COLUMBIA STATEMENT NO. 101-R

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
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	)	
	)	
vs.	)	Docket No. R-2012-2321748
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	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

MARK R. KEMPIC

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. Mark R. Kempic, Southpointe Industrial Park, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as the President.

Q. Are you the same Mark R. Kempic who submitted Direct Testimony in this Proceeding?

A. Yes I am.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony of the Commission's Bureau of Investigation and Enforcement ("I&E") witnesses Rachel Maurer and Emily Sears regarding Columbia's management performance.

Q. Do you agree with Ms. Maurer and Ms. Sears that Columbia's performance is "average" and Columbia should not be compensated in recognition of the Company's superior performance?

A. No. I&E's witnesses claim that the Company's performance is "average" in the area of customer satisfaction was based on one year's worth of information from the Commission's Quality of Service Benchmarking Report and UCARE reports even those reports often report three years' worth of information. Ms. Maurer ignored both the rest of the data in the Commission's reports and the longer term customer satisfaction information that I provided in my direct testimony from Thoroughbred Research, Metrix/Matrix and our call center's reports. Just as it

would be inappropriate to determine temperature patterns based on one year's data, it is inappropriate to conclude that the Company's performance is better or worse than average based on one year's data. When viewed in its entirety, this information demonstrates that the Company consistently provides superior customer service over the long term.

Q. Please Explain.

A. In Figure 1 below, I have replicated the tables Ms. Maurer used in her testimony as her basis for concluding that the Company should not be granted a higher return based on Columbia's superior customer service performance. I then added the remaining information for the other two years contained in the Commission's 2011 report and average the information for both Columbia and for Pennsylvania's other Natural Gas Distribution Companies. This information appears in columns to the right of her original columns. Based on this analysis, Columbia exceeded the industry average by more than 1% in 11 of the 27 categories. Columbia met or exceeded the industry average by less than 1% in 9 more categories. Columbia met the industry average in 2 categories. Columbia fell below the industry average by less than 1% in four categories, and Columbia fell below the industry average by more than 1% in only 1 category. Of the 11 categories in which Ms. Maurer claims Columbia performed below the industry average, Columbia actually exceeded the industry average in 6 categories by large margins and showed dramatically improved scores in the other categories that had yearly data available. Stated another way, Columbia exceeded industry

averages in 74% of the categories and did not meet industry averages in only 18% of the categories.

Figure 1

	One Year Performance			Three-Year Averages			
	CPA	Industry	Difference	CPA	Industry	Difference	Notes
Call Abandonment Rate	2.00%	3.57%	-1.57%	2.00%	4.42%	-2.42%	
Consumer Ratings of NGDC Representatives - Very Courteous	86.00%	85.00%	1.00%	86.00%	85.00%	1.00%	no yearly data
Ease of Using NGDC's Automated Telephone System	78.00%	77.00%	1.00%	74.33%	70.33%	4.00%	
Field Representative's Courtesy	98.00%	97.00%	1.00%	97.00%	96.33%	0.67%	
Field Representative's Respect for Property	100.00%	98.00%	2.00%	97.66%	97.66%	0.00%	
Overall Satisfaction with Contact: Credit/Collection	91.00%	88.00%	3.00%	91.66%	85.00%	6.66%	
Field Representative's Knowledge	98.00%	95.00%	3.00%	98.66%	95.00%	3.66%	
Busy-Out Rate	0.00%	0.29%	-0.29%	0.00%	0.57%	-0.57%	
Percent of Bill to Small Business Customers Not Rendered Once/Billing Period	0.00%	0.02%	-0.02%	0.00%	0.02%	-0.02%	
Percent of Residential Bills Not Rendered Once Every Billing Period	0.00%	0.01%	-0.01%	0.00%	0.01%	-0.01%	
Consumer Ratings of NGDC Representatives - Very Knowledgeable	79.00%	79.00%	0.00%	79.00%	79.00%	0.00%	no yearly data
Overall Satisfaction with the Way Premise Visit Handled	96.00%	96.00%	0.00%	95.66%	94.66%	1.00%	
Satisfaction that Work Completed Promptly	86.00%	86.00%	0.00%	86.33%	86.00%	0.33%	
Percent of Residential Meters Not Read in 12 Months	0.05%	0.01%	0.04%	0.05%	0.02%	0.03%	
Percent of Residential Meters Not Read by Company or Customer in Six Months	0.14%	0.07%	0.07%	0.16%	0.09%	0.07%	
Satisfaction with NGDC Representative's Handling of the Contact	90.00%	89.57%	0.43%	89.33%	87.33%	2.00%	
Percent of Calls Answered Within 30 Seconds	77.00%	82.29%	-5.29%	79.66%	80.57%	-0.91%	
Satisfaction with Wait to Speak to an NGDC Representative	78.00%	83.00%	-5.00%	80.66%	81.00%	-0.34%	
Overall Satisfaction with Contact: Other	83.00%	86.00%	-3.00%	87.33%	84.33%	3.00%	
Satisfaction that Work Completed in a Timely Manner	85.00%	88.00%	-3.00%	86.00%	87.66%	-1.66%	
Satisfaction with Easy of Reaching NGDC	83.00%	85.43%	-2.43%	85.33%	83.00%	2.33%	
Satisfaction with Using NGDC Automated Phone System	71.00%	72.67%	-1.67%	74.30%	70.33%	3.97%	
Overall Satisfaction with NGDC's Quality of Service During Recent Contact	85.00%	86.43%	-1.43%	87.33%	84.33%	3.00%	
Overall Satisfaction with Contact: Overall	85.00%	86.00%	-1.00%	87.33%	84.33%	3.00%	
Satisfaction with Choices Offered by Automated Telephone System	76.00%	77.00%	-1.00%	77.66%	75.33%	2.33%	
Consumer Ratings of NGDC Representatives - Somewhat Courteous	8.00%	9.00%	-1.00%	8.00%	9.00%	-1.00%	no yearly data
Consumer Ratings of NGDC Representatives - Somewhat Knowledgeable	11.00%	12.00%	-1.00%	11.00%	12.00%	-1.00%	no yearly data

Q. Is there any other evidence to show that Columbia should be granted a higher return based on its superior customer service?

A. Yes. Columbia values the various Commission Reports when gauging satisfaction of our customers, and it uses this information to supplement its own studies and to improve on processes where service quality may be below expectations. However, in addition to using Commission reports, as I stated in my direct testimony, Columbia uses a highly recognized third party vendor "Thoroughbred Research," which performs customer satisfaction transactional surveys nationally for many large industries, including utilities, to aid in determining our customers' overall satisfaction with the Company. This information confirms that Columbia's customer service is above the industry average.

Q. Why does the Company use additional research besides the Commission Reports to measure customer satisfaction?

A. The data presented by "Thoroughbred Research" in figures 2 and 3 of my direct testimony on pages 29-30 (and included below) supports the claim that Columbia provides superior service to its customers over a five-year period. The data in these exhibits present a longer term perspective of customer service metrics and it demonstrates that Columbia's performance has been consistently high over the last five years. It is important to note further that Columbia's performance was higher in each category of customer service in 2011 than it was in 2007, which demonstrates that Columbia's already good performance has further improved. In addition to presenting a longer term view of the Company's customer service performance, the Thoroughbred survey delves deeper into a call center's

performance than that of the Matrix/Metrix transactional survey (used for the Commission's Quality of Service Report), particularly as it relates to the performance of the customer service representatives ("CSR").

Q. Please explain the results found in the "Thoroughbred Research".

A. As you can see in Figure 2 below, this chart reflects a longer term and more detailed examination of the CSR's ability to work with our customers. In each of these detailed categories, Columbia consistently shows strong scores and has maintained or improved its score in each category during the five-year review period.

Figure 2

Columbia Gas of Pennsylvania	2007	2008	2009	2010	2011	2012
Thoroughbred CSR Attributes	12-month a	12-month a	12-month a	12-month a	12-month a	3-Month average March 2012
· Being courteous and professional	0.94	0.93	0.94	0.96	0.96	0.98
· Treating as respected customer	0.94	0.93	0.94	0.96	0.94	0.97
· Showing concern for situation	0.91	0.89	0.91	0.93	0.92	0.94
· Displaying knowledge in job	0.93	0.93	0.93	0.95	0.94	0.96
· Adequately answering questions	0.93	0.92	0.93	0.95	0.94	0.97
· Understanding purpose for call	0.93	0.91	0.93	0.94	0.95	0.98
· Having authority to make decisions	0.89	0.87	0.89	0.92	0.92	0.94
· Working quickly and efficiently	0.91	0.89	0.92	0.93	0.92	0.96
**Source document = Thoroughbred Survey website/Columbia Gas of Pennsylvania/Monthly Flash Report/12-month and 3-month average						

Q. How does Columbia take a balanced approach to provide exceptional customer service?

A. Figure 3 below is data from my direct testimony that shows Columbia's balanced approach using three key statistics:

- Customer Satisfaction (c-SAT) is the long-standing industry standard metric to gauge a company's ability to meet customer needs. Customer Satisfaction measures how a customer feels about Columbia, as a result of their overall experience with our company.
- First Call Resolution ("FCR") measures the effectiveness of Columbia's "execution." Having a high FCR is an indication that our customers are receiving prompt and reliable service that resolves their issues or concerns. It benefits both the customer and the company because it eliminates unnecessary, repeat contacts. Columbia's success with the "first call resolution" is supported by the low percentage (11%) of customers who requested a field visit by our service department, as a follow-up to a phone call received through our call center.
- Ease of Conducting Business is also an important metric because it measures the amount of "effort" that it takes to be a customer of Columbia. We strive to make it easy for our customers to interact with us. This includes providing multiple contact channels, having a variety of bill delivery and payment options, and offering flexible order scheduling. Research shows that customers tend to be more loyal and satisfied toward companies which they feel are easy to do business with.

Delivering successfully on all three of these metrics simultaneously ensures that we continue to provide our customers with excellent, customer-focused service.

Figure 3

Columbia Gas of Pennsylvania, Inc. Performance Statistics

	2009		2010			2011			2012		
CPA	Cust. Sat.	1st Call Res.	Cust. Sat.	1st Call Res.	Ease of Conducting Business	Cust. Sat.	1st Call Res.	Ease of Conducting Business	Cust. Sat.	1st Call Res.	Ease of Conducting Business
Jan	91%	74%	95%	82%	85%	94%	74%	96%	100%	88%	98%
Feb	89%	69%	94%	71%	97%	96%	76%	86%	97%	79%	82%
Mar	95%	59%	96%	61%	94%	93%	90%	94%	96%	88%	97%
Apr	95%	53%	95%	74%	97%	96%	94%	97%			
May	88%	67%	98%	69%	95%	97%	86%	94%			
Jun	97%	56%	91%	65%	91%	95%	75%	86%			
Jul	94%	72%	94%	67%	79%	93%	72%	87%			
Aug	88%	73%	97%	68%	92%	93%	78%	72%			
Sep	97%	64%	97%	77%	87%	90%	84%	88%			
Oct	93%	66%	95%	73%	90%	93%	85%	80%			
Nov	100%	68%	95%	71%	92%	93%	69%	96%			
Dec	94%	72%	89%	72%	97%	97%	78%	91%			
YTD	94%	66%	94%	71%	91%	94%	80%	88%	97%	84%	90%
Target	91%	69%	91%	69%	86%	91%	69%	87%	92%	70%	88%
12 Month Avg	94%	66%	94%	71%	91%	94%	80%	88%	94%	81%	88%

Columbia did not begin tracking the "Ease of Conducting Business" section of the survey until 2010, so there is not any data available for 2009.
The data shown is a monthly snapshot of the metrics tracked by the Customer Contact Center portion of the organization.

Q. Is there anything else from Ms. Maurer's testimony in regards to customer satisfaction that you would like to address?

A. Ms. Maurer also alludes to Columbia's 2011 Call Abandonment Rate of 2% versus the gas industry average of ONLY 3.6% on page 13 of her testimony. What Ms. Maurer does not realize is that the 1.6% difference in abandoned calls represents thousands of calls not answered, consequently resulting in the customer having to call the company back to discuss their issues. The 1.6% difference is a much more significant difference than the raw statistic represents. It takes a substantial amount of expertise and work to achieve the results Columbia has achieved. We consider this statistic very important to our success in providing efficient service to our customers.

Q. What are some other ways that Columbia has provided exceptional service to its customers?

A. For many years Columbia has been an industry leader in providing quality customer service to its customers. Information contained in the Commission's UCARE reports over the past few decades reveals that Columbia has performed exceptionally well in all three areas of the report—Consumer Complaints, Payment Arrangement Requests and Compliance to Commission regulations. Ms. Maurer attempts to minimize Columbia's great successes reported in the UCARE report by stating that Columbia is "only marginally above average," but Ms. Maurer is incorrect.

Q. Please explain.

A. In Figure 4, I have duplicated the table used by Ms. Maurer to conclude that Columbia's performance is "only marginally above average." I then added a column to the right to show the percent that Columbia's performance is above the industry average. While I concede that Columbia's "Response Time to BCS Residential Consumer Complaint (in Days)" is only marginally better than the industry average, Columbia significantly exceeds the industry averages by wide margins with regard to the other metrics. Scores that are 32.97%, 40% and 62.5% above the industry average are definitely significantly above average and are not merely "marginally above average."

Figure 4

	Columbia	Industry Average	Percent Columbia Exceeds Industry Average
Consumer Complaint Rate	0.61%	0.91%	32.97%
Justified Consumer Complaint Rate	0.06%	0.10%	40.00%
Response Time to BCS Residential Consumer Complaint (in Days)	7.3	7.4	1.35%
Commission Infraction Rate	0.03%	0.08%	62.50%

Q. Ms. Sears also states that Columbia should not be recognized for replacing more pipe than other NGDCs. Do you have a response?

A. While it is true that Columbia met with the Commission's Pipeline Safety Staff as part of the Pipeline Safety Staff's "Gas Reliability, Security, and Safety Operations & Maintenance" investigation of the gas industry, the Pipeline Safety Staff also met with every other NGDC in Pennsylvania as a result of the same investigation. As a result of that generic investigation, Columbia evaluated its system and voluntarily took action in the form of adopting an accelerated pipeline replacement program and an accelerated leak detection and repair program. Please refer to Witness Cote's statements (Columbia Statement No. 8 and 108-R) in this proceeding for further explanation of Columbia's replacement efforts. While Columbia made the decision to begin its accelerated pipeline replacement program in 2007, no other NGDC in Pennsylvania had adopted such aggressive measures at that time even though they also met with the Pipeline Safety Staff.

Columbia should be recognized for its leadership in this area through the addition of 10 basis points as outlined by Company witness Moul.

Q. Ms. Sears also states that Columbia should not be recognized for its DIMP because it is simply adhering to requirements. Do you have a response?

A. As Company witness Cote testifies in his rebuttal testimony (Columbia Statement No. 108-R), Columbia adopted integrity management efforts before the federal DIMP rules became effective. Consequently, Columbia's leadership in this area should be recognized in the allowed return on equity.

Q. Is there any other support for awarding a higher equity return allowance for Columbia's management efficiency?

A. Yes. Columbia has also been an industry leader in developing and implementing the first gas Customer Assistance Program ("CAP") and was among the first to offer a CHOICE® program even before either was required by law. Columbia's CAP consistently receives excellent reviews by third party evaluators and it was even cited as a model for another utility to follow because of the manner in which Columbia manages the CAP. (See Docket A-2008-2063737.) With regard to Choice®, Columbia is among the very few natural gas distribution utilities in Pennsylvania with more than ten suppliers actively participating in its CHOICE® program at any given time. In addition to a large number of suppliers, Columbia's customer participation levels are consistently among the highest in the state. As shown in Figure 5 below, as of December 31, 2012, Columbia continues to lead the Commonwealth of Pennsylvania with regard to the number of customers in its Choice® program by a large margin. More than 31% of

Columbia's residential customers take CHOICE® service, compared to the statewide gas industry average of 8.7%.

Figure 5

Monthly PA Gas Switch Update

CUSTOMERS SWITCHING TO A NATURAL GAS SUPPLIER

DECEMBER 2012***

Natural Gas Utility	Total Switching Customers			Residential Switching Customers			Commercial Switching Customers			Industrial Switching Customers		
	#	%	% of Load	#	%	% of Load	#	%	% of Load	#	%	% of Load
Columbia Gas of PA	114,393	27.6	80.2	103,898	27.8	31.2	10,282	26.2	71.0	213	42.9	99.5
Equitable Gas	18,352	7.0	70.0	14,973	6.0	7.0	3,282	19.0	75.0	97	71.0	100
National Fuel Gas	24,180	11.4	77.4	19,549	10.0	11.4	4,240	28.0	75.5	391	60.6	99.1
PECO	48,630	9.9	66.9	40,274	8.9	8.8	7,456	18.1	37.2	900	100	100
Peoples Natural Gas	92,637	26.0	75.0	84,313	26.0	25.0	8,156	29.0	70.0	168	83.0	99.0
Peoples TWP	61	0	87.7	0	0	0	46	1.0	43.1	15	79.0	99.1
Philadelphia Gas Works	2,861	.6	47.5	0	0	0	2,718	10.5	56.3	143	19.6	74.8
UGI	42,656	12.2	91.8	30,965	9.9	11.0	10,885	31.9	81.9	806	58.5	99.8
UGI Central Penn Gas	1,771	2.3	82.1	135	.2	.2	1,479	14.5	71.2	159	53.2	99.5
UGI Penn Natural Gas	5,351	3.3	84.6	917	.6	.8	4,278	27.2	77.2	156	70.9	99.8
Valley Energy	47	.7	88.5	0	0	0	27	3.5	15.4	20	69.0	94.4
Statewide Total	350,939	12.2*	77.4**	295,024	11.7	8.7	52,847	22.8	61.3	3,068	61.4	96.8

(Approximately 2,643,000 Residential + 232,000 Commercial + 5,000 Industrial = 2,880,000 Total Customers)

* Percentage based on the total number of customers of natural gas distribution utilities subject to Chapter 22, Natural Gas Competition, of the Public Utility Code, 66 Pa. C.S. §§2201 – 2212

** Percentage represents alternative supplier load (volume of gas in MCF) billed during the reporting month, compared to the total load of the gas company

*** In order to include information regarding the number of customers who have switched during the reporting month together with the percentage of load (volume of gas in Mcf) delivered by alternative suppliers, it is necessary to compile actual usage information based on monthly customer meter readings and billing processes. Complete usage data is not immediately available with the settlement process ranging from 30 to 60 days.

