the NGS starts to provide supplies for storage. These positions are simply inconsistent.

To be honest, I do not understand Ms. Krajovic's assertion. Obviously, if an NGS chooses to switch its annual reconciliation for gas supplies to April 1 and the NGS begins filling storage at that time, that NGS will require little if any SGWC from the Company. The NGS will start incurring gas purchase costs earlier than it would under the

[6] See Columbia Statement No. 116-R at 6-7.

Company's proposal, and will need to finance all gas injected into storage until it can begin to recoup those costs from customers in the heating season. Also, if that NGS signs up a customer to start deliveries in November, the NGS will obviously incur a larger cash out charge if it must balance at the end of March than if it can wait to cash out at the end of July. Thus, under this option, Columbia's own storage requirements and SGWC will necessarily be reduced.

Q. Ms. Krajovic also complains that your proposal would require up-front contributions from suppliers and would increase uncertainty in true-up. Can you respond?

A. I agree. These are reasons why I propose this as an option, rather than a requirement. Each NGS can make its own decision. If it wants to incur (or its customers to incur) SGWC costs at the Company's high cost of capital, it can choose to do so. If it wants to avoid those charges by financing its own storage gas and incurring some additional reconciliation uncertainty, it can choose that approach.

Q. At page 12 of his rebuttal, Mr. Watkins opines that the annual cost for SGWC should be based upon the short-term cost of capital. Do you agree?

A. As a theoretical matter, I agree. However, as I indicated in my direct testimony (footnote 38, page 51), the short-term debt in the Company's proposed capital structure is far below that necessary to cover the SGWC requirements. The OCA's proposed capital structure has a similarly inadequate short-term debt share to meet basic SGWC requirements. (OCA Statement No. 2, Schedule MIK-1). Thus, even under OCA's proposed capital structure and rates of return, the Company would earn a return on SGWC well in excess of the short-term cost of capital.

Thus, Mr. Watkins' observation demonstrates why the Company has an economic incentive to keep storage gas in its own rate base and not subject it to competition.

Q. In your direct testimony, you suggest that, if SGWC costs are included in the GPC, the GPC might be better imposed using a percentage approach (like the MFC) rather than a flat per-Dth charge. Ms. Krajovic indicates that your proposal is inconsistent with the Commission's regulations. Please respond.

A. In offering my suggestion, I recognized that while the Commission's regulations specify that both the GPC and the MFC should be expressed as a per-unit charge, the regulations specifically contemplate that the MFC be calculated as a percentage rate and that the unit charge be updated in each annual Section 1307(f) proceeding.[7] For the GPC, however, the regulations do not contemplate a percentage approach, and specify that the GPC be adjusted in base rates proceedings. Nevertheless, it should be recognized that the MFC and GPC have the same basic intent, namely the recovery of NGDC gas supply costs from NGDC gas supply customers.

Moreover, in formulating those regulations, the Commission may not have been aware of a situation where a significant majority of the GPC costs would vary with the price of gas, much in the way the MFC costs vary with the price of gas. Thus, the Commision's requirement for a flat charge may be based on a misunderstanding of the nature of the underlying costs, which are only now being evaluated. Moreover, a percentage approach would both improve the accuracy of the GPC for reflecting costs, and reduce risk to the Company. For example, if gas prices were to rise sharply, the Company would incur a large increase in SGWC costs, but it would be unable to recover those costs in either its GPC or its base rates without filing another base rates proceeding.

In that light, I do not think that it would be unreasonable to request a waiver of the Commission's regulations to allow for a percentage-based GPC, if a waiver is deemed necessary.

Q. Does this conclude your surrebuttal testimony?

A. Yes, it does.

[7] In her rebuttal testimony, Ms. Krajovic quotes the Commission's regulations regarding the definition of the GPC as a per-Dth charge. However, the Commission's regulations define the MFC as "*An element of the PC, **expressed on a per mcf or Dth basis**, that reflects the cost of uncollectibles associated with an NGDC's natural gas costs.*" (emphasis added) Thus, the definition of the GPC cannot, by itself, be a regulatory bar to a percentage-based approach, since Columbia itself uses a percentage-based approach for its MFC.