PENNSYLVANIA PUC

Columbia has also implemented several other programs to enhance its customer service, such as a 10 day tap pledge, which ensures that new customers are connected to our company main within 10 days after all PennDOT permits are received. As another example, Columbia's call-ahead feature alerts customers ahead of time that we are going to work a customer-requested order. This process eliminates orders where a customer may forget about a scheduled

appointment. This creates efficiencies for our customer service technicians by allowing them to work additional non-priority orders in a timely manner. These are only a few of the reasons that we believe that Columbia has provided exceptional customer service to its customers and continues to be a leader within the utility industry in developing new services to enhance customer service and to better connect with our customers.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 102-R

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	)	
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	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
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REBUTTAL TESTIMONY OF

AMY L. EFLAND

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. My name is Amy L. Efland and my business address is 200 Civic Center Drive, Columbus, OH 43215.

Q. Are you the same Amy Efland who filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this rebuttal testimony is to respond to the Direct Testimony submitted by Jeremy B. Hubert on behalf of the Commission's Bureau of Investigation and Enforcement ("I&E"). Mr. Hubert recommends the projection for average use per Residential customer for the Fully Forecasted Rate Year ("FFRY") period ending June 30, 2014 to be 89.50 Dth. I will explain why the company does not agree with Mr. Hubert's projection.

Q. How does Mr. Hubert calculate the average use per Residential customer for the FFRY to be 89.50 Dth?

A. Mr. Hubert utilizes the historical use per Residential customer data provided in Columbia's response to the Discovery question I&E-RS-6-D. On page 17 of Mr. Hubert's Direct Testimony, I&E Statement No. 3, he explains that the decrease in average usage for Residential customers over a six year period (2006-2011) is calculated to be 0.20 Dth per year. He calculates the projection of Residential usage per customer of 89.50 Dth by subtracting 0.50 Dth from 90.00 Dth

Q. Do you agree with Mr. Hubert projected average Residential use per customer of 89.50 Dth?

A. No. Mr. Hubert's projection utilizes the historical 2011 usage level of 90.00 Dth represented in the chart on page 12 of my Direct Testimony. This concept chart is not intended to be used in determining the current level of usage, but to demonstrate the long term trend in Residential use per customer. The chart reflects usage information normalized by employing the average HDD for the 30 years ending 2010. This may not have been made clear to Mr. Hubert. The definition of weather normal applied impacts the Residential usage level, but not the overall trend in the data. A similar downward trend would be found when applying the average HDD for the 20 years ending 2011. Since Mr. Hubert does not dispute the 20 year definition of normal proposed by Columbia, a more appropriate historical usage level to use in his calculations of the FFRY would be the Historic Test Year normalized usage of 86.63 Dth (Ex. 10 Sch. 8). The 86.63 Dth reflects the average HDD for the 20 years ended 2011. A discussion of the weather normalization calculation can be found in Statement 2 page 4 in my Direct Testimony. If Mr. Hubert would have utilized the Historical Test Year Residential use per customer level of 86.63 Dth and subtracted 0.50 Dth, the projection for the Fully Forecasted Rate Year use per customer would be 86.13 Dth. This is very close to the forecast proposed by Columbia of 86.05 Dth.

Q. Mr. Hubert states on page 18 line 12 of his Direct Testimony that the Company is projecting a 14.2% increase in average use per Residential customer. Is this accurate?

A. No. Mr. Hubert compares an actual or non-weather normalized usage level to a weather normalized forecast. The historic test year usage level of 76.06 Dth he uses

in his calculation to arrive at the 14.2% is not weather normalized. When normalized, the Historic Test Year usage level increases to 86.63 Dth (Ex No.10 Sch 8.). This adjustment illustrates the extremely warm weather experienced during the historic test year, reflecting that actual Heating Degree Days (4,659 HDD) were 14.9% below the normal (5,477 HDD). When comparing the Historic Test year normalized Residential usage per customer level of 86.63 Dth, and the Fully Forecasted Rate Year Residential use per customer amount of 86.05 (Exhibit No. 10 Schedule 2 Attachment 1 Page 8) a decline of 0.67% is projected. This is reasonable and is in line with historical patterns.

Q. Do you have any additional comments regarding the forecast methodology utilized by Mr. Hubert to calculate his proposed Fully Forecasted Rate Year Residential use per customer level of 89.50 Dth?

A. Yes. Mr. Hubert calculates an average decrease in Residential use per customer of 0.20 Dth using 30 year normal data from 2006-2011. Aside from the error in using 30 year normals, the use of such a limited time period of information can overstate the influence of short term differences on future projections. The time period employed to calculate the expected future change ought to reflect an average historical trend to ensure that one particular period does not unreasonably influence the forecast. The impact of using a limited time period of information can be seen when comparing Mr. Hubert's calculated decrease of 0.20 Dth in Residential use per customer to the average annual usage decline of 1.75 Dth calculated using data from 2000-2011. The projected decline calculated from 2000-2011 data is almost 9 times greater compared to the projected decline

proposed by Mr. Hubert. This wide discrepancy can also be seen when considering the full time period, 1991-TME July 2012, reflected in the chart on page 12 of my testimony. For this period, the calculated average decline is 1.49 Dth, 1.29 Dth more than Mr. Hubert's 0.20 Dth estimate. Even looking at the average decrease from 2005-2011 (1.19 Dth) or from 2004-2011 (1.78 Dth) shows dramatically different results from Mr. Hubert, further demonstrating the error in picking a particular short term period.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes.

COLUMBIA STATEMENT NO. 104-R

2-13-13
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
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vs.	)	Docket No. R-2012-2321748
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	)	
Columbia Gas of Pennsylvania, Inc.	)	
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REBUTTAL TESTIMONY OF

JEFFERY T. GORE

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. My name is Jeffery T. Gore and my business address is 200 Civic Center Drive, Columbus, OH 43215

Q. Are you the same Jeffery T. Gore that filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to:

- provide an updated claim for operation and maintenance ("O&M) expense;
- provide an updated claim for payroll tax changes;
- provide an updated revenue requirement of $73,682,884 which incorporates adjustments provided by all rebuttal company witnesses and the impact of $3.2 million of incremental capital that will be spent in the second half of 2013 as discussed by Witness Cote in Columbia Statement No. 108R;
- respond to recommendations made by Ms. Wilson, witness for the Bureau of Investigation and Enforcement ("I&E"), and/or Mr. Catlin, witness for the Pennsylvania Office of Consumer Advocate ("OCA") regarding the Company's pension claim; and
- respond to recommendation made by Ms. Wilson and Mr. Catlin regarding NIFIT costs.

UPDATED CLAIM FOR O&M EXPENSE

Q. Please summarize the impact of the Company's updated claim for O&M Expense.

A. Exhibit JTG-R2, Schedule 1, Page 1 provides an updated summary of O&M expense. This schedule is formatted similar to Exhibit No. 104, Schedule No. 1,

Page 2 of 2 in the original filing. The data that has been updated in Columns 2, 3, 5 and 6 is identified with solid lines forming a box around the changed amounts. Additionally, five new lines have been added to the schedule and are identifiable with a letter "a" included in the Line number reference. The revised claim for O&M expense is $135,906,852, a $1,846,606 decrease from the original claimed amount. Pages 2 thru 10 provide support for various adjustments included on Page 1 and are noted in the reference in the far right column of Page 1. Additionally, Confidential Exhibit JTG-R1 reflects an update to the 55 new hire status.

Q. Is the Company updating the capitalization percentage of 67.47% as originally filed?

A. Yes. Exhibit JTG-R2, Schedule 1, Page 2 provides an updated O&M to total cost percentage of 66.16%. The inverse or 33.84% reflects the capitalization percentage. This calculation has been updated to reflect the five year average for calendar years 2008 thru 2012 as recommended by Witness Catlin, as Mr. Catlin's proposal is more reasonable than that of Ms. Wilson. These percentages are used in multiple line item calculations discussed further in this rebuttal testimony.

Q. What adjustments were made to the revised Labor claim on Exhibit JTG-R2, Schedule 1, Page 1, and Line 1?

A. Pages 2 thru 6 support the new FTY and FFRY adjustments in Columns 2 and 5, respectfully. The changes reflect the following adjustments, (a) update using the 66.16% O&M to total cost rate, (b) update reflecting the change in the union

contract increases in the FFRY period, (c) update to the affiliate labor percentage using a detailed evaluation by employee type, and (d) the change to the planned 2013 and 2014 non-union wage increase date from March to June.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1, Line 1a titled Normalized Test Year Labor – Capitalized % Adjustment?

A. The normalized historic test year labor included in Line 1, Column 1 reflected expense calculated using the 67.47% O&M expense to total labor percentage as originally filed. Line 1a reflects the reduction to the Line 1, Column 1 Labor to reflect the revised 66.16% O&M expense to total labor rate. The adjustment is calculated on Exhibit JTG-2, Schedule 1, Page 7 and reflected on Line 1a, Column 2.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1, Line 2 for Incentive Compensation?

A. The Incentive Compensation for the FTY and FFRY periods has been updated to reflect the 66.16% O&M to total expense factor. The details on this adjustment are provided on Page 8 and Lines 2 and 7 reflect the new percentage.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1, and Line 3 for New Employees after Historic Test Year?

A. Confidential Exhibit JTG-R1 reflects the most current hiring status of the 55 new employees and includes the updated hire dates and wages. Also included at the bottom of this page is a revised percentage of O&M labor to total labor, 34.49%, for the new employees, which was utilized in the benefit calculations in Line 6 of JTG-R2, Schedule 1, Page 1.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1, Line 4 for Pensions?

A. Exhibit JTG-R2, Schedule 1, Page 1, Line 4 has been updated to reflect the updated 33.84% capitalization percentage, as detailed in Exhibit JTG-R2, Schedule 1, pages 9 and 10.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1, Line 6 for Other Employee Benefits?

A. Per the detail provided in Exhibit JTG-R2, Schedule 1, Pages 9 and 10, it has been updated to reflect the updated 33.84% capitalization percentage as well as the new 34.49% capitalization percentage for the new employees.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1, Line 8 for Rents and Leases and Line 8a for Rents and Leases Adjustment?

A. The Company identified an adjustment needed for Rents and Leases in response to I&E-RE-96-D. This adjustment was reflected in OCA witness Catlin's Exhibit TSC-3 and also addressed by I&E witness Wilson. The Company's total claim was reduced by $67,625 of which $33,699 was related to the FTY. Line 8 reflects this adjustment. Additionally, the discovery response identified the remaining $33,926 adjustment related to the normalized test year amount. This adjustment is included in Line 8a. (See, I&E Exhibit No. 2, Schedule 11.)

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1, Line 9 for Corporate Insurance?

A. As noted by Mr. Catlin, the original corporate insurance claim had some inconsistencies. The adjustment in Line 9 eliminates the 5% adjustments in

Columns 2 and 5 and only includes an inflation adjustment for the FFRY period. Additionally, the revised claim includes an adjustment to use the 33.84% capitalization percentage.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1, Line 19a for Other O&M – Longwall Mining?

A. The amortization of the Longwall Mining regulatory asset was included in the Other O&M in Line 19. As this amortization will be completed approximately by the time the revised rates from this case go into effect, this amortization plus inflation adjustments are removed from the claim.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1 Line 22a for Lobbying?

A. The lobbying adjustment included in Line 22 adjusted HTY costs with inflation rates in the FTY and FFRY periods. As identified in response to I&E-RE-102-D, the lobby expense includes some company labor and the inflation adjustments that were not adequate to offset the labor increases in Line 1. This $421 adjustment ensures the lobbying expense credit is sufficient to offset costs in the FTY and FFRY.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1, Line 23 for PUC, OCA OSBA Fees?

A. The original claim reflected the most recent fees billed to the Company. As noted in response to I&E-RE-103-D, the September 2012 invoice was received and the claim reflects this more recent expense amount. See attached Exhibit JTG-2, Schedule 7 for a copy of this discovery response.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 2, Line 25 for System Services?

A. The Company identified in discovery response I&E-RE-111-D an update for pension costs. The FTY expense was reduced by $35,989 and the FFRY expense was increased by $7,197. See attached Exhibit JTG-2, Schedule 8 for a copy of this discovery response.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1, and Line 33 for Odorization?

A. The original claim reflected costs related to seven odorization stations and the Company has identified that only six stations are needed as described in the Company's response to I&E-RE-127-D and referenced by Ms. Wilson in her testimony.

Q. What adjustments were made on Exhibit JTG-R2, Schedule 1, Page 1, Line 34a for Polypipe?

A. In December 2012, the Company reached agreement with a supplier of plastic pipe to reimburse the Company for costs associated with locating, identifying and replacing plastic pipe that had a manufacturing abnormality that reduced its intended service life. As the Company will be reimbursed for these costs by the supplier, the amounts included in this claim for this remediation work should be removed and not included in rates to customers. The historic test year included $863,798 of costs, primarily in the Outside Services claim in Line 7. Because these costs were inflated in the FTY and FFRY, the adjustment in Line 34a includes similar inflation adjustments to ensure the total claim is appropriately

reduced by the full impact of these costs.

UPDATED CLAIM FOR PAYROLL TAXES

Q. What adjustments were made to the Claim for payroll taxes?

A. There are two adjustments, (1) changing the percentage of total taxable from 99.18% to 99.17 % in lines 1 and 5 of Exhibit JTG-R2, Schedule 2, Page 2 as described in response to I&E-RE-128-D, and (2) updating the payroll adjustment in lines 3 and 7 to reflect the impact of the changes made to salary expenses in Lines 1 through 3 of Exhibit JTG-R2, Schedule 1, Page 1.

UPDATED REVENUE REQUIREMENT CLAIM

Q. Please describe the information provided in Exhibit JTG-R2, Schedule 3.

A. This schedule provides the updated claim of $73,682,884 in this case. The claim is noted in two calculations; $73,284,617 of revenue requirement based on all the various updates and adjustments included in the Company's rebuttal testimony and $398,267 of revenue requirement based on the impact of incremental capital spend allocated to the Company as described by Witness Cote.

Q. Please describe the information provided in Exhibit JTG-R2, Schedule 4.

A. The first 4 pages reflect updated Exhibit 102, Schedule 3 information. Included in this revised calculation are changes to revenues, O&M expenses, depreciation, other taxes, income taxes, rate base and cost of capital. The information that is updated from the original filing is shown outlined in solid lines.

Q. What adjustments have been made to revenues?

A. The FFRY revenue adjustments noted on Exhibit JTG-R2, Schedule 4, Page 1, Column 7, Lines 7 & 8 reflect adjustments the Company indicated were necessary

in discovery responses I&E-RS-41-D and I&E-RS-25-D, respectively. (See, I&E Exhibit No. 3, Schedule 1 and Schedule 3.) Specifically, Column 7, Line 7 corrects a double counting of Implied Attrition bills and Column 7, Line 8 reflects the Company's updated claim forfeited discount referenced by I&E Witness Hubert.

Q. What adjustments have been made to O&M expense?

A. The O&M adjustments were described earlier in this testimony and the FTY and FFRY O&M expense reflects the adjustments included in Exhibit JTG-R2, Schedule 1, Page 1. The amounts changed on Exhibit JTG-R2, Schedule 4 for O&M adjustments are on Page 1, Line 15, Columns 3 & 7.

Q. What adjustments have been made to depreciation expense?

A. The FTY and FFRY depreciation expense adjustments in Exhibit JTG-R2, Schedule 4, Page 1, Column 7, Line 16 reflect the updated expense as described in Witness Spanos rebuttal testimony.

Q. What adjustments have been made to Other Taxes expense?

A. The Other Taxes adjustments were described earlier in this testimony and the FTY and FFRY expense reflects the adjustments included in Exhibit JTG-R2, Schedule 2, Page 1. The amounts changed on Exhibit JTG-R2, Schedule 4 for O&M adjustments are on Page 1, Line 18, Columns 3 & 7.

Q. What adjustments have been made to Income Tax expense?

A. Witness Fischer provides all adjustments in her rebuttal testimony. Her Exhibit PWF-1R provides the support for the income tax expense use in the claim calculation.

Q. What adjustments have been made to Rate Base?

A. Witness Krajovic provides all adjustments in her rebuttal testimony. Exhibit NJDK-3R provides the detail supporting the rate base used in the claim calculation.

Q. What adjustments have been made to Cost of Capital?

A. Witness Moul provides all adjustments in his rebuttal testimony. The overall 8.52% return claim is unchanged from the original filing.

Q. Please describe the information provided in Exhibit JTG-R2, Schedule 5.

A. This two page schedule provides the support for the $398,267 revenue requirement resulting from the incremental capital. Page 2 details the $3.2 million spending assigned to mains and services over the last six months of 2013. Within this page, a depreciation expense and accumulated depreciation account balance is calculated based on the depreciation rates as provided by Witness Spanos. Page 1 of this schedule brings forward the rate base as of June 30, 2014 and calculates the revenue requirement with annualized depreciation expense. The Deferred Tax balances and impacts to tax expense were provided by Witness Fischer.

FURTHER SUPPORT FOR PENSION CLAIM

Q. How is the qualified Pension expense claim calculated in this case?

A. The gross qualified Pension claim is calculated as the sum of the actual and expected gross contributions to the pension trust for the 36 months ended June 2014. The average annual gross contribution is then adjusted by the capitalization percentage to determine the claimed expense amount. The capitalization percentage has been updated in this revised claim to reflect the

updated 66.16% O&M to total cost as provided on Exhibit JTG-R2, Schedule 1, Page 1.

Q. How does Ms. Wilson recommend calculating the qualified Pension claim?

A. Ms. Wilson recommends calculating the gross qualified Pension claim using the expected gross contributions to the pension trust for the 24 months ended June 2014. Ms. Wilson argues that using a two year average consistent with the claim in the Company's last case. The average annual gross contribution is then adjusted by the capitalization percentage.

Q. How does Mr. Catlin recommend calculating the qualified Pension claim?

A. Mr. Catlin recommends calculating the gross qualified Pension claim using the expected gross contributions to the pension trust fund for calendar years 2013 and 2014. The average annual gross contribution is then adjusted by the capitalization percentage.

Q. Did the Company propose in direct and rebuttal testimony in its last base rate case to use a two year average of pension trust contributions to develop the pension claim?

A. Yes. I was the witness supporting the development of the pension claim using a two year average of contributions for that case.

Q. Why did the Company change the calculation of the pension claim from a two year to a three year calculation in this case?

A. The Company has proposed to use a three year average in this case because the resulting claim is more representative of the on-going pension costs.

Q. What factors lead you to believe the three year average ending June 2014 of

contributions provides a representative on-going pension claim?

A. There are two primary factors that lead me to conclude the Company's claim is representative and appropriate:

1. The Company made a business decision late in 2011 (after completion of the prior rate case) to make a large pension contribution in the fourth quarter of 2011. As a result of this large contribution, the planned 2012 and 2013 contributions were eliminated and the 2014 contribution amount was tempered. As the fourth quarter 2011 contribution greatly reduced or eliminated 2012 to 2014 contributions, I believe it is appropriate to include this contribution in a multi-year average if the 2012, 2013 or 2014 activity is part of the claim calculation.
2. The gross Pension claim of $6,599,901 in this case (Exhibit JTG2, Schedule 1, Page 10, Line 1, Column 1) is comparable to expected contribution levels in years 2015 and 2016 , $6,684,000 and $6,489,000 respectfully, (provided in Attachment A – I&E-RE-59-A, Line 4, Columns 9 and 11). These years reflect an on-going level of funding after anomaly of the large Q4 2011 contribution and reduced contribution levels in years 2012 – 2014. These contribution estimates reflect the most recent updates provided by the Company's Pension actuarial AON Hewitt.

Q. What was the claimed 2011 pension contribution reflected in the last case?

A. In the prior rate case, the claimed two year average pension contribution reflected an estimate of 2011 contributions of $9,424,800. When averaged with prior 2010 contributions, the claimed contribution was $8.9 million.

Q. What were the actual 2011 pension contributions?

A. The actual total 2011 pension contributions were $15,020,000, with $13,092,000 paid in December 2011.

Q. Is there a benefit to customers from this large pension contribution?

A. Yes. By making an early contribution, the pension trust is able to earn a return on a greater trust balance. This provides a benefit to customers by reducing future pension contributions. This is evident from the Company's ability to avoid contributions in 2012 and 2013.

Q. Did you consider using a two year average in the calculation of the Pension claim?

A. Yes. A two year average calculation using the historic test year and future test year was considered as this was consistent with time periods utilized in the last case. Additionally, a two year average as recommended by Ms. Wilson (2013-2014) was also considered when developing this claim. The former provided a gross claim of $7,510,000 and the later provided a gross claim of $812,250 (Witness Wilson testimony – Page 14, Line 14). This significant difference in these two calculations caused the Company to further review the pension claim calculation in order to ensure the claimed amount was representative of on-going cost levels and not just a high or low amount based on which two year period was utilized in the calculation.

Q. Why did you decide on the 3 year period ending June 30, 2014 for the claim?

A. Given the large variance in the two year average options considered, it was appropriate to use a time period that included both the large contribution

amount and the resulting reduced contribution amounts in later years. The gross Pension contribution average for this period of $6,599,901 provides a claim level that is in the middle of all noted two year average options and is in line with the on-going levels projected in later years. Therefore, the use of this 3 year average claim provides a reasonable estimate to use to set recovery rates for this case.

FURTHER SUPPORT FOR NIFIT CLAIM

Q. Please summarize the Company claim for NIFIT costs.

A. The claim is to defer the O&M expense associated with the installation of the NIFIT project and recover those costs over two years.

Q. Please summarize the positions of Ms. Wilson and Mr. Catlin.

A. Ms. Wilson recommends elimination of internal labor NIFIT costs, while Mr. Catlin accepts the total $2.02 million claim. Both recommend extending the amortization period, Ms. Wilson to five years and Mr. Catlin to four years.

Q. Please summarize Ms. Wilson's concern with recovery of internal labor NIFIT costs.

A. Ms. Wilson contends that the NIFIT installation will occur over a fixed time and is temporary in nature. She is concerned the Company has not substantiated the need or intention to fill those positions.

Q. Can you address Ms. Wilson's concerns?

A. Yes. The NIFIT project is a corporate endeavor that will upgrade and replace financial systems within all NiSource operating companies. The six Columbia distribution companies (which include the Company) are scheduled to be converted to the new financial systems by early 2014. There are multiple phases

beyond this work to convert financial systems for the Indiana operating company, operating companies in the NiSource transmission segment as well as the corporate companies including NiSource Corporate Services. As a result, the NiSource employees assigned to the NIFIT project expect to be fully engaged in these duties for approximately five years. Additionally, due to the magnitude of the project and its impact on the entire company, the employees assigned were key personnel that were well versed in company systems and accounting processes. As a result, each department that provided employees to the project was given approval to fill these positions, and the positions either have been filled or are being filled.

Q. Why did the Company recommend a 2 year recovery period?

A. A two year recovery period was chosen as it aligned recovery of several items in this case. The following items have also been proposed with a two year recovery period:

- Rate case expense as discussed in my direct testimony;
- Passback of remaining tax refund as discussed by Company witness Fisher; and
- Passback of the OPEB deferral as discussed by Company witness Schmelzer

Q. Does this conclude your testimony?

A. Yes.

Exhibit JTG-R1 is

CONFIDENTIAL

Columbia Gas of Pennsylvania, Inc.
Statement of Operations and Maintenance Expense at Present Rates
FTY = Future Test Year TME 5/31/13, FFRY = Fully Forcasted Rate Year Period Ended June 30, 2014

Line No.		Normalized Twelve Months Ended May 31, 2012 (1) $	Adjustments (2) $	1.85% Inflation Adjustment [1] (3) $	FTY Twelve Months Ended May 31, 2013 (4=1+2+3) $	Adjustments (5)	1.56% Inflation Adjustment [1] (6)	FFRY Twelve Months Ended June 30, 2014 (7=4+5+6)	Reference
1	Labor	25,335,318	555,529	0	25,890,847	967,574	0	26,858,421	Pages 2 - 6
1a	Normalized Test Year Labor - Capitalized % Adj	0	(491,911)	0	(491,911)	0	0	(491,911)	Pages 7
2	Incentive Compensation	1,607,482	(291,984)	0	1,315,498	39,397	0	1,354,895	Page 8
3	Labor - New Employees after Historic Test Year	0	1,011,791	0	1,011,791	33,188	0	1,044,979	Exh JTG-R1
4	Pensions	8,026,917	(1,425,031)	0	6,601,886	(2,927,902)	0	3,673,984	Page 9 & 10
5	OPEB	1,571,966	(1,736,839)	0	(164,873)	0	0	(164,873)	
6	Other Employee Benefits	4,347,815	586,467	0	4,934,282	327,738	0	5,262,020	Page 9 & 10
7	Outside Services	14,072,713	0	260,345	14,333,058	0	223,596	14,556,654	
8	Rent and Leases	1,303,330	340,522	0	1,643,852	0	0	1,643,852	
8a	*Rent and Leases Adjustment*	0	(33,926)	0	(33,926)	0	0	(33,926)	
9	Corporate Insurance	2,738,827	0	0	2,738,827	0	42,726	2,781,553	
10	Injuries and Damages	626,855	0	11,597	638,452	0	9,960	648,412	
11	Employee Expenses	1,734,482	0	32,088	1,766,570	0	27,558	1,794,128	
12	Company Memberships	254,168	0	4,702	258,870	0	4,038	262,908	
13	Utilities and Fuel Used in Company Operations	433,994	0	8,029	442,023	0	6,896	448,918	
14	Uncollectible Accounts	3,046,671	(58,407)	0	2,988,264	88,640	0	3,076,904	
15	Uncollectible Accounts -Unbundled-gas	1,817,075	108,765	0	1,925,840	(77,564)	0	1,848,276	
16	Uncollectible CAP-Rider USP	8,428,112	86,501	0	8,514,613	(45,318)	0	8,469,295	
17	Rider USP - LIURP/Energy Efficiency	2,377,160	24,398	0	2,401,558	(12,782)	0	2,388,776	
18	Advertising/Bill Inserting	154,625	0	2,861	157,486	0	2,457	159,942	
19	Other O&M	5,594,498	0	103,498	5,697,996	0	88,889	5,786,885	
19a	Other O&M - Longwell Mining	0	(54,210)	(1,003)	(55,213)	0	(861)	(56,074)	
20	DIMP	0	2,580,000	0	2,580,000	4,990,000	0	7,570,000	
21	Interest on Customer Deposits	153,359	0	0	153,359	0	0	153,359	
22	Lobbying	(129,056)	0	(2,388)	(131,444)	0	(2,051)	(133,494)	
22a	Lobbying - Labor Adjustment	0	(421)	0	(421)	0	0	(421)	
23	PUC, OCA, OSBA Fees	1,405,234	236,400	0	1,641,634	0	0	1,641,634	
24	Charitable Contributions	0	0	0	0	0	0	0	
25	*System Services*	39,821,257	2,379,448	0	42,200,705	1,356,957	0	43,557,662	
26	Emergency Furnace Repair	500,000	0	0	500,000	0	0	500,000	
27	Gas Technology Institute	165,000	42,674	0	207,674	0	0	207,674	
28	Rate Case Expense Normalization	0	522,886	0	522,886	0	0	522,886	
29	Royalties	5,977	0	0	5,977	0	0	5,977	
30	*NIFIT*	0	0	0	0	1,010,000	0	1,010,000	
31	NCSC OPEB costs amortization	90,313	0	0	90,313	0	0	90,313	
32	Education and Outreach	0	300,000	0	300,000	0	0	300,000	
33	Odorization	0	60,746	0	60,746	0	0	60,746	
34	York MGP costs	0	0	0	0	0	0	0	
34a	Polypipe Adjustment	0	(863,798)	(15,980)	(879,778)	0	(13,725)	(893,503)	
35	Total Operation and Maintenance Expense	125,484,092	3,879,599	403,749	129,767,441	5,749,928	389,483	135,906,852	

[1] Exh 104, Sch 2, Pg 21

Columbus Gas of Pennsylvania, Inc.
Capitalization Percentage
Twelve Months Ended December 31, 2012

Line No.	Description	Historic Test Period Per Books	12/31/2012 Per Books	12/31/2008 Per Books	12/31/2009 Per Books	12/31/2010 Per Books	12/31/2011 Per Books	5 Year Average
		$	$	$	$	$	$	
		(1)	(2)	(3)	(4)	(5)	(6)	(7)
1	Labor charged to O&M expense direct	24,202,819	25,686,282	23,881,464	24,456,508	25,204,766	24,494,344	
2	Labor charged to O&M expense via clearing account	338,439	345,030	270,352	235,679	263,243	356,621	
3	Total Charged to O&M accounts	24,541,258	26,031,312	24,151,816	24,692,187	25,468,009	24,850,965	
4	Total payroll per financial 2A page	38,715,833	39,710,174	35,380,550	35,224,099	35,518,297	37,422,286	
5	Non-Productive Time & Net vacation	20,258	285,868	448,440	162,665	(359,679)	163,481	
6	Other companies transfers	1,136,126	1,362,471	747,463	1,189,652	1,201,423	1,074,227	
7	Total Payroll	39,872,217	41,358,513	36,576,453	36,576,416	36,360,041	38,659,994	
8	O&M percentage - (Ln. 3/Ln. 7)	61.5498%	62.9406%	66.0311%	67.5085%	70.0440%	64.2808%	**66.16%**
9	Capital Percentage (100% less Line 8)	38.4502%	37.0594%	33.9689%	32.4915%	29.9560%	35.7192%	33.84%
	Labor Adjustment for Change in Capitalization Rate							
10	Historic Test Year Labor Expense Level	22,569,598						
11	Test year Capitalization Level	61.5498%						
12	Adjusted Capitalization Level	66.1600%						
13	Adjusted Test Year Labor Expense (Line 10/Line 11 x Line 12)	24,260,117						
14	Adjustment Needed	1,690,519						

Columbia Gas of Pennsylvania, Inc.
Adjustment to Payroll
FTY = Future Test Year TME 5/31/13, FFRY = Fully Forecasted Rate Year Period Ended June 30, 2014

Line No.	Description	Reference	Amount (1) $
	FTY Adjustment		
1	Adjusted Annualized Labor @ 5/31/12	Sch.1, Pg. 4, Ln.5	37,370,880
2	Merit Increases in FTY	Sch.1, Pg. 4, Ln.7	839,675
3	Annualized Labor @ 5/31/13	(Line 1 + Line 2 + Line 3)	38,210,555
4	Annualized Labor @ 5/31/12	Sch.1, Pg. 4, Ln.5	37,370,880
5	Adjustment	(Line 3 less Line 4)	839,675
6	O&M Expense Percentage	Sch.1, Pg 2, Ln. 8	66.1600%
7	O&M Payroll Adjustment Existing Employees	(Line 5 times Line 6)	555,529
	FFRY Adjustment		
8	Annualized Labor @ 5/31/13	Sch.1, Pg. 5, Ln.1	38,210,555
9	Merit Increases at 6/01/13	Sch.1, Pg. 5, Ln.3	328,937
10	Merit Increases in FFRY	Sch.1, Pg. 5, Ln.6	1,133,539
11	Annualized Labor @ 6/30/14	(Line 8 + Line 9 + Line 10)	39,673,031
12	Annualized Labor @ 5/31/13	Sch.1, Pg. 5, Ln.1	38,210,555
13	Adjustment	(Line 11 less Line 12)	1,462,476
14	O&M Expense Percentage	Sch.1, Pg 2, Ln. 8	66.1600%
15	O&M Payroll Adjustment Existing Employees	(Line 13 times Line 14)	967,574

Columbia Gas of Pennsylvania, Inc.
Calculation of Wage Increase
FTY = Future Test Year TME 5/31/13, FFRY = Fully Forecasted Rate Year Period Ended June 30, 2014
FTY Adjustment

Line No.	Description	Reference	Clerical	Exempt	Manual Non-Union	Local 1852-17 Union	Local 12124 & Local 13787 Union	Local 475 Union	Local 479 Union	Affiliate Labor Transferred	Overtime Premium	Total
			(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10= 1 thur 9)
			$	$	$	$	$	$	$	$	$	$
1	Annualized Labor @ 5/31/12	Exh. No.4, Sch.2, Page 4	2,796,076	6,487,059	681,138	4,380,154	6,565,125	7,655,475	3,633,248	0		32,198,276
2	Historic Test Year Level Labor	Exh. No.4, Sch.2, Page 5, Line 13, Col 7								1,136,126		1,136,126
3	Subtotal Annualized Labor @ 5/31/12	Line 1 + Line 2	2,796,076	6,487,059	681,138	4,380,154	6,565,125	7,655,475	3,633,248	1,136,126	0	33,334,401
4	Overtime & Premium @ Twelve Months Ended 5/31/12	Exh. No. 4, Sch.2, Page 5, Ln 13, Col 5 & 6									4,036,479	4,036,479
5	Adjusted Annualized Labor @5/31/12 (Lines 1 thru 4)	Line 3 + Line 4	2,796,076	6,487,059	681,138	4,380,154	6,565,125	7,655,475	3,633,248	1,136,126	4,036,479	37,370,880
6	Percent Increase for FTY [1]		2.50%	3.00%	2.50%	2.00%	2.00%	2.00%	2.00%	n/a	2.00%	
7	Amount of Increase	Line 5 x Line 6	69,902	194,612	17,028	87,603	131,303	153,110	72,665	32,722 [2]	80,730	839,875
8	Subtotal	Line 5 + line 7	2,865,978	6,681,671	698,166	4,467,757	6,696,428	7,808,585	3,705,913	1,168,848	4,117,209	38,210,555
9	Percent Increase at (No Longer Applicable to FTY)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%	
10	Amount of Increase	Line 8 x Line 9	0	0	0	0	0	0	0	0	0	0
11	Total Adjusted Annualized Labor at 05/31/13	Line 8 + Line 10	2,865,978	6,681,671	698,166	4,467,757	6,696,428	7,808,585	3,705,913	1,168,848	4,117,209	38,210,555

[1] Increases are as follows:
Clerical, Exempt & Manual - 6/1/12
Local 1852-17 - 4/1/13
Local 12124 & Local 13787 - 9/15/12
Local 475 - 9/30/12
Local 479 - 11/1/12
Affiliates - See Schedule 6, Premium/Overtime - used Union Increase

[2] Schedule 6

Columbia Gas of Pennsylvania, Inc.
Calculation of Wage Increase
FTY = Future Test Year TME 5/31/13, FFRY = Fully Forecasted Rate Year Period Ended June 30, 2014
FFRY Adjustment

Line No.	Description	Reference	Clerical (1) $	Exempt (2) $	Manual Non-Union (3) $	Local 1852-17 Union (4) $	Local 12124 & Local 13787 Union (5) $	Local 475 Union (6) $	Local 479 Union (7) $	Affiliate Labor Transferred (8) $	Overtime Premium (9) $	Total (10= 1 thru 9) $
1	Adjusted Annualized Labor @ 5/31/13	Sch.1, Page 4, Line 11	2,865,978	6,681,671	698,166	4,467,757	6,696,428	7,808,585	3,705,913	1,168,848	4,117,209	38,210,555
2	Percent Increase at 6/1/13		2.50%	3.00%	2.50%	0.00%	0.00%	0.00%	0.00%	Various	0.00%	
3	Amount of Increase	Line 1 x Line 2	71,649	200,450	17,454	0	0	0	0	39,384 [2]	0	328,937
4	Total Annualized Labor at 6/30/14	Line 1 + Line 3	2,937,627	6,882,121	715,620	4,467,757	6,696,428	7,808,585	3,705,913	1,208,232	4,117,209	38,539,492
5	Percent Increase for FFRY [1]		2.50%	3.00%	2.50%	3.00%	3.00%	3.00%	3.00%	Various	3.00%	
6	Amount of Increase		73,441	206,464	17,891	134,033	200,893	234,258	111,177	31,866 [3]	123,516	1,133,539
7	Total Annualized Labor at 6/30/14		3,011,068	7,088,585	733,511	4,601,790	6,897,321	8,042,843	3,817,090	1,240,098	4,240,725	39,673,031