EXHIBIT IEc-S1

REVISED IEc COSS SUMMARY PAGES

Columbia Gas of Pennsylvania

IEc Zero-Intercept Customer-Demand COSS (Surrebuttal Revenue Allocation): FY Ending June 30, 2014

$000

Summary of COSS	Total	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS/NSS
Present Rates Summary							
Sales Customer Revenues	287,666.281	221,950 8	59,857.0	5,587 4	-	-	271.1
Transport Customer Revenues	90,231.821	51,233.2	15,397.5	-	9,520.3	12,850.8	1,230 0
Miscellaneous Revenues	1,408.790	1,189.3	197.3	1.0	10 1	9.7	1.3
Total Revenue	**379,306.893**	**274,373.3**	**75,451.8**	**5,588.5**	**9,530.5**	**12,860.6**	**1,502.3**
Net Purchased Gas Cost	(150,198.627)	(108,320.5)	(37,601.4)	(4,025.1)	-	-	(251.6)
Net Revenue	**229,108.266**	**166,052.8**	**37,850.4**	**1,563.3**	**9,530.5**	**12,860.6**	**1,250.7**
Other Purchased Gas Costs	1,501.425	1,082 8	375.9	40.2	-	-	2.5
Storage and Transportation	246.630	186.0	55 0	5.3	-	-	0 3
Distribution O&M	44,043 415	30,691.6	8,413.7	311.2	1,883 0	2,736 0	7 8
Customer Accounts	24,904 680	23,184 2	1,682.7	6.3	18 5	11.9	1 2
Customer Service and Info	4,636.847	3,538.1	223.6	12.8	246.3	553.2	62.9
Sales	779.782	710 4	68.3	0.1	0.8	0.2	0 0
A&G	61,640.684	45,114.4	10,518 2	382 8	2,203.1	3,354.2	68 0
Total O&M	**137,763.463**	**104,507.5**	**21,337.4**	**758.8**	**4,351.7**	**6,665.4**	**142.7**
Depreciation	41,961 336	30,114.3	7,181.7	281.8	1,751.1	2,619.5	12.9
Other Taxes	3,688.205	2,644.2	667.9	24 2	141.9	208.2	1.7
Operating Income Before Taxes	**45,705.262**	**28,786.7**	**8,663.4**	**498.6**	**3,285.7**	**3,377.5**	**1,093.4**
Income Taxes	(4,442.824)	(1,742.8)	(1,021 6)	(88.3)	(720.0)	(420.1)	(450.1)
ITC	360.239	253 6	62.6	2.6	16 4	24.9	0.1
Net Income	**41,622.677**	**27,297.6**	**7,704.4**	**412.9**	**2,582.2**	**2,982.3**	**643.3**
Rate Base	**1,011,680.657**	**710,227.6**	**180,396.3**	**8,576.2**	**44,400.0**	**67,845.5**	**235.0**