[1] Increases are as follows:
Clerical, Exempt & Manual - 6/1/14
Local 1852-17 - 4/1/14
Local 12124 & Local 13787 - 9/15/13
Local 475 - 9/30/13
Local 479 - 11/1/13
Affiliates - See Schedule 6, Premium/Overtime - used Union Increase

[2] See Schedule 6

[3] See Schedule 6

8		Portion of Fully Forecasted Rate Year Adjustment expected to be incurred in Rate Year										
9		Jul-13	5,971	16,704	1,455					3,282		27,411
10		Aug-13	5,971	16,704	1,455					3,282		27,411
11		Sep-13	5,971	16,704	1,455		8,371			3,282		35,782
12		Oct-13	5,971	16,704	1,455		16,741	19,522		3,282		63,674
13		Nov-13	5,971	16,704	1,455		16,741	19,522	9,265	3,282		72,939
14		Dec-13	5,971	16,704	1,455		16,741	19,522	9,265	3,282		72,939
15		Jan-14	5,971	16,704	1,455		16,741	19,522	9,265	5,938	10,293	85,887
16		Feb-14	5,971	16,704	1,455		16,741	19,522	9,265	5,938	10,293	85,887
17		Mar-14	5,971	16,704	1,455		16,741	19,522	9,265	5,938	10,293	85,887
18		Apr-14	5,971	16,704	1,455	11,169	16,741	19,522	9,265	5,938	10,293	97,057
19		May-14	5,971	16,704	1,455	11,169	16,741	19,522	9,265	5,938	10,293	97,057
20		Jun-14	12,091	33,910	2,945	11,169	16,741	19,522	9,265	5,938	10,293	121,873
21	Gross Payroll Impact in Rate Year		77,769	217,855	18,945	33,508	159,040	175,694	74,118 [2]	55,317 [2]	61,758	873,805
22	Capitalization											66.16%
23	O&M Impact in Rate Year											578,109

Annual pay increases for employees in columns 1, 2, 3, 4, 5, 6 and 7 are reflected based on the dates as provided in footnote [1].
Affiliate labor Line 3 is included in its entirety. Affiliated labor and premium/overtime Line 6 is assumed to be a mid-period increase.

Ln. No.	Description	Per Response to I&E-RE-42-D: Net Transfers $	Percent of Total	FTY 2012 Increase Percent	FTY 2012 Increase $	Subtotal Adjusted FTY $	6/1/2013 Increase Percent	6/1/2013 Increase $	Adjusted FTY $	FFRY Increase Percent	Total Increase $	Adjusted FFRY $
	(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)
1	Exempt	583,014	51%	3.00%	17,490	600,504	3.00%	18,015	618,520	3.00%	18,556	637,075
2	Clerical	733,837	65%	2.50%	18,346	752,183	2.50%	18,805	770,987	2.50%	19,275	790,262
3	Manual - Non Union	100,068	9%	2.50%	2,502	102,570	2.50%	2,564	105,134	2.50%	2,628	107,762
4	Manual - Union (1)	(280,793)	-25%	2.00%	(5,616)	(286,409)	0.00%	-	(286,409)	3.00%	(8,592)	(295,001)
5	Total	1,136,126	100%		32,722	1,168,848		39,384	1,208,232		31,866	1,240,098
6	Amount of Increase per Exh. 104 Sch. 2 , Pages 2&3				(22,723)			(34,765)			0	
7	Adjustment				9,999			4,619			31,866	46,484

(1) Please see the response to I&E-RE-37-D for the use of 3.00% for determining the Manual - Union FFRY adjustment.

Line No.		Reference	
1	Normalized Labor TME: May 31, 2012	Exhibit No. 104, Sch 1, Page 2, Ln 1	25,335,318
2	O&M Expense Percentage - May 31, 2012		67.4700%
3	Gross Labor TME: May 31, 2012		37,550,494
4	O&M Expense Percentage - 5 Year Average 2008 - 2012	Schedule 1, Page 2, Ln 8	66.1600%
5	Adjusted Normalized Labor TME: May 31, 2012		24,843,407
6	Difference	Line 1 - Line 5	(491,911)

Exhibit No. 104

Columbia Gas of Pennsylvania, Inc..
Incentive Compensation
FTY = Future Test Year TME 5/31/13, FFRY = Fully Forecasted Rate Year Period Ended June 30, 2014

Line No.		Reference	Amount $
	FTY Adjustment		
1	Estimated 2013 Incentive - Target Level	Line 1 + Line 3	1,988,358
2	Percent to O&M Expense	Sch 1, Pg 2, Ln 8	66.1600%
3	Incentive Compensation included in O&M	Line 1 x Line 2	1,315,498
4	Annualized Historic Test Year Level	Exh. 104, Sch 1. Pg 2, Ln 2	1,607,482
5	Total Adjustment	Line 3 - Line 4	(291,984)
	FFRY Adjustment		
6	Estimated 2014 Incentive - Target Level	Exh. 104, Sch 2. Pg 4, Ln 6	2,047,906
7	Percent to O&M Expense	Sch 1, Pg 2, Ln 8	66.1600%
8	Incentive Compensation Included in O&M	Line 6 x Line 7	1,354,895
9	Incentive Compensation Included in FTY O&M	Line 3	1,315,498
10	Total Adjustment	Line 8 - Line 9	39,397

11	**Portion of Fully Forecasted Rate Year Adjustment Expected to be Incurred in Rate Year**		
12		Jul-13	0
13		Aug-13	0
14		Sep-13	0
15		Oct-13	0
16		Nov-13	0
17		Dec-13	0
18	Reflects total adjustment (Line 10) divided by 12 months	Jan-14	3,348
19		Feb-14	3,348
20		Mar-14	3,348
21		Apr-14	3,348
22		May-14	3,348
23		Jun-14	3,348
24		O&M for Rate Year	20,088
	The 2014 Incentive would be reflected in the rate year expense starting in January 2014.		

Columbia Gas of Pennsylvania, Inc.
FTY = Future Test Year TME 5/31/13, FFRY = Fully Forcasted Rate Year Period Ended June 30, 2014
FTY Adjustment - Annualization of Change In Benefits Expense

Line No.	Cost Element No.	Description	05/31/12 Gross Per Books (1) $	05/31/12 Per Books Total Transfers (2) $	05/31/12 Test Year Net Costs (3 =1 - 2) $	2013 Gross Costs 1 / (4) $	2013 Total Transfers (5 = 4 x -7) $	2013 Net Costs Before Adj (6 = 4 -5) $	Percent Capitalized 4 / (7) %	Average per (510) Employee (8 = 6/510) $	Capitalization 34.49% Additional Cost For New Employees 55 (9 = 8 x 55 x capitalization)	2013 Net Costs (11 = 6 + 9) $	Net Adjustment (12 = 11 - 3) $
		PENSIONS AND RETIREMENT INCOME											
1	9061	Retirement Income Plan	15,020,000	(6,996,688)	8,023,312	9,975,667 2/	(3,375,766)	6,599,901	33.84%	N/A	N/A	6,599,901	(1,423,411)
2	9061	Supplemental Retirement Income Plan	5,882	(2,277)	3,605	3,000	(1,015)	1,985	33.84%	N/A	N/A	1,985	(1,620)
3		Total Pensions and Retirement Income	15,025,882	(6,998,965)	8,026,917	9,978,667	(3,376,781)	6,601,886				6,601,886	(1,425,031)
		OPEB COST											
4	9046	Ongoing OPEB - Medical	(78,124)	28,121	(50,003)	0	0	0	33.84%	N/A	N/A	0	50,003
5	9047	Ongoing OPEB - Group Life	67,287	(24,221)	43,066	0	0	0	33.84%	N/A	N/A	0	(43,066)
6	9048	SFAS 106 Amortization	1,541,956	0	1,541,956	0	0	0		N/A	N/A	0	(1,541,956)
7		Total OPEB Deferral	1,531,119	3,900	1,535,019	0	0	0		0	0	0	(1,535,019)
8	9049	SFAS 112	(432,627)	0	(432,627)	138,824	0	138,824		N/A	N/A	138,824	571,451
9		OPEB difference between expense and recovery		469,574	469,574	0	0	0		N/A	N/A	0	(469,574)
10		OPEB Overcollection Post Rate Case	0	0	0	0	0	(303,697)		N/A	N/A	(303,697)	(303,697)
11		Total OPEB (Line 7 + Line 8 + Line 9 + Line 10)	1,098,492	473,474	1,571,966	138,824	0	(164,873)		0	0	(164,873)	(1,736,839)
		EMPLOYEES' INSURANCE PLANS & OTHER											
12	904189045	Comp Medical Insurance and EAP	4,034,327	(1,452,189)	2,582,138	4,201,000	(1,421,618)	2,779,382	33.84%	8,237	156,267	2,935,649	353,511
13	9042	Dental Assistance	267,366	(96,241)	171,125	309,000	(104,566)	204,434	33.84%	606	11,494	215,926	44,803
14	9043	Group Life Insurance	108,842	(39,179)	69,663	114,000	(38,578)	75,422	33.84%	224	4,241	79,663	10,000
15	9044	Long Term Disability	281,233	(101,232)	180,001	289,000	(97,798)	191,202	33.84%	567	10,750	201,952	21,951
16		Total Employees' Insurance Plans	4,691,768	(1,688,841)	3,002,927	4,913,000	(1,662,560)	3,250,440		9,633	182,752	3,433,192	430,265
17	9081	Thrift Plan	1,481,491	(549,667)	931,824	1,727,000	(584,417)	1,142,583	33.84%	3,386	64,240	1,206,823	274,999
18	*9095*	*Profit Sharing* 3/	341,334	0	341,334	315,000	(106,596)	208,404	33.84%	618	11,717	220,121	(121,213)
19		Inter-Company Billing	112,071	(40,341)	71,730	112,071	(37,925)	74,146	33.84%	0	0	74,146	2,416
20		Total Employees' Insurance Plans and Other	6,626,664	(2,278,849)	4,347,815	7,067,071	(2,391,498)	4,675,573		13,637	258,709	4,934,282	586,467
21		Total (Line 3 + Line 11 + Line 20)	22,751,038	(8,804,340)	13,946,698	17,184,562	(5,768,279)	11,112,586		13,637	258,709	11,371,295	(2,575,403)

_/1 Per Hewitt Estimates as of 8-2012
_/2 Reflects 3 year average of contributions (8/10 - $332,000, 9/10 - $7,337,000, 10/10 - $782,000, 12/10 - $782,000, 3/11 - $4,652,000, 4/11 - $1,022,000,7/11 - $964,000, 9/11 - $964,000 and 12/11 - $13,092,000)
_/3 Profit sharing recorded net of capital in gross expense
_/4 Capitalization Rate of 33.84% calculated on Schedule 1, Page 2

Columbia Gas of Pennsylvania, Inc.
FTY = Future Test Year TME 5/31/13, FFRY = Fully Forcasted Rate Year Period Ended June 30, 2014
Annualization of Increase in Benefits Expense
FFRY Adjustment - Annualization of Change in Benefits Expense

Line No.	Cost Element No.	Description	FTY Net Costs (1) $	2013 Gross Costs 1 / (2) $	2013 Total Transfers (3 = 2 x -5) $	2013 Net Costs Before Adj (4 = 2 - 3) $	Percent Capitalized 4 / (5) %	Average per (510) Employee (6 = 6/510) $	Capitalization 34.49% Additional Cost For New Employees 55 (7 = 6 x 55) $	2014 Net Costs (8 = 4 + 7) $	Net Adjustment (9 = 8 - 1) $
		PENSIONS AND RETIREMENT INCOME									
1	9061	Retirement Income Plan	6,599,901	5,548,167 2 /	(1,877,500)	3,670,667	33.84%	N/A	N/A	3,670,667	(2,929,234)
2	9061	Supplemental Retirement Income Plan	1,985	5,000	(1,683)	3,317	33.84%	N/A	N/A	3,317	1,332
3		Total Pensions and Retirement Income	6,601,886	5,553,167	(1,879,183)	3,673,984				3,673,984	(2,927,902)
		OPEB COST									
4	9046	Ongoing OPEB - Medical	0	0	0	0	33.84%	N/A	N/A	0	0
5	9047	Ongoing OPEB - Group Life	0	0	0	0	33.84%	N/A	N/A	0	0
6	9048	SFAS 106 Amortization	0	0	0	0		N/A	N/A	0	0
7		Total OPEB Deferral	0	0	0	0		0	0	0	0
8	9049	SFAS 112	138,824	138,824	0	138,824		N/A	N/A	138,824	0
9		OPEB difference between expense and recovery	0	0	0	0		N/A	N/A	0	0
10		OPEB Overcollection Post Rate Case	(303,697)	0	0	(303,697)		N/A	N/A	(303,697)	0
11		Total OPEB	(164,873)	138,824	0	(164,873)		0	0	(164,873)	0
		EMPLOYEES' INSURANCE PLANS & OTHER									
12	9041&9045	Comp Medical Insurance and EAP	2,935,649	4,583,000	(1,550,887)	3,032,113	33.84%	8,986	170,477	3,202,590	266,941
13	9042	Dental Assistance	215,928	323,000	(109,303)	213,697	33.84%	633	12,015	225,712	9,784
14	9043	Group Life Insurance	79,663	118,000	(39,931)	78,069	33.84%	231	4,389	82,458	2,795
15	9044	Long Term Disability	201,952	298,000	(100,843)	197,157	33.84%	584	11,085	208,242	6,290
16		Total Employees' Insurance Plans	3,433,192	5,322,000	(1,800,964)	3,521,036		10,435	197,966	3,719,002	285,810
17	9081	Thrift Plan	1,206,823	1,778,000	(601,675)	1,176,325	33.84%	3,486	66,137	1,242,462	35,639
18	9095	Profit Sharing 3 /	220,121	324,000	(109,642)	214,358	33.84%	635	12,052	226,410	6,289
19		Inter-Company Billing	74,146	112,071	(37,925)	74,146	33.84%	0	0	74,146	0
20		Total Employees' Insurance Plans and Other	4,934,282	7,536,071	(2,550,206)	4,985,865		14,557	276,155	5,262,020	327,738
21		Total (Line 3 + Line 11 + Line 20)	11,371,295	13,228,062	(4,429,389)	8,494,976		14,557	276,155	8,771,131	(2,600,164)

22 _/1 Per Hewitt Estimates as of 8-2012
23 _/2 Reflects 3 year average of contributions (7/11 - $984,000, 9/11 - $984,000, 12/11 - $13,092,000 and half of expected 2014 contribution of $3,249,000)
24 _/3 Profit sharing recorded net of capital in gross expense
25 _/4 Capitalization Rate of 33.84% calculated on Schedule 1, Page 2

26	**Portion of Fully Forecasted Rate Year Adjustment Expected to be Incurred in Rate Year**	Jul-13	0
27		Aug-13	0
28		Sep-13	0
29		Oct-13	0
30		Nov-13	0
31		Dec-13	0
32	Reflects Total Adjustment (Line 21) divided by 12 months.	Jan-13	(216,680)
33		Feb-13	(216,680)
34		Mar-13	(216,680)
35		Apr-13	(216,680)
36		May-13	(216,680)
37		Jun-13	(216,680)
38		Total	(1,300,080)

The 2014 benefit costs would be reflected in the rate year expense starting in January 2014.

Columbia Gas Pennsylvania, Inc.
Statement of Projected Taxes Other Than Income Taxes at Present Rates
Twelve Months Ended May 31, 2013

Line No.	Description	Normalized Normalized Twelve Months Ended May. 31 2012 $	Adjustments $	Normalized Normalized Twelve Months Ended May. 31 2013 $
1	FICA	2,007,947	59,529	2,067,475
2	Federal Unemployment	45,196	0	45,196
3	State Unemployment	161,920	0	161,920
4	Property Tax	642,142	(0)	642,142
5	Capital Stock	544,421	(288,053)	256,368
6	License and Franchise	6,251	0	6,251
7	Sales and Use	614,394	0	614,394
8	Other	32,056	(4,625)	27,431
9	Total Taxes Other Than Income Taxes	4,054,326	(233,150)	3,821,177

Columbia Gas Pennsylvania, Inc.
Statement of Projected Taxes Other Than Income Taxes at Present Rates
Twelve Months Ended June 30, 2014
"FFRY Schedule"

Line No.	Description	Normalized Twelve Months Ended May. 31 2013 $	Adjustments $	Normalized Twelve Months Ended June. 30 2014 $
1	FICA	2,067,475	79,037	2,146,512
2	Federal Unemployment	45,196	0	45,196
3	State Unemployment	161,920	0	161,920
4	Property Tax	642,142	(0)	642,141
5	Capital Stock	256,368	(256,368)	0
6	License and Franchise	6,251	0	6,251
7	Sales and Use	614,394	0	614,394
8	Other	27,431	0	27,431
9	Total Taxes Other Than Income Taxes	3,821,177	(177,331)	3,643,845

Columbia Gas Pennsylvania, Inc.
Taxes Other Than Income Taxes
To Annualized Increase In FICA Tax
Normalized Twelve Months Ended May 31, 2013

Line No.	Description	Taxable for Social Security (1) $	Taxable for Medicare (2) $	Total (3) $	Reference (4)
1	Percent of Total Taxable	99.17%	100.00%		I&E-RE-128-D
2	Tax Rates	6.20%	1.45%		
3	Payroll Adjustment [1] (Col 1 = Ln. 4, Col. 3 times Ln. 2, Col 1)	776,922	783,425	783,425	Exh. JTG-R2, Sch. 1, Pg. 1, Col. 2, Lns. 1, 1a, 2, 3
4	Payroll Tax Change (line 3 * line 4)	48,169	11,360	59,529	

Columbia Gas Pennsylvania, Inc.
Taxes Other Than Income Taxes
To Annualized Increase In FICA Tax
Normalized Twelve Months Ended June 30, 2014
"FFRY Schedule"

Line No.	Description	Taxable for Social Security (1) $	Taxable for Medicare (2) $	Total (3) $	Reference (4)
5	Percent of Total Taxable	99.17%	100.00%		I&E-RE-128-D
6	Tax Rates	6.20%	1.45%		
7	Payroll Adjustment [1] (Col 1 = Ln. 4, Col. 3 times Ln. 2, Col 1)	1,031,526	1,040,159	1,040,159	Exh. JTG-R2, Sch. 1, Pg. 1, Col. 5, Lns. 1, 2, 3
8	Payroll Tax Change (line 3 * line 4)	63,955	15,082	79,037	

Columbia Gas of Pennsylvania
Revised Revenue Claim
R-2012-2321748

Exhibit JTG-R2, Schedule 4, Page 1, Line 1, Col 9 reflects updated Exhibit 102	$	73,284,617
Exhibit JTG-R2, Schedule 5, Page 1, Line 20, Col 5		398,267
Total Revised Revenue Claim	$	73,682,884

Columbia Gas of Pennsylvania, Inc.
Statement of Income at Present and Proposed Rates
FTY = Future Test Year TME 6/31/13, FFRY = Fully Forecasted Rate Year Period Ended June 30, 2014

Line No.	Description	Reference for Column 2	Pro Forma Historic Test Year	FTY Adjustments @ Present Rates	Reference for Column 5	FTY Test Year	Reference for Column 7	FFRY Adjustments @ Present Rates	FFRY Test Year	Reference for Column 9	Adjustments	FFRY @ Proposed Rates
		(1)	(2)	(3)	(4)	(5=2+3)	(6)	(7)	(8=6+7)	(10)	(9)	(11=8+9)
			$	$		$		$	$		$	$
1	Operation Revenues											
2	Base Rate Revenues (Incl. Transportation)	Exhibit 102	212,908,870	1,776,824	Exhibit 102	214,685,494	Exhibit 102	307,442	214,992,936	Page 3	73,284,617	288,277,553
3	Fuel Revenues	Exhibit 102	148,223,679	1,188,693	Exhibit 102	149,412,372	Exhibit 102	786,255	150,198,627		0	150,198,627
4	Rider USP	Exhibit 102	10,805,272	110,899	Exhibit 102	10,916,171	Exhibit 102	(58,100)	10,858,071		0	10,858,071
5	Storage Interest	Exhibit 102	0	146,486	Exhibit 102	0	Exhibit 102	0	0		0	0
6	Unbundled Uncollectibles-Gas Cost	Exhibit 102	1,817,075	106,765	Exhibit 102	1,925,840	Exhibit 102	(77,564)	1,848,276		0	1,848,276
7	Off System Sales Revenue	Exhibit 102	0	0	Exhibit 102	0	I&E-RS-41-D (cust attrition)	168,345	168,345		0	168,345
8	Late Payment Fees	Exhibit 102	934,013	7,960	Exhibit 102	941,973	I&E-RE-25-D	198,022	1,137,995		0	1,137,995
9	Other Operating Revenues (Excl. Transportation)	Exhibit 102	464,423	0	Exhibit 102	464,423	Exhibit 102	0	464,423		0	464,423
10	Total Operating Revenues		375,153,332	3,339,427		378,346,273		1,322,400	379,668,673		73,284,617	452,953,290
						0						
11	Operating Revenue Deductions											
12	Gas Supply Expense	Exhibit 102	148,223,679	1,188,693	Exhibit 102	149,412,372	Exhibit 102	786,255	150,198,627		0	150,198,627
13	Off System Sales Expense	Exhibit 102	0	0	Exhibit 102	0	Exhibit 102	0	0		0	0
14	Gas Used in Company Operations		0	0		0		0	0		0	0
15	Operating and Maintenance Expense	Exhibit 102	125,484,092	4,283,349	Exh. JTG-R2, Sch. 1, Pg 1	129,767,441	Exh. JTG-R2, Sch. 1, Pg 1	6,139,411	135,906,852	Page 3	1,068,490	136,975,341
16	Depreciation and Amortization	Exhibit 102	28,335,103	4,003,098		32,338,201	Exh. JJS-5R Pg 3 Col 6	4,197,081	36,535,282		0	36,535,282
17	Net Salvage Amortized	Exhibit 102	4,409,745	261,437	Exhibit 102	4,671,182	Exh. JTG-R2 Pg 7	193,149	4,864,331		0	4,864,331
18	Taxes Other Than Income Taxes	Exhibit 102	4,054,328	(233,150)	Exh. JTG-R2, Sch. 2, Pg 1	3,821,177	Exh. JTG-R2, Sch. 2, Pg 1	(177,331)	3,643,846		0	3,643,846
19	Total Operating Revenue Deductions		310,506,945	9,503,427		320,010,372		11,138,565	331,148,937		1,068,490	332,217,427
20	Operating Income Before Income Taxes		64,646,387	(6,164,000)		58,335,901		(9,816,165)	48,519,736	Page 4	72,216,127	120,735,863
21	Income Taxes	Exhibit 102	6,176,268		Exh. No. 107, Pg 16, Col 2, Ln 43	982,781	Exh. No. 107, Pg 16, Col 3, Ln 43	6,067,897	7,050,678	Exh. No. 107, Pg 16, Col 4, Ln 43	29,198,220	36,228,898
22	Investment Tax Credit	Exhibit 102	(360,239)		Exhibit 102	(360,239)		0	(360,239)		0	(360,239)
23	Operating Income		59,830,358			57,733,359		(15,884,062)	41,849,297	Page 4	43,017,907	84,867,204
24	Rate Base	Exhibit 102	800,331,300		Exh. NJDK-3R Col 3, Ln 23	866,694,369	Exh. NJDK-3R Col 5, Ln 23	0	996,093,941		0	996,093,941
25	% Rate of Return Earned on Rate Base		7.476%			6.570%			4.201%			8.520%

Columbia Gas of Pennsylvania, Inc.
Calculation of Proforma Interest Expense
Twelve Months Ended May 31, 2013

Line No.	Description	Pro Forma (2) $
	FTY Calculation	
1	Rate Base	865,594,369
2	Weighted Cost of Short &	
3	Long Term Debt	2.630%
4	Interest Expense	22,765,132
	FFRY Calculation	
5	Rate Base	996,093,941
6	Weighted Cost of Short &	
7	Long Term Debt	2.6300%
8	Interest Expense	26,197,271

Columbia Gas of Pennsylvania, Inc.
Rate of Return on Rate Base
Proposed Revenue Requirement

Line No.	Acct. No.	Description	Detail	Amount
				(1) $
1		Proforma Rate Base at Present Rates		996,093,941
2		Return on Rate Base		8.520%
3		Total Requirement		84,867,204
4		Less: Net Operating Income at Present Rates		41,849,297
5		Net Required		43,017,907
6		Revenue Conversion Factor		1.70358398
7		Gross Revenue Requirement		73,284,617
8		Revenue Conversion Factor:		
9		Operating Revenue		1.00000000
10		Less: Uncollectibles		0.01458000
14		Income Before State Taxes		0.98542000
15		Less: State Income Tax @ Effect Tax Rate		0.08234650
16		Income Before Federal Taxes		0.90307350
17		Less: Federal Tax @ 35%		0.31607573
18		Adjusted Operating Income		0.58699777
19		Revenue Conversion Factor		1.70358398
20		Uncollectible Fees on Gross Revenue Requirement		1,068,490

Columbia Gas of Pennsylvania, Inc.
Additional Revenue Requirement Adjustments
Twelve Months Ended May 31, 2013

Line No.	Acct. No.	Description	Amount
			(2) $
1		Additional Revenue Requirement	73,284,617
2		Operating & Maintenance Expense	
3	Less:	Uncollectible Accounts Expense	
4		Line 1 X Uncollectible Rate	1,068,490
5		Income Before State Income Tax	72,216,127
6		State Income Taxes	
7		Line 11 Times Effect Tax Rate (9.99%)	7,214,391
8		Income Before Federal Income Tax	65,001,736
9		Federal Income Taxes	
10		Line 14 Times 35%	22,750,608
11		Operating Income	42,251,129

Columbia Gas of Pennsylvania, Inc
Summary Cost of Capital
As of May 31, 2012

Type of Capital	Ratios %	Cost Rate %	Weighted Cost %
Long Term Debt	44.11%	5.81%	2.56000%
Short Term Debt	3.57%	1.90%	0.07000%
Total Debt	47.68%	5.52%	2.63000%
Common Equity	52.32%	11.25%	5.8900%
Total	100.00%		8.52%

Columbia Gas of Pennsylvania
Additional $3.2 Million Capital Spend

Line No.	(1)	(2)	(3) Reference	(4)	(5)
1	Rate Base				
2		Account 101	Pg 2, Ln 7, Col 14	3,200,000	
3		Account 108	Pg 2, Ln 18, Col 14	(52,767)	
4		Deferred Taxes	Tax calculation	(115,000)	
5					
6		Net Rate Base		3,032,233	
7					
8					
9	Revenue Requirement				
10					
11		Return	Ln 6 * 8.52%	258,346	
12		Tax Expense Change	Tax calculation	(65,849)	
13		Subtotal		192,497	
14		Revenue Conversion Factor	Exhibit JTG2-R, Schedule 4, Page 3, Line 19	1.70358398	
15					
16		Revenue Impact	Ln 13 * Ln 14		327,935
17					
18		Depreciation	Pg 2, Ln 16,Col 14 * 12		70,332
19					
20	Total Revenue Revenue Requirement				398,267

Columbia Gas of Pennsylvania
Additional $3.2 Million Capital Spend

Line No.	(1) Account	(2) Description	(3) Jul-13	(4) Aug-13	(5) Sep-13	(6) Oct-13	(7) Nov-13	(8) Dec-13	(9) Jan-14	(10) Feb-14	(11) Mar-14	(12) Apr-14	(13) May-14	(14) Jun-14	(15) Total
1	GPA -367	557 Mains - Leakage Elim	379,000	379,000	379,000	379,000	378,000	378,000	-	-	-	-	-	-	2,272,000
2	GPA - 380	565 Service Lines - Replaced	155,000	155,000	155,000	155,000	154,000	154,000	-	-	-	-	-	-	928,000
3		Total	534,000	534,000	534,000	534,000	532,000	532,000	-	-	-	-	-	-	3,200,000
4															
5		557 Cumulative spend	379,000	758,000	1,137,000	1,516,000	1,894,000	2,272,000	2,272,000	2,272,000	2,272,000	2,272,000	2,272,000	2,272,000	
6		565 Cumulative spend	155,000	310,000	465,000	620,000	774,000	928,000	928,000	928,000	928,000	928,000	928,000	928,000	
7	101	Account 101 Balance by Month	534,000	1,068,000	1,602,000	2,136,000	2,668,000	3,200,000	3,200,000	3,200,000	3,200,000	3,200,000	3,200,000	3,200,000	
8															
9		557 Depr rate	1.960%	1.960%	1.960%	1.960%	1.960%	1.960%	1.960%	1.960%	1.960%	1.960%	1.960%	1.960%	
10		565 depr rate	2.780%	2.780%	2.780%	2.780%	2.780%	2.780%	2.780%	2.780%	2.780%	2.780%	2.780%	2.780%	
11															
12		current month 557 Dep (1/2 month)	310	310	310	310	309	309	-	-	-	-	-	-	
13		current month 565 Dep (1/2 month)	180	180	180	180	178	178	-	-	-	-	-	-	
14		current month 557 dep all activity prior	-	619	1,238	1,857	2,476	3,094	3,711	3,711	3,711	3,711	3,711	3,711	
15		current month 565 dep all activity prior	-	359	718	1,077	1,436	1,793	2,150	2,150	2,150	2,150	2,150	2,150	
16		Depreciation expense	490	1,468	2,446	3,424	4,399	5,374	5,861	5,861	5,861	5,861	5,861	5,861	
17															
18	108	Accumulated Depreciation	490	1,958	4,404	7,828	12,227	17,601	23,462	29,323	35,184	41,045	46,906	52,767	

Columbia Gas of Pennsylvania, Inc.
Comparison of Revenues at Current and Proposed Rates
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1) *(Ex 103, Sch 1)*	Volumes (2) Dth *(Ex 103, Sch 1)*	Revenue @ Current Rates (3) $ *(Ex 103, Sch 1)*	Proposed Adjustment (4) = (5) - (3) $	Revenue @ Proposed Rates (5) $ *(Ex 103, Sch 8)*
1	**Rate Schedule RSS - Residential Sales Service**					
2	Residential	3,574,045	23,110,026.2	222,094,385	48,182,269	270,276,654
3	**Rate Schedule PRDGSS - Pilot Residential Distributed Generation Sales Service**					
4	Residential	295	2,761.8	24,514	5,275	29,789
5	**Rate Schedule SGSS - Small General Sales Service (< 64,380 Therms Annually)**					
6	Commercial	317,234	8,086,967.1	59,018,457	9,265,563	68,284,020
7	Industrial	710	126,957.1	838,535	102,924	941,459
8	Total Rate Schedule SGSS	317,944	8,213,924.2	59,856,992	9,368,487	69,225,479
9	**Rate Schedule NSS - Negotiated Sales Service**					
10	Commercial	12	61,000.0	271,094	901	271,995
11	**Rate Schedule NSS - Negotiated Sales Service**					
12	Industrial	0	0.0	0	0	0
13	**Rate Schedule LGSS - Large General Sales Service**					
14	Commercial	848	829,441.6	4,973,829	518,069	5,491,898
15	Industrial	97	102,042.7	613,618	64,020	677,638
16	Total Rate Schedule LGSS	945	931,484.3	5,587,447	582,089	6,169,536
17	**Tariff Sales Summary by Customer Class**					
18	Total Residential Sales	3,574,340	23,112,788	222,118,899	48,187,544	270,306,443
19	Total Commercial Sales	318,094	8,977,409	64,263,380	9,784,533	74,047,913
20	Total Industrial Sales	807	229,000	1,452,153	166,944	1,619,097
21	Total Tariff Sales	3,893,241	32,319,196.5	287,834,432	58,139,021	345,973,453

Columbia Gas of Pennsylvania, Inc.
Comparison of Revenues at Current and Proposed Rates
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1) (Ex 103, Sch 1)	Volumes (2) Dth (Ex 103, Sch 1)	Revenue @ Current Rates (3) $ (Ex 103, Sch 1)	Proposed Adjustment (4) = (5) - (3) $	Revenue @ Proposed Rates (5) $ (Ex 103, Sch 8)
1	**Rate Schedule RDS - Residential Distribution Service (Choice)**					
2	Residential	813,396	7,089,719.1	38,978,387	13,592,944	52,571,331
3	**Residential Distribution Service (CAP - Before Discount)**					
4	Residential	224,703	2,582,529.5	12,251,061	0	12,251,061
5	**Rate Schedule PRDGDS - Pilot Residential Distributed Generation Distribution Service (Choice)**					
6	Residential	60	751.2	3,752	1,321	5,073
7	**Rate Schedule SCD - Small Commercial Distribution (Choice)**					
8	Commercial	96,159	1,486,997.4	6,355,797	2,043,257	8,399,054
9	**Rate Schedule SGDS - Small General Distribution Service**					
10	Commercial	25,113	3,559,158.8	8,859,971	2,879,869	11,739,840
11	Industrial	430	83,369.6	181,728	64,333	246,061
12	Total Rate Schedule SGDS	25,543	3,642,528.4	9,041,699	2,944,202	11,985,901
13	**Rate Schedule SDS - Small Distribution Service**					
14	Commercial	3,784	4,185,627.1	5,786,846	366,561	6,153,407
15	Industrial	1,244	2,837,531.4	3,733,483	215,127	3,948,610
16	Total Rate Schedule SDS	5,028	7,023,158.5	9,520,329	581,688	10,102,017
17	**Rate Schedule LDS - Large Distribution Service**					
18	Commercial	266	2,825,143.2	2,672,811	2,961	2,675,772
19	Industrial	835	14,963,198.8	10,178,037	8,050	10,186,087
20	Total Rate Schedule LDS	1,101	17,788,342.0	12,850,848	11,011	12,861,859
21	**Rate Schedule MLDS - Main Line Distribution Service - Class I**					
22	Commercial	12	102,100.0	23,307	27	23,334
23	Industrial	36	3,076,300.0	405,683	47	405,730
24	Total Rate Schedule MLSS - Class I	48	3,178,400.0	428,990	74	429,064
25	**Rate Schedule MLDS - Main Line Distribution Service - Class II**					
26	Industrial	60	1,980,000.0	800,960	182	801,142
27	**Transportation Summary by Customer Class**					
28	Total Residential Transportation	1,038,159	9,673,000	51,233,200	13,594,285	64,827,485
29	Total Commercial Transportation	125,334	12,159,026.5	23,698,732	5,292,675	28,991,407
30	Total Industrial Transportation	2,605	22,940,399.8	15,299,891	287,739	15,587,630
31	Total Transportation	1,166,098	44,772,426.1	90,231,823	19,174,679	109,406,502