Class Rate of Return	**4.114%**	**3.844%**	**4.271%**	**4.814%**	**5.816%**	**4.396%**	**273.737%**
Proposed Rates Summary							
Sales Customer Revenues	345,802.683	270,135.7	69,225.5	6,169.5	-	-	272.0
Transport Customer Revenues	109,406.501	64,827.5	20,385 0	-	10,102.0	12,861.9	1,230.2
Miscellaneous Revenues	1,408.790	1,153.5	212.2	2.2	17.9	21.7	1.3
RDK Adjustment	-	(2,548.1)	(501.0)	(15.8)	1,616 6	1,448 3	-
Total Revenue	**456,617.974**	**333,568.5**	**89,321.6**	**6,156.0**	**11,736.5**	**14,331.9**	**1,503.5**
Net Purchased Gas Cost	(150,198.627)	(108,320.5)	(37,601.4)	(4,025.1)	-	-	(251.6)
Net Revenue	**306,419.347**	**225,248.0**	**51,720.2**	**2,130.8**	**11,736.5**	**14,331.9**	**1,251.9**
Other Purchased Gas Costs	1,501.425	1,082.8	375.9	40.2	-	-	2 5
Storage and Transportation	246.630	186 0	55 0	5.3	-	-	0.3
Distribution O&M	45,170.618	31,591.8	8,623.3	319.7	1,891 6	2,736 3	7.8
Customer Accounts	24,904 680	23,184.2	1,682.7	6.3	18.5	11.9	1.2
Customer Service and Info.	4,636.847	3,538.1	223 6	12 8	246 3	553 2	62.9
Sales	779.782	710 4	68.3	0 1	0 8	0.2	0 0
A&G	61,640 684	45,114 4	10,518.2	382.8	2,203.1	3,354.2	68.0
Total O&M	**138,880.666**	**105,407.8**	**21,546.9**	**767.3**	**4,360.3**	**6,665.7**	**142.7**
Depreciation	41,961.336	30,114 3	7,181.7	281 8	1,751.1	2,619.5	12.9
Other Taxes	3,688 205	2,644.2	667.9	24.2	141.9	208.2	1.7
Operating Income Before Taxes	**121,889.140**	**87,081.7**	**22,323.7**	**1,057.5**	**5,483.1**	**4,848.4**	**1,094.6**
Income Taxes	(36,054.181)	(25,931.4)	(6,689 7)	(320.2)	(1,631.7)	(1,030.5)	(450 6)
ITC	360.239	253 6	62 6	2 6	16 4	24.9	0.1
Net Income	**86,195.198**	**61,404.0**	**15,696.6**	**739.9**	**3,867.8**	**3,842.9**	**644.0**
Rate Base	**1,011,680.657**	**710,227.6**	**180,396.3**	**8,576.2**	**44,400.0**	**67,845.5**	**235.0**
Class Rate of Return	**8.52%**	**8.65%**	**8.70%**	**8.63%**	**8.71%**	**5.66%**	**274.03%**