Columbia Gas of Pennsylvania, Inc.
Comparison of Revenues at Current and Proposed Rates
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1) (Ex 103, Sch 1)	Volumes (2) Dth (Ex 103, Sch 1)	Revenue @ Current Rates (3) $ (Ex 103, Sch 1)	Proposed Adjustment (4) = (5) - (3) $	Revenue @ Proposed Rates (5) $ (Ex 103, Sch 8)
1	**Total Company Throughput by Customer Class**					
2	Total Residential	4,612,499	32,785,787.8	273,352,099	61,781,809	335,133,908
3	Total Commercial	443,428	21,136,435.2	87,962,112	15,077,208	103,039,320
4	Total Industrial	3,412	23,169,399.6	16,752,044	454,683	17,206,727
5	Total Throughput	5,059,339	77,091,622.6	378,066,255	77,313,700	455,379,955
6	**Other Operating Revenue**					
7	487 - Forfeited Discounts			1,137,995	(193,628)	944,367
8	488 - Miscellaneous Service Revenues			146,687	0	146,687
9	493 - Rent from Gas Property			173,011	0	173,011
10	495 - Prior Yr. Rate Refund - Net.			0	0	0
11	495 - Off System Sales			0	0	0
12	495 - Other Gas Revenues - Other			144,725	0	144,725
13	496 - Provision For Rate Refunds			0	0	0
14	**Total Other Operating Revenue**			1,602,418	(193,628)	1,408,790
15	**Total Company Revenue**			379,668,673	77,120,072	456,788,745

Columbia Gas of Pennsylvania, Inc.
Dth and Revenue Summary [illegible]ent Rates
For the 12 Months Ended [illegible]0, 2014

Line No.	Acct No	Description	Per Proforma Historic Test Year (1)	Proforma Historic Test Year Gas Cost (2) (Ex 103, Sch 8)	Proforma Historic Rider USP (3) (Ex 3, Sch 9)	Proforma Historic Storage Interest (4) (Ex 3, Sch 9)	Proforma Historic Unbundled Uncollectibles (5) (Ex 3, Sch 9)	Adjustment To Reflect Annualization (9=10-(1-8)) $	Annualized Base Revenue (10) $ (Ex 103, Sch 1)
1		**GAS SERVICE REVENUE**							
2	480	Residential Sales Revenue	222,724,796	(100,453,031)	(8,357,138)	0	(1,429,663)	86,254	112,571,218
3	481	Commercial Sales Revenue	63,279,771	(38,080,252)	0	0	(488,405)	293,925	25,005,039
4	481	Industrial Sales Revenue	1,452,023	(989,553)	0	0	(7,772)	411	455,109
5	495	Unbilled Revenue	0	0	0	0	0	0	0
6	481	Other Sales Revenue [1]	0	0	0	0	0	0	0
7		**TOTAL GAS SERVICE REV**	287,456,590	(139,522,836)	(8,357,138)	0	(1,925,840)	380,590	138,031,366
8	487	Forfeited Discounts	941,973	0	0	0	0	196,022	1,137,995
9	488	Miscellaneous Service Rev	146,687	0	0	0	0	0	146,687
10	489	Transportation of Gas	89,483,287	(9,889,536)	(2,559,033)	0	0	95,197	77,129,915
11	489	Trans of Gas - Unbilled	0	0	0	0	0	0	0
12	493	Rent from Gas Property	173,011	0	0	0	0	0	173,011
13	495	Prior Yr. Rate Refund - Net	0	0	0	0	0	0	0
14	495	Off System Sales	0	0	0	0	0	0	0
15	495	Unbilled Off System Sales	0	0	0	0	0	0	0
16	495	Other Gas Revenues - Other	144,725	0	0	0	0	0	144,725
17	496	Provision For Rate Refunds	0	0	0	0	0	0	0
18		**TOTAL OTHER OPER. REV**	90,889,683	(9,889,536)	(2,559,033)	0	0	291,219	78,732,333
19		**TOTAL REVENUE**	378,346,273	(149,412,372)	(10,916,171)	0	(1,925,840)	671,809	216,763,699
20		**SALES VOL (Dth) Phy. Flow**							
21		Residential Sales	23,072,000.0	0.0	0.0	0.0	0.0	40,788.0	23,112,788.0
22		Commercial Sales	9,035,998.7	0.0	0.0	0.0	0.0	(58,590.0)	8,977,408.7
23		Industrial Sales	228,999.8	0.0	0.0	0.0	0.0	0.0	228,999.8
24		Unbilled Sales	0.0	0.0	0.0	0.0	0.0	0.0	0.0
25		Other Sales [1]	0.0	0.0	0.0	0.0	0.0	0.0	0.0
26		**TOTAL GAS SERVICE SALES**	32,336,998.5	0.0	0.0	0.0	0.0	(17,802.0)	32,319,196.5
27		**TRANSPORTATION VOL (Dth) Phy. Flow**							
28		Residential Transportation	9,672,999.8	0.0	0.0	0.0	0.0	0.0	9,672,999.8
29		Commercial Transportation	12,159,026.5	0.0	0.0	0.0	0.0	0.0	12,159,026.5
30		Industrial Transportation	23,050,399.8	0.0	0.0	0.0	0.0	(110,000.0)	22,940,399.8
31		Unbilled Transportation	0.0	0.0	0.0	0.0	0.0	0.0	0.0
32		**TOTAL TRANS VOLUME**	44,882,426.1	0.0	0.0	0.0	0.0	(110,000.0)	44,772,426.1
33		**TOTAL THROUGHPUT**	77,219,424.6	0.0	0.0	0.0	0.0	(127,802.0)	77,091,622.6

[1] Included in Industrial.

Columbia Gas of Pennsylvania, Inc.
Dth and Revenue Summary @ Current Rates
For the 12 Months Ended June 30, 2014

Line No.	Acct No	Description	Annualized Base Revenue (1) $ (Exh 103 - Page 9)	Annualized Gas Cost (2) $ (Ex 103, Sch 1)	Annualized Rider USP (3) $ (Ex 103, Sch 1)	Annualized Storage Interest (4) $ (Ex 103, Sch 1)	Annualized Unbundled Uncollectibles (5) $ (Ex 103, Sch 1)	Annualized Revenue (6=1+2+3+4+5) $ (Ex 103, Sch 1)
1		GAS SERVICE REVENUE						
2	480	Residential Sales Revenue	112,571,218	99,874,979	8,309,047	0	1,363,655	222,118,899
3	481	Commercial Sales Revenue	25,005,039	38,781,210	0	0	477,131	64,263,380
4	481	Industrial Sales Revenue	455,109	989,554	0	0	7,490	1,452,153
5	495	Unbilled Revenue	0	0	0	0	0	0
6	481	Other Sales Revenue	0	0	0	0	0	0
7		TOTAL GAS SERVICE REV	138,031,366	139,645,743	8,309,047	0	1,848,276	287,834,432
8	487	Forfeited Discounts	1,137,995	0	0	0	0	1,137,995
9	488	Miscellaneous Service Revenues	146,687	0	0	0	0	146,687
10	489	Transportation of Gas	77,129,915	10,552,884	2,549,024	0	0	90,231,823
11	489	Trans of Gas - Unbilled	0	0	0	0	0	0
12	493	Rent from Gas Property	173,011	0	0	0	0	173,011
13	495	Prior Yr. Rate Refund - Net.	0	0	0	0	0	0
14	495	Off System Sales	0	0	0	0	0	0
15	495	Unbilled Off System Sales	0	0	0	0	0	0
16	495	Other Gas Revenues - Other	144,725	0	0	0	0	144,725
17	496	Provision For Rate Refunds	0	0	0	0	0	0
18		TOTAL OTHER OPER. REV	78,732,333	10,552,884	2,549,024	0	0	91,834,241
19		TOTAL REVENUE	216,763,699	150,198,627	10,858,071	0	1,848,276	379,668,673
20		SALES VOL (Dth)						
21		Residential Sales	23,112,788.0	0.0	0.0	0.0	0.0	23,112,788.0
22		Commercial Sales	8,977,408.7	0.0	0.0	0.0	0.0	8,977,408.7
23		Industrial Sales	228,999.8	0.0	0.0	0.0	0.0	228,999.8
24		Unbilled Sales	0.0	0.0	0.0	0.0	0.0	0.0
25		Other Sales	0.0	0.0	0.0	0.0	0.0	0.0
26		TOTAL GAS SERVICE SALES	32,319,196.5	0.0	0.0	0.0	0.0	32,319,196.5
27		TRANSPORTATION VOLUMES (Dth)						
28		Residential Transportation	9,672,999.8	0.0	0.0	0.0	0.0	9,672,999.8
29		Commercial Transportation	12,159,026.5	0.0	0.0	0.0	0.0	12,159,026.5
30		Industrial Transportation	22,940,399.8	0.0	0.0	0.0	0.0	22,940,399.8
31		Unbilled Transportation	0.0	0.0	0.0	0.0	0.0	0.0
32		TOTAL TRANS VOLUME	44,772,426.1	0.0	0.0	0.0	0.0	44,772,426.1
33		TOTAL THROUGHPUT	77,091,622.6	0.0	0.0	0.0	0.0	77,091,622.6

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1)	Volumes (2) DTH	Base Rate (3) $/DTH	Revenue (4) $	Average Rate (5) $/DTH
		(Ex 103, Sch 2)	(Ex 103, Sch 3)			
1	Rate Schedule RSS - Residential Sales Service					
2	RESIDENTIAL					
3	Customer Charge	3,574,045		18.73	66,941,863	
4	Commodity Charge:					
5	First 2.1 Dth		5,977,219.1	0.0000	0	
6	Over 2.1 Dth		17,132,807.1	2.6708	45,758,301	
7	Rider USP - Universal Service Plan		23,110,026.2	0.3595	8,308,054	
8	Subtotal				121,008,218	
9	STAS				(140,370)	
10	Base Rate Revenue				120,867,848	
11	Gas Cost		23,110,026.2	4.3212	99,863,045	
12	Unbundled Uncollectibles		23,110,026.2	0.0590	1,363,492	
13	Storage Interest		23,110,026.2	0.0000	0	
14	Total Rate Schedule RSS	3,574,045	23,110,026.2		222,094,385	9.6103
15	Rate Schedule RDGSS - Residential Distributed Generation Sales Service					
16	RESIDENTIAL					
17	Customer Charge	295		18.73	5,525	
18	Commodity Charge:					
19	First 2.1 Dth		548.0	0.0000	0	
20	Over 2.1 Dth		2,213.8	2.6708	5,913	
21	Rider USP - Universal Service Plan		2,761.8	0.3595	993	
22	Subtotal				12,431	
23	STAS				(14)	
24	Base Rate Revenue				12,417	
25	Gas Cost		2,761.8	4.3212	11,934	
26	Unbundled Uncollectibles		2,761.8	0.0590	163	
27	Storage Interest		2,761.8	0.0000	0	
28	Total Rate Schedule RDGSS	295	2,761.8		24,514	8.8761
29	Rate Schedule SGSS - Small General Sales Service (< 64,380 Therms Annually)					
30	COMMERCIAL					
31	Customer Charge:					
32	Less Than 6,438 Therms Annually	273,952		20.18	5,528,351	
33	6,438 - 64,380 Therms Annually	43,282		32.09	1,388,919	
34	Commodity Charge:					
35	All Gas Consumed		8,086,967.1	2.0658	16,706,057	
36	Subtotal		8,086,967.1		23,623,327	
37	STAS				(27,403)	
38	Base Rate Revenue				23,595,924	
39	Gas Cost		8,086,967.1	4.3212	34,945,402	
40	Unbundled Uncollectibles		8,086,967.1	0.0590	477,131	
41	Storage Interest		8,086,967.1	0.0000	0	
42	Total Commercial SGSS	317,234	8,086,967.1		59,018,457	7.2980

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1)	Volumes (2) DTH	Base Rate (3) $/DTH	Revenue (4) $	Average Rate (5) $/DTH
		(Ex 103, Sch 2)	*(Ex 103, Sch 3)*			
1	Rate Schedule SGSS - Small General Sales Service (< 64,380 Therms Annually)					
2	INDUSTRIAL					
3	Customer Charge:					
4	Less Than 6,438 Therms Annually	192		20.18	3,875	
5	6,438 - 64,380 Therms Annually	518		32.09	16,623	
6	Commodity Charge:					
7	All Gas Consumed		126,957.1	2.0658	262,268	
8	Subtotal		126,957.1		282,766	
9	STAS				(328)	
10	Base Rate Revenue				282,438	
11	Gas Cost		126,957.1	4.3212	548,607	
12	Unbundled Uncollectibles		126,957.1	0.0590	7,490	
13	Storage Interest		126,957.1	0.0000	0	
14	Total Industrial SGSS	710	126,957.1		838,535	6.6049
15	Total Rate Schedule SGSS	317,944	8,213,924.2		59,856,992	7.2873
16	Rate Schedule NSS - Negotiated Sales Service					
17	COMMERCIAL					
18	Customer Charge					
19	Less than 6,438 Therms Annually	0		20.18	0	
20	6,438 - 64,380 Therms Annually	0		32.09	0	
21	64,380 - 107,289 Therms Annually	0		125.12	0	
22	107,289 - 536,489 Therms Annually	0		469.34	0	
23	536,489 - 1,072,989 Therms Annually	12		1,149.00	13,788	
24	Commodity Charge:					
25	Less than 6,438 Therms Annually		0.0	2.0658	0	
26	6,438 - 64,380 Therms Annually		0.0	2.0658	0	
27	64,380 - 107,289 Therms Annually		0.0	1.1416	0	
28	107,289 - 536,489 Therms Annually		0.0	1.1416	0	
29	536,489 - 1,072,989 Therms Annually		61,000.0	0.0935	5,704	
30	Subtotal		61,000.0		19,492	
31	STAS				(23)	
32	Base Rate Revenue				19,469	
33	Gas Cost - Commodity			(workpaper)	195,281	
34	Gas Cost - Demand		6,600.0		56,384	
35	Total Rate Schedule NSS	12	61,000.0		271,094	4.4442
36	INDUSTRIAL					
37	Customer Charge					
38	Less than 6,438 Therms Annually	0		20.18	0	
39	64,380 - 107,989 Annually	0		125.12	0	
40	Commodity Charge:					
41	Less than 6,438 Therms Annually		0.0	2.0658	0	
42	64,380 - 107,989 Annually		0.0	1.1416	0	
43	Subtotal				0	
44	STAS				0	
45	Base Rate Revenue				0	
46	Gas Cost - Commodity		0.0	(workpaper)	0	
47	Total Rate Schedule NSS	0	0.0		0	0.0000

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1)	Volumes (2) DTH	Base Rate (3) $/DTH	Revenue (4) $	Average Rate (5) $/DTH
		(Ex 103, Sch 2)	(Ex 103, Sch 3)			
1	Rate Schedule LGSS - Large General Sales Service					
2	COMMERCIAL					
3	Customer Charge:					
4	Less Than 107,300 Therms Annually	517		125.12	64,687	
5	107,300 - 536,489 Therms Annually	319		469.34	149,719	
6	536,489 - 1,072,989 Therms Annually	12		1,149.00	13,788	
7	1,072,989 - 3,219,000 Therms Annually	0		2,050.00	0	
8	3,219,000 - 7,510,989 Therms Annually	0		4,096.00	0	
9	> 7,510,989 Therms Annually	0		7,322.00	0	
10	Commodity Charge:					
11	First 1,073.0 Dth		499,160.1	1.4241	710,840	
12	Next 4,292.0 Dth		314,356.6	1.3707	430,889	
13	Next 5,365.0 Dth		15,934.9	1.3390	21,337	
14	Over 10,730.0 Dth		0.0	1.1416	0	
15	Subtotal		829,441.6		1,391,260	
16	STAS				(1,614)	
17	Base Rate Revenue				1,389,646	
18	Gas Cost		829,441.6	4.3212	3,584,183	
19	Storage Interest		829,441.6	0.0000	0	
20	Total Commercial LGSS	848	829,441.6		4,973,829	5.9966
21	INDUSTRIAL					
22	Customer Charge:					
23	Less Than 107,300 Therms Annually	48		125.12	6,006	
24	107,300 - 536,489 Therms Annually	49		469.34	22,998	
25	536,489 - 1,072,989 Therms Annually	0		1,149.00	0	
26	1,072,989 - 3,219,000 Therms Annually	0		2,050.00	0	
27	3,219,000 - 7,510,989 Therms Annually	0		4,096.00	0	
28	> 7,510,989 Therms Annually	0		7,322.00	0	
29	Commodity Charge:					
30	First 1,073.0 Dth		74,881.3	1.4241	106,610	
31	Next 4,292.0 Dth		27,181.4	1.3707	37,258	
32	Next 5,365.0 Dth		0.0	1.3390	0	
33	Over 10,730.0 Dth		0.0	1.1416	0	
34	Subtotal		102,042.7		172,872	
35	STAS				(201)	
36	Base Rate Revenue				172,671	
37	Gas Cost		102,042.7	4.3212	440,947	
38	Storage Interest		102,042.7	0.0000	0	
39	Total Industrial LGSS	97	102,042.7		613,618	6.0133
40	Total Rate Schedule LGSS	945	931,484.3		5,587,447	5.9984

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1) *(Ex 103, Sch 2)*	Volumes (2) DTH *(Ex 103, Sch 3)*	Base Rate (3) $/DTH	Revenue (4) $	Average Rate (5) $/DTH
1	**Tariff Sales Summary by Customer Class**					
2	Base Rate Revenue				112,711,602	
3	STAS				(140,384)	
4	Rider USP				8,309,047	
5	Unbundled Uncollectibles				1,363,655	
6	Storage Interest				0	
7	Gas Cost				99,874,979	
8	Total Residential Sales	3,574,340	23,112,788.0		222,118,899	
9	Base Rate Revenue				25,034,079	
10	STAS				(29,040)	
11	Unbundled Uncollectibles				477,131	
12	Storage Interest				0	
13	Gas Cost				38,781,210	
14	Total Commercial Sales	318,094	8,977,408.7		64,263,380	
15	Base Rate Revenue				455,638	
16	STAS				(529)	
17	Unbundled Uncollectibles				7,490	
18	Storage Interest				0	
19	Gas Cost				989,554	
20	Total Industrial Sales	807	228,999.8		1,452,153	
21	Total Tariff Sales	3,893,241	32,319,196.5		287,834,432	

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1)	Volumes (2) DTH	Base Rate (3) $/DTH	Revenue (4) $	Average Rate (5) $/DTH
		(Ex 103, Sch 2)	*(Ex 103, Sch 3)*			
1	**Rate Schedule RDS - Residential Distribution Service (Choice)**					
2	RESIDENTIAL					
3	Customer Charge	813,396		18.73	15,234,907	
4	Commodity Charge:					
5	First 2.1 Dth		1,457,410.0	0.0000	0	
6	Over 2.1 Dth		5,632,309.1	2.6708	15,042,771	
7	Rider USP - Universal Service Plan		7,089,719.1	0.3595	2,548,754	
8	Subtotal				32,826,432	
9	STAS				(38,079)	
10	Base Rate Revenue				32,788,353	
11	Gas Cost		7,089,719.1	0.8731	6,190,034	
12	Storage Interest		7,089,719.1	0.0000	0	
13	Total Rate Schedule RDS	813,396	7,089,719.1		38,978,387	5.4979
14	**Residential Distribution Service (CAP)**					
15	RESIDENTIAL					
16	Customer Charge	224,703		18.73	4,208,687	
17	Commodity Charge:					
18	First 2.1 Dth		411,203.9	0.0000	0	
19	Over 2.1 Dth		2,171,325.6	2.6708	5,799,176	
20	Subtotal		2,582,529.5		10,007,863	
21	STAS				(11,609)	
22	Base Rate Revenue				9,996,254	
23	Gas Cost		2,582,529.5	0.8731	2,254,807	
24	Storage Interest		2,582,529.5	0.0000	0	
25	Total Rate Schedule RCC	224,703	2,582,529.5		12,251,061	4.7438
26	**Rate Schedule RDGDS - Residential Distributed Generation Distribution Service (Choice)**					
27	RESIDENTIAL					
28	Customer Charge	60		18.73	1,124	
29	Commodity Charge:					
30	First 2.1 Dth		112.3	0.0000	0	
31	Over 2.1 Dth		638.9	2.6708	1,706	
32	Rider USP - Universal Service Plan		751.2	0.3595	270	
33	Subtotal				3,100	
34	STAS				(4)	
35	Base Rate Revenue				3,096	
36	Gas Cost		751.2	0.8731	656	
37	Storage Interest		751.2	0.0000	0	
38	Total Rate Schedule PRDGDS	60	751.2		3,752	4.9947
39	**Rate Schedule SCD - Small Commercial Distribution (Choice)**					
40	COMMERCIAL					
41	Customer Charge					
42	Less Than 6,438 Therms Annually	91,873		20.18	1,853,997	
43	6,438 - 64,380 Therms Annually	4,286		32.09	137,538	
44	Commodity Charge:					
45	All Gas Consumed		1,486,997.4	2.0658	3,071,839	
46	Subtotal				5,063,374	
47	STAS				(5,874)	
48	Base Rate Revenue				5,057,500	
49	Gas Cost		1,486,997.4	0.8731	1,298,297	
50	Storage Interest		1,486,997.4	0.0000	0	
51	Total Rate Schedule SCD	96,159	1,486,997.4		6,355,797	4.2742

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1) (Ex 103, Sch 2)	Volumes (2) DTH (Ex 103, Sch 3)	Base Rate (3) $/DTH	Revenue (4) $	Average Rate (5) $/DTH
1	Rate Schedule SGDS - Small General Distribution Service					
2	COMMERCIAL					
3	Customer Charge:					
4	Less Than 6,438 Therms Annually	6,354		20.18	128,224	
5	6,438 - 64,380 Therms Annually	18,662		32.09	598,864	
6	Total	25,016				
7	Commodity Charge:					
8	Priority 1 - Aggregation		689,918.5	2.0658	1,425,234	
9	All Other Aggregation		2,845,240.3	2.0658	5,877,697	
10	Subtotal		3,535,158.8		8,030,019	
11	STAS				(9,315)	
12	Subtotal				8,020,704	
13	Flex	97	24,000.0	(workpaper)	30,889	
14	Priority 1 Gas Cost		689,918.5	1.1717	808,378	
15	Storage Interest		689,918.5	0.0000	0	
16	Total Commercial SGDS	25,113	3,559,158.8		8,859,971	2.4893
17	INDUSTRIAL					
18	Customer Charge:					
19	Less Than 6,438 Therms Annually	164		20.18	3,310	
20	6,438 - 64,380 Therms Annually	254		32.09	8,151	
21	Total	418				
22	Commodity Charge:					
23	Priority 1 - Aggregation		607.8	2.0658	1,256	
24	All Other Aggregation		80,961.8	2.0658	167,251	
25	Subtotal		81,569.6		179,968	
26	STAS				(209)	
27	Subtotal				179,759	
28	Flex	12	1,800.0	(workpaper)	1,257	
29	Priority 1 Gas Cost		607.8	1.1717	712	
30	Storage Interest		607.8	0.0000	0	
31	Total Industrial SGDS	430	83,369.6		181,728	2.1798
32	Total Rate Schedule SGDS	25,543	3,642,528.4		9,041,699	2.4823

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1)	Volumes (2) DTH	Base Rate (3) $/DTH	Revenue (4) $	Average Rate (5) $/DTH
		(Ex 103, Sch 2)	*(Ex 103, Sch 3)*			
1	Rate Schedule SDS - Small Distribution Service					
2	COMMERCIAL					
3	Customer Charge:					
4	Less Than 107,300 Therms Annually	1,991		125.12	249,114	
5	107,300 - 536,490 Therms Annually	1,685		469.34	790,838	
6	Total	3,676				
7	Commodity Charge:					
8	Deliveries		3,986,927.1	1.1416	4,551,476	
9	Subtotal				5,591,428	
10	STAS				(6,486)	
11	Flexed Deliveries	108	198,700.0	(workpaper)	201,904	
12	Total Commercial SDS	3,784	4,185,627.1		5,786,846	1.3826
13	INDUSTRIAL					
14	Customer Charge:					
15	Less Than 107,300 Therms Annually	248		125.12	31,030	
16	107,300 - 536,490 Therms Annually	996		469.34	467,463	
17	Total	1,244				
18	Commodity Charge:					
19	Deliveries		2,837,531.4	1.1416	3,239,326	
20	Subtotal				3,737,819	
21	STAS				(4,336)	
22	Flexed Deliveries	0	0.0	(workpaper)	0	
23	Total Industrial SDS	1,244	2,837,531.4		3,733,483	1.3158
24	Total Rate Schedule SDS	5,028	7,023,158.5		9,520,329	1.3556
25	Rate Schedule LDS - Large Distribution Service					
26	COMMERCIAL					
27	Customer Charge:					
28	536,500 - 1,073,000 Therms Annually	134		1,227.00	164,418	
29	1,073,000 - 3,219,000 Therms Annually	108		2,190.00	236,520	
30	3,219,000 - 7,511,000 Therms Annually	12		4,526.00	54,312	
31	> 7,511,000 Therms Annually	0		7,322.00	0	
32	Total	254				
33	Commodity Charge:					
34	536,500 - 1,073,000 Therms Annually		730,543.2	0.9270	677,214	
35	1,073,000 - 3,219,000 Therms Annually		1,178,600.0	0.8114	956,316	
36	3,219,000 -7,511,000 Therms Annually		690,000.0	0.6716	463,404	
37	>7,511,000 Therms Annually		0.0	0.6716	0	
38	Total Commercial Deliveries		2,599,143.2		2,096,934	
39	Subtotal				2,552,184	
40	STAS				(2,961)	
41	Flexed Deliveries	12	226,000.0	(workpaper)	123,588	
42	Total Commercial LDS	266	2,825,143.2		2,672,811	0.9461

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1)	Volumes (2) DTH	Base Rate (3) $/DTH	Revenue (4) $	Average Rate (5) $/DTH
		(Ex 103, Sch 2)	*(Ex 103, Sch 3)*			
1	Rate Schedule LDS - Large Distribution Service					
2	INDUSTRIAL					
3	Customer Charge:					
4	536,500 - 1,072,989 Therms Annually	305		1,227.00	374,235	
5	1,073,000 - 3,219,000 Therms Annually	206		2,190.00	451,140	
6	3,219,000 - 7,511,000 Therms Annually	72		4,526.00	325,872	
7	> 7,511,000 Therms Annually	0		7,322.00	0	
8	Total	583				
9	Commodity Charge:					
10	536,500 - 1,072,989 Therms Annually		1,892,598.8	0.9270	1,754,439	
11	1,073,000 - 3,219,000 Therms Annually		2,938,200.0	0.8114	2,384,055	
12	3,219,000 -7,511,000 Therms Annually		2,457,000.0	0.6716	1,650,121	
	>7,511,000 Therms Annually		0.0	0.6716	0	
13	Total Industrial Deliveries		7,287,798.8		5,788,615	
14	Subtotal				6,939,862	
15	STAS				(6,050)	
16	Flexed Deliveries	252	7,675,400.0	(workpaper)	3,246,226	
17	Total Industrial LDS	835	14,963,198.8		10,178,037	0.6802
18	Total Rate Schedule LDS	1,101	17,788,342.0		12,850,848	0.7224
19	Rate Schedule MLDS - Main Line Distribution Service - Class I					
20	COMMERCIAL					
21	Customer Charge:					
22	268,250 - 536,500 Therms Annually	0		469.34	0	
23	536,500 - 1,073,000 Therms Annually	12		1,149.00	13,788	
24	1,073,000 - 3,219,000 Therms Annually	0		2,050.00	0	
25	3,219,000 - 7,511,000 Therms Annually	0		4,096.00	0	
26	> 7,511,000 Therms Annually	0		7,322.00	0	
27	Total	12				
28	Commodity Charge:					
29	All Gas Consumed		102,100.0	0.0935	9,546	
30	Subtotal				23,334	
31	STAS				(27)	
32	Flexed	0	0.0	(workpaper)	0	
33	Total Commercial MLDS - Class I	12	102,100.0		23,307	0.2283

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1)	Volumes (2) DTH	Base Rate (3) $/DTH	Revenue (4) $	Average Rate (5) $/DTH
		(Ex 103, Sch 2)	*(Ex 103, Sch 3)*			
1	**Rate Schedule MLDS - Main Line Distribution Service - Class I**					
2	**INDUSTRIAL**					
3	Customer Charge:					
4	268,250 - 536,500 Therms Annually	12		469.34	5,632	
5	536,500 - 1,073,000 Therms Annually	0		1,149.00	0	
6	1,073,000 - 3,219,000 Therms Annually	12		2,050.00	24,600	
7	3,219,000 - 7,511,000 Therms Annually	0		4,096.00	0	
8	> 7,511,000 Therms Annually	0		7,322.00	0	
9	Total	24				
10	Commodity Charge:					
11	All Gas Consumed		112,300.0	0.0935	10,500	
12	Subtotal				40,732	
13	STAS				(47)	
14	Flexed	12	2,964,000.0	(workpaper)	364,998	
15	Total Industrial MLDS - Class I	36	3,076,300.0		405,683	0.1319
16	Total Rate Schedule MLDS - Class I	48	3,176,400.0		428,990	0.1350
17	**Rate Schedule MLDS - Main Line Distribution Service - Class II**					
18	**INDUSTRIAL**					
19	Customer Charge:					
20	268,250 - 536,500 Therms Annually	0		469.34	0	
21	536,500 - 1,073,000 Therms Annually	0		1,149.00	0	
22	1,073,000 - 3,219,000 Therms Annually	12		2,050.00	24,600	
23	3,219,000 - 7,511,000 Therms Annually	0		4,096.00	0	
24	> 7,511,000 Therms Annually	0		7,322.00	0	
25	Total	12				
26	Commodity Charge:					
27	Less Than 1,073,000 Therms Annually		0.0	0.5264	0	
28	1,073,000 - 3,219,000 Therms Annually		296,000.0	0.4471	132,342	
29	3,219,000 - 7,511,000 Therms Annually		0.0	0.3866	0	
30	> 7,511,000 Therms Annually		0.0	0.3349	0	
31	Subtotal		296,000.0		156,942	
32	STAS				(182)	
33	Flexed	48	1,684,000.0	(workpaper)	644,200	
34	Total Industrial MLDS - Class II	60	1,980,000.0		800,960	0.4045

Columbia Gas of Pennsylvania, Inc.
Revenue @ Current Rates Based on Forecast Adjusted Bills and Volumes
For the 12 Months Ended June 30, 2014

Line No.	Description	Bills (1)	Volumes (2) DTH	Base Rate (3) $/DTH	Revenue (4) $
1	**Transportation Summary by Customer Class**				
2	Residential				
3	Base Rate Revenue				40,288,371
4	STAS				(49,692)
5	Rider USP				2,549,024
6	Storage Interest				0
7	Gas Cost				8,445,497
8	Total Residential Transportation	1,038,159	9,673,000		51,233,200
9	Commercial				
10	Base Rate Revenue				21,616,720
11	STAS				(24,663)
12	Storage Interest				0
13	Gas Cost				2,106,675
14	Total Commercial Transportation	125,334	12,159,026.5		23,698,732
15	Industrial				
16	Base Rate Revenue				15,312,003
17	STAS				(12,824)
18	Storage Interest				0
19	Gas Cost				712
20	Total Industrial Transportation	2,605	22,940,399.8		15,299,891
21	Total Transportation	1,166,098	44,772,426.1		90,231,823
22	**Total Company Throughput**	5,059,339	77,091,622.6		378,066,255
23	**Other Operating Revenue**				
24	487 - Forfeited Discounts				1,137,995
25	488 - Miscellaneous Service Revenues				146,687
26	493 - Rent from Gas Property				173,011
27	495 - Prior Yr. Rate Refund - Net.				0
28	495 - Off System Sales				0
29	495 - Other Gas Revenues - Other				144,725
30	496 - Provision For Rate Refunds				0
31	**Total Other Operating Revenue**				1,602,418
32	**Total Company Revenue**				379,668,673

Columbia Gas of Pennsylvania, Inc.
Number of Bills
For the 12 Months Ended June 30, 2014

Line No.	Description	Per Forecast (1)	Bills from Industrial & Lg Com Customers (2) (Ex 103, Sch 4)	Incremental Bills New Const (3) (Ex 103, Sch 4)	Incremental Bills Attrition (4) (Ex 103, Sch 4)	Rate Schedule Change (6)	Finalod Bills (5)	Per Forecast Adjusted (6=1 to 5)
1	Rate Schedule RSS - Residential Sales Service							
2	RESIDENTIAL							
3	Total Rate Schedule RSS	3,513,695	0	16,737	(8,988)	0	52,601	3,574,045
4	Rate Schedule RDGSS - Residential Distributed Generation Sales Service							
5	RESIDENTIAL							
6	Total Rate Schedule RDGSS	294	0	0	0	0	1	295
7	Rate Schedule SGSS - Small General Sales Service (< 64,380 Therms Annually)							
8	COMMERCIAL							
9	Less Than 6,438 Therms Annually	272,437	0	2,233	(3,246)	24	2,504	273,952
10	6,438 - 64,380 Therms Annually	43,197	0	0	0	(24)	109	43,282
11	Total Commercial Bills Under SGSS	315,634	0	2,233	(3,246)	0	2,613	317,234
12	INDUSTRIAL							
13	Less Than 6,438 Therms Annually	192	0	0	0	0	0	192
14	6,438 - 64,380 Therms Annually	516	0	0	0	0	2	518
15	Total Industrial Bills Under SGSS	708	0	0	0		2	710
16	Total Rate Schedule SGSS	316,342	0	2,233	(3,246)	0	2,615	317,944
17	Rate Schedule NSS - Negotiated Sales Service							
18	COMMERCIAL							
19	Less than 6,438 Therms Annually	0	0	0	0	0	0	0
20	6,438 - 64,380 Therms Annually	0	0	0	0	0	0	0
21	64,380 - 107,289 Therms Annually	0	0	0	0	0	0	0
22	107,289 - 536,489 Therms Annually	0	0	0	0	0	0	0
23	536,489 - 1,072,989 Therms Annually	12	0	0	0	0	0	12
24	INDUSTRIAL							
25	Less than 6,438 Therms Annually	0	0	0	0	0	0	0
26	64,380 - 107,989 Annually	0	0	0	0	0	0	0

Columbia Gas of Pennsylvania, Inc.
Number of Bills
For the 12 Months Ended June 30, 2014

Line No.	Description	Per Forecast (1)	Bills from Industrial & Lg Com Customers (2) *(Ex 103, Sch 4)*	Incremental Bills New Const (3) *(Ex 103, Sch 4)*	Incremental Bills Attrition (4) *(Ex 103, Sch 4)*	Rate Schedule Change (6)	Finaled Bills (5)	Per Forecast Adjusted (6=1 to 5)
1	Rate Schedule LGSS - Large General Sales Service							
2	COMMERCIAL							
3	Less Than 107,300 Therms Annually	504	0	0	0	12	1	517
4	107,300 - 536,489 Therms Annually	330	0	0	0	(12)	1	319
5	536,489 - 1,072,989 Therms Annually	12	0	0	0	0	0	12
6	1,072,989 - 3,219,000 Therms Annually	0	0	0	0	0	0	0
7	3,219,000 - 7,510,989 Therms Annually	0	0	0	0	0	0	0
8	> 7,510,989 Therms Annually	0	0	0	0	0	0	0
9	Total Commercial Bills Under LGSS	846	0	0	0	0	2	848
10	INDUSTRIAL							
11	Less Than 107,300 Therms Annually	48	0	0	0	0	0	48
12	107,300 - 536,489 Therms Annually	48	0	0	0	0	1	49
13	536,489 - 1,072,989 Therms Annually	0	0	0	0	0	0	0
14	1,072,989 - 3,219,000 Therms Annually	0	0	0	0	0	0	0
15	3,219,000 - 7,510,989 Therms Annually	0	0	0	0	0	0	0
16	> 7,510,989 Therms Annually	0	0	0	0	0	0	0
17	Total Industrial Bills Under LGSS	96	0	0	0	0	1	97
18	Total Rate Schedule LGSS	942	0	0	0	0	3	945
19	**Tariff Sales Summary by Customer Class**							
20	Total Residential Sales	3,513,989	0	16,737	(8,988)	0	52,602	3,574,340
21	Total Commercial Sales	316,492	0	2,233	(3,246)	0	2,615	318,094
22	Total Industrial Sales	804	0	0	0	0	3	807
23	Total Tariff Sales	3,831,285	0	18,970	(12,234)	0	55,220	3,893,241