Columbia Gas of Pennsylvania

IEc Average & Excess Demand COSS: FY Ending June 30, 2014

$000

Summary of COSS	Total	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS/NSS
Present Rates Summary							
Sales Customer Revenues	287,666.281	221,950.8	59,857.0	5,587.4	-	-	271.1
Transport Customer Revenues	90,231.821	51,233.2	15,397.5	-	9,520.3	12,850.8	1,230.0
Miscellaneous Revenues	1,408.790	1,189.3	197.3	1.0	10.1	9.7	1.3
Total Revenue	**379,306.893**	**274,373.3**	**75,451.8**	**5,588.5**	**9,530.5**	**12,860.6**	**1,502.3**
Net Purchased Gas Cost	(150,198.627)	(108,320.5)	(37,601.4)	(4,025.1)	-	-	(251.6)
Net Revenue	**229,108.266**	**166,052.8**	**37,850.4**	**1,563.3**	**9,530.5**	**12,860.6**	**1,250.7**
Other Purchased Gas Costs	1,501.425	1,082.8	375.9	40.2	-	-	2.5
Storage and Transportation	246.630	186.0	55.0	5.3	-	-	0.3
Distribution O&M	44,043.415	28,593.8	8,547.8	360.3	2,305.0	4,228.7	7.8
Customer Accounts	24,904.680	23,184.2	1,682.7	6.3	18.5	11.9	1.2
Customer Service and Info	4,636.847	3,538.1	223.6	12.8	246.3	553.2	62.9
Sales	779.782	710.4	68.3	0.1	0.8	0.2	0.0
A&G	61,640.684	42,931.7	10,657.6	433.9	2,642.1	4,907.4	68.0
Total O&M	**137,753.463**	**100,227.1**	**21,610.9**	**858.9**	**5,212.6**	**9,701.3**	**142.7**
Depreciation	41,961.336	28,079.7	7,311.7	329.4	2,160.4	4,067.3	12.9
Other Taxes	3,688.205	2,491.9	677.6	27.7	172.6	316.6	1.7
Operating Income Before Taxes	**45,705.262**	**35,254.1**	**8,250.2**	**347.4**	**1,984.9**	**(1,224.7)**	**1,093.4**
Income Taxes	(4,442.824)	(5,196.9)	(800.8)	(7.5)	(25.2)	2,037.8	(450.1)
ITC	360.239	234.1	63.8	3.0	20.4	38.8	0.1
Net Income	**41,622.677**	**30,291.3**	**7,513.1**	**342.9**	**1,980.1**	**851.9**	**643.3**
Rate Base	**1,011,680.657**	**656,886.6**	**183,804.7**	**9,823.2**	**55,128.6**	**105,802.4**	**235.0**
Class Rate of Return	**4.114%**	**4.611%**	**4.088%**	**3.491%**	**3.592%**	**0.805%**	**273.737%**
Proposed Rates Summary							
Sales Customer Revenues	345,802.683	270,135.7	69,225.5	6,169.5	-	-	272.0
Transport Customer Revenues	109,406.501	64,827.5	20,385.0	-	10,102.0	12,861.9	1,230.2
Miscellaneous Revenues	1,408.790	1,144.1	212.8	2.5	19.8	28.4	1.3
RDK Adjustment	-	(10,385.2)	1,228.4	207.8	4,232.7	4,716.3	-
Total Revenue	**456,617.974**	**325,722.1**	**91,051.6**	**6,379.8**	**14,354.4**	**17,606.6**	**1,503.5**
Net Purchased Gas Cost	(150,198.627)	(108,320.5)	(37,601.4)	(4,025.1)	-	-	(251.6)
Net Revenue	**306,419.347**	**217,401.6**	**53,450.2**	**2,354.7**	**14,354.4**	**17,606.6**	**1,251.9**
Other Purchased Gas Costs	1,501.425	1,082.8	375.9	40.2	-	-	2.5
Storage and Transportation	246.630	186.0	55.0	5.3	-	-	0.3
Distribution O&M	45,170.618	29,493.9	8,757.3	368.8	2,313.6	4,229.2	7.8
Customer Accounts	24,904.680	23,184.2	1,682.7	6.3	18.5	11.9	1.2
Customer Service and Info.	4,636.847	3,538.1	223.6	12.8	246.3	553.2	62.9
Sales	779.782	710.4	68.3	0.1	0.8	0.2	0.0
A&G	61,640.684	42,931.7	10,657.6	433.9	2,642.1	4,907.4	68.0
Total O&M	**138,880.666**	**101,127.1**	**21,820.4**	**867.4**	**5,221.2**	**9,701.7**	**142.7**
Depreciation	41,961.336	28,079.7	7,311.7	329.4	2,160.4	4,067.3	12.9
Other Taxes	3,688.205	2,491.9	677.6	27.7	172.6	316.6	1.7
Operating Income Before Taxes	**121,889.140**	**85,702.8**	**23,640.4**	**1,130.2**	**6,800.3**	**3,620.9**	**1,094.6**
Income Taxes	(36,054.181)	(26,129.9)	(7,186.8)	(332.3)	(2,023.3)	68.7	(450.6)
ITC	360.239	234.1	63.8	3.0	20.4	38.8	0.1
Net Income	**86,195.198**	**59,807.1**	**16,517.4**	**800.9**	**4,797.4**	**3,628.4**	**644.0**
Rate Base	**1,011,680.657**	**656,886.6**	**183,804.7**	**9,823.2**	**55,128.6**	**105,802.4**	**235.0**
Class Rate of Return	**8.52%**	**9.10%**	**8.99%**	**8.15%**	**8.70%**	**3.43%**	**274.03%**