Columbia Gas of Pennsylvania, Inc.
Number of Bills
For the 12 Months Ended June 30, 2014

Line No.	Description	Per Forecast (1)	Bills from Industrial & Lg Com Customers (2) (Ex 103, Sch 4)	Incremental Bills New Const (3) (Ex 103, Sch 4)	Incremental Bills Attrition (4) (Ex 103, Sch 4)	Rate Schedule Change (6)	Finaled Bills (5)	Per Forecast Adjusted (6=1 to 5)
1	Rate Schedule RDS - Residential Distribution Service (Choice)							
2	RESIDENTIAL							
3	Total Rate Schedule RDS	807,296	0	0	0	0	6,100	813,396
4	Residential Distribution Service (CAP)							
5	RESIDENTIAL							
6	Total Rate Schedule RCC	220,441	0	0	0	0	4,262	224,703
7	Rate Schedule RDGDS - Residential Distributed Generation Distribution Service (Choice)							
8	RESIDENTIAL							
9	Total Rate Schedule RDGDS	60	0	0	0	0	0	60
10	Rate Schedule SCD - Small Commercial Distribution (Choice)							
11	COMMERCIAL							
12	Less Than 6,438 Therms Annually	91,413	0	0	0	0	460	91,873
13	6,438 - 64,380 Therms Annually	4,284	0	0	0	0	2	4,286
14	Total Rate Schedule SCD	95,697	0	0	0	0	462	96,159
15	Rate Schedule SGDS - Small General Distribution Service							
16	COMMERCIAL							
17	Less Than 6,438 Therms Annually - Aggregati	6,336	(24)	0	0	0	42	6,354
18	6,438 - 64,380 Mcf Annually - Aggregation	18,612	0	0	0	0	50	18,662
19	Flex	96	0	0	0	0	1	97
20	Total Commercial Bills Under SGDS	25,044	(24)	0	0	0	93	25,113
21	INDUSTRIAL							
22	Less Than 6,438 Therms Annually - Aggregati	156	0	0	0	0	8	164
23	6,438 - 64,380 Mcf Annually - Aggregation	252	0	0	0	0	2	254
24	Flex	12	0	0	0	0	0	12
25	Total Industrial Bills Under SGDS	420	0	0	0	0	10	430
26	Total Rate Schedule SGDS	25,464	(24)	0	0	0	103	25,543

Columbia Gas of Pennsylvania, Inc.
Number of Bills
For the 12 Months Ended June 30, 2014

Line No.	Description	Per Forecast (1)	Bills from Industrial & Lg Com Customers (2) (Ex 103, Sch 4)	Incremental Bills New Const (3) (Ex 103, Sch 4)	Incremental Bills Attrition (4) (Ex 103, Sch 4)	Rate Schedule Change (6)	Finaled Bills (5)	Per Forecast Adjusted (6=1 to 5)
1	Rate Schedule SDS - Small Distribution Service							
2	COMMERCIAL							
3	64,380 - 107,300 Therms Annually	1,932	0	0	0	36	23	1,991
4	107,300 - 536,490 Therms Annually	1,728	(12)	0	0	(36)	5	1,685
5	Flex	96	12	0	0	0	0	108
6	Total Commercial Bills Under SDS	3,756	0	0	0	0	28	3,784
7	INDUSTRIAL							
8	64,380 - 107,300 Therms Annually	240	0	0	0	0	8	248
9	107,300 - 536,490 Therms Annually	996	0	0	0	0	0	996
10	Flex	0	0	0	0	0	0	0
11	Total Industrial Bills Under SDS	1,236	0	0	0	0	8	1,244
12	Total Rate Schedule SDS	4,992	0	0	0	0	36	5,028
13	Rate Schedule LDS - Large Distribution Service							
14	COMMERCIAL							
15	536,500 - 1,072,989 Therms Annually	132	0	0	0	0	2	134
16	1,073,000 - 3,219,000 Therms Annually	108	0	0	0	0	0	108
17	3,219,000 - 7,511,000 Therms Annually	12	0	0	0	0	0	12
18	> 7,511,000 Therms Annually	0	0	0	0	0	0	0
19	Flex	12	0	0	0	0	0	12
20	Total Commercial Bills Under LDS	264	0	0	0	0	2	266
21	INDUSTRIAL							
22	536,500 - 1,072,989 Therms Annually	300	0	0	0	0	5	305
23	1,073,000 - 3,219,000 Therms Annually	204	0	0	0	0	2	206
24	3,219,000 - 7,511,000 Therms Annually	72	0	0	0	0	0	72
25	> 7,511,000 Therms Annually	0	0	0	0	0	0	0
26	Flex	252	0	0	0	0	0	252
27	Total Industrial Bills Under LDS	828	0	0	0	0	7	835
28	Total Rate Schedule LDS	1,092	0	0	0	0	9	1,101

Columbia Gas of Pennsylvania, Inc.
Number of Bills
For the 12 Months Ended June 30, 2014

Line No.	Description	Per Forecast (1)	Bills from Industrial & Lg Com Customers (2) *(Ex 103, Sch 4)*	Incremental Bills		Rate Schedule Change (6)	Finaled Bills (5)	Per Forecast Adjusted (6=1 to 5)
				New Const (3) *(Ex 103, Sch 4)*	Attrition (4) *(Ex 103, Sch 4)*			
1	Rate Schedule MLDS - Main Line Distribution Service - Class I							
2	COMMERCIAL							
3	268,250 - 536,500 Therms Annually	0	0	0	0	0	0	0
4	536,500 - 1,073,000 Therms Annually	12	0	0	0	0	0	12
5	1,073,000 - 3,219,000 Therms Annually	0	0	0	0	0	0	0
6	3,219,000 - 7,511,000 Therms Annually	0	0	0	0	0	0	0
7	> 7,511,000 Therms Annually	0	0	0	0	0	0	0
8	Commercial Bills Under MLDS - Class I	12	0	0	0	0	0	12
9	Flex	0	0	0	0	0	0	0
10	Total Commercial Bills Under MLDS	12	0	0	0	0	0	12
11	INDUSTRIAL							
12	268,250 - 536,500 Therms Annually	12	0	0	0	0	0	12
13	536,500 - 1,073,000 Therms Annually	0	0	0	0	0	0	0
14	1,073,000 - 3,219,000 Therms Annually	12	0	0	0	0	0	12
15	3,219,000 - 7,511,000 Therms Annually	0	0	0	0	0	0	0
16	> 7,511,000 Therms Annually	0	0	0	0	0	0	0
17	Industrial Bills Under MLDS - Class I	24	0	0	0	0	0	24
18	Flex	12	0	0	0	0	0	12
19	Total Industrial Bills Under MLDS	36	0	0	0	0	0	36
20	Total Rate Schedule MLDS - Class I	48	0	0	0	0	0	48
21	Rate Schedule MLDS - Main Line Distribution Service - Class II							
22	INDUSTRIAL							
23	268,250 - 536,500 Therms Annually	0	0	0	0	0	0	0
24	536,500 - 1,073,000 Therms Annually	0	0	0	0	0	0	0
25	1,073,000 - 3,219,000 Therms Annually	12	0	0	0	0	0	12
26	3,219,000 - 7,511,000 Therms Annually	0	0	0	0	0	0	0
27	> 7,511,000 Therms Annually	0	0	0	0	0	0	0
28	Industrial Bills Under MLDS - Class II	12	0	0	0	0	0	12
29	Flex	48	0	0	0	0	0	48
30	Total Industrial Bills Under MLDS	60	0	0	0	0	0	60
31	Total Rate Schedule MLDS - Class II	60	0	0	0	0	0	60

Columbia Gas of Pennsylvania, Inc.
Number of Bills
For the 12 Months Ended June 30, 2014

Line No.	Description	Per Forecast (1)	Bills from Industrial & Lg Com Customers (2) (Ex 103, Sch 4)	Incremental Bills New Const (3) (Ex 103, Sch 4)	Incremental Bills Attrition (4) (Ex 103, Sch 4)	Rate Schedule Change (6)	Finaled Bills (5)	Per Forecast Adjusted (6=1 to 5)
1	**Transportation Summary by Customer Class**							
2	Total Residential Transportation	1,027,797	0	0	0	0	10,362	1,038,159
3	Total Commercial Transportation	124,773	(24)	0	0	0	585	125,334
4	Total Industrial Transportation	2,580	0	0	0	0	25	2,605
5	Total Transportation	1,155,150	(24)	0	0	0	10,972	1,166,098
6	Total Company Throughput	4,986,435	(24)	18,970	(12,234)	0	66,192	5,059,339

COLUMBIA STATEMENT NO. 105-R

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission ,	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

JOHN J. SPANOS

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name.

A. John J. Spanos

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I have. My direct testimony was Statement No. 5.

Q. Please state the purpose of your rebuttal testimony.

A. The purpose of this testimony is to rebut the depreciation expense adjustment of the Company fully forecasted rate year set forth by Office of Consumer Advocate witness, Thomas S. Catlin.

Q. Mr. Catlin proposes to decrease the Company's Fully Forecasted Rate Year claim by $2,098,196. How did he develop this adjustment?

A. According to his Schedule TSC-16, Mr. Catlin simply utilized the 13-month averages. However, his Schedule TSC-16 inconsistently calculates amounts from various time periods.

Q. Do you agree with this adjustment?

A. No. Mr. Catlin utilized multiple sources to create his amounts in Schedule TSC-16, which are based on different time periods. Some are calculated amounts or percentages as of June 30, 2014 and others are 13-month averages. This mixing and matching of time periods produces an adjustment to depreciation expense which is unjustified.

Q. Can you elaborate on your concerns related to depreciation expense?

A. Yes. In Schedule TSC-16, Mr. Catlin establishes a 13-month average balance of Plant in Service ($1,401,796,427) and 13-month average of Amortization and Non-Depreciable Plant ($12,749,406) for a total 13-month average Balance of

Depreciable Plant in Service of $1,389,047,021. His next calculation is to multiply the 13-month average balance of Depreciable Plant in Service by the Composite Depreciation Rate of 2.3801. However, the 2.3801 composite depreciation rate is based on an original cost and book reserve developed at June 30, 2014 not the 13-month average. Therefore, the total Rate Year Depreciation and Amortization per OCA of $34,998,809 is not a reasonable amount to be compared to the Company's June 30, 2014 claim.

Q. Is the calculation of depreciation rates and expense for future test years a simple average as Mr. Catlin has proposed?

A. No, it is not. First, the book reserve is brought forward based on many calculations to annualize the depreciation accruals, retirements, amortization of net salvage, cost of removal, gross salvage, acquisitions and adjustments. The annualized depreciation accruals are determined by calculating the average plant balance of the test year by the depreciation rates for each individual account. The amortization of net salvage is determined based on the incurred cost of removal and gross salvage for the 5 years prior. The projected retirements, cost of removal and gross salvage are determined on a yearly basis in order to properly establish an end of test year book reserve. This is critical in order to properly annualize the book reserve in a consistent manner to the plant balance. This removes the over or under recovery concerns for new vintages within the year. Once the future test year (May 31, 2013) is determined the same process must occur for the fully forecasted rate year (June 30, 2014). Consequently, each account's depreciation rate and expense needs to be calculated on the vintage

plant balance and book reserve as of same date.

Q. Is the methodology you describe consistent with the process set forth in the Depreciation Studies?

A. Yes.

Q. Has this process been consistently approved before this Commission?

A. Yes. The calculations and determinations of all depreciation parameters in the Depreciation Studies are consistent with past practices for Columbia Gas of Pennsylvania and all other Pennsylvania utilities.

Q. Was there any other adjustment made by Mr. Catlin related to depreciation?

A. Yes. A related adjustment to the plant in service and the book reserve was the inclusion of Construction Work in Progress (CWIP). The CWIP that was included throughout the Depreciation Study calculations was $16,635,708. Therefore, the Depreciation Study calculations have been updated to match the Company's claim.

Q. Can you describe the revised depreciation tables and results?

A. Yes. Tables 1 (Exhibit JJS-1R) and 2 (Exhibit JJS-2R) set forth the calculation of the depreciation accruals for the period May 31, 2012 to May 31, 2013 and for the period May 31, 2013 to June 30, 2014, respectively. The updated depreciation accruals were included in the bring forward of the book reserve for May 31, 2013 and June 30, 2014. The revised bring forward schedules are set forth as Table 3 (Exhibit JJS-3R) for the period ended May 31, 2013 and Table 4 (Exhibit JJS-4R) for the period ended June 30, 2014. Consequently, as a result of the removal of CWIP from the depreciation claim, Table 5 (Exhibit JJS-5R) sets forth the

appropriate plant in service and associated depreciation expense for the fully forecasted rate year. The amount totals $36,535,282 and is a reduction of $561,723 from the original claim.

Q. Can you further detail the change in the book reserve from what was filed in the case and how Mr. Catlin presented the amounts?

A. Yes. There are two separate components that represent a change from the filed fully forecasted rate year Depreciation Study and Mr. Catlin's exhibits. First, the accumulated depreciation for Account 303 as of June 30, 2014 was presented incorrectly in summary rate base exhibits. The correct amount is $3,634,442 or $1,037,422 less than the amount originally reflected as accumulated depreciation at June 30, 2014. Second, as shown in the tables attached, and when utilizing the appropriate methods of developing the forecasted book reserve, the book reserve is reduced by an additional $1,010,772. This reduction in the reserve reflects the removal of the CWIP from the depreciation study calculations through the end of the fully forecasted rate year (June 30, 2014). Therefore, the simple averaging Mr. Catlin utilizes can produce very different results if proper considerations of the plant and reserve balances are not considered.

Q. Do your revised tables reflect the consistently approved methodology for future test year claims by the PaPUC?

A. Yes, they do.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.

SPANOS REBUTTAL_TABLE 1. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED MAY 31, 2013

	Depreciable Group	Original Cost at May 31, 2012	Original Cost at May 31, 2013	Composite Accrual Rate	Annual Accrual Amount
	(1)	(2)	(3)	(4)	(5)
DEPRECIABLE PLANT					
UNDERGROUND STORAGE PLANT					
350.2	Rights-of-Way	1,932	1,932	-	0
351	Compressor Station Structures	1,476,260	1,476,260	2.83	41,778
	Wells				
352.01	Construction	799,134	799,134	-	0
352.02	Equipment	168,680	168,680	-	0
	Total Account 352	967,813	967,813		0
352.1	Storage Leaseholds and Rights	206,941	206,941	0.06	124
353	Lines	405,288	405,288	-	0
354	Compressor Station Equipment	584,073	1,779,673	-	0
355	Measuring and Regulating Equipment	123,010	123,010	-	0
	Total Underground Storage Plant	3,765,317	4,960,917	1.15	41,902
DISTRIBUTION PLANT					
	Land and Land Rights				
374.4	Land Rights	1,858,095	1,929,895	1.67	31,630
374.5	Rights-of-Way	3,233,039	3,233,039	1.36	43,969
	Total Account 374	5,091,134	5,162,934	1.47	75,599
	Structures and Improvements				
375.34	Measuring and Regulating	2,716,157	3,145,057	2.20	64,473
375.6	Industrial Meas and Reg	87,692	87,692	1.44	1,263
375.7	Other Distribution System				
	Distribution System Structures	2,490,167	2,490,167	3.82	95,124
	Other Buildings	936,081	1,425,281	3.45	40,733
	Total Account 375.70	3,426,247	3,915,447	3.74	135,858
375.8	Communication Structures	16,515	16,515	2.15	355
	Total Account 375	6,246,612	7,164,712	3.11	201,949
376	Mains				
	Cast Iron	862,665	480,780	1.98	13,300
	Bare Steel	75,220,880	70,256,375	1.70	1,236,557
	Other	623,853,314	725,995,021	1.94	13,093,529
	Total Account 376	699,936,858	796,732,175	1.92	14,343,386
378	Meas and Reg Equipment - General	16,838,657	18,237,157	2.89	506,846
379.1	Meas and Reg Equipment - City Gate	153,794	153,794	3.62	5,567
380	Services				
	Bare Steel	1,043,119	897,569	0.61	5,919
	Other	293,921,193	329,956,743	2.60	8,110,413
	Total Account 380	294,964,312	330,854,312	2.60	8,116,332
381	Meters	31,834,475	32,849,975	2.48	802,087
381.1	Meters -AMR	18,827,703	20,208,503	7.91	1,543,882
382	Meter Installations	31,161,616	33,115,016	1.96	629,911
383	House Regulators	8,861,163	9,737,863	2.53	235,278
384	House Regulator Installations	3,864,772	3,864,772	1.96	75,750
385	Industrial Meas and Reg Equipment - Other than Meters	6,060,240	6,369,040	3.94	244,857

COLUMBIA GAS OF PENNSYLVANIA, INC.

SPANOS REBUTTAL_TABLE 1. CALCULATION OF DEPRECIATION ACCRUALS FOR THE TWELVE MONTHS ENDED MAY 31, 2013

	Depreciable Group	Original Cost at May 31, 2012	Original Cost at May 31, 2013	Composite Accrual Rate	Annual Accrual Amount
	(1)	(2)	(3)	(4)	(5)
	Other Equipment				
387	General	138,546	138,546	9.04	12,525
387.4	Customer Information Services	1,054,442	1,054,442	4.58	48,293
	Total Account 387	1,192,988	1,192,988	5.04	60,818
	Total Distribution Plant	1,125,034,325	1,265,643,242	2.26	26,842,261
GENERAL PLANT					
390.1	Structures and Improvements - Communications	49,821	49,821	0.49	244
	Office Furniture and Equipment				
391.1	Furniture	2,932,568	2,750,361	3.07	87,233
391.11	Equipment	49,805	53,582	3.17	1,639
391.12	Information Systems	2,373,106	2,603,567	15.08	375,241
	Total Account 391	5,355,479	5,407,509	8.39	464,113
392	Transportation Equipment - Trailers	221,546	195,040	8.05	16,768
393	Stores Equipment	17,116	17,116	2.41	413
	Tools, Shop and Garage Equipment				
394	Equipment	10,167,409	10,549,745	3.60	372,909
394.12	CNG Facilities	1,953,498	1,953,498	0.07	1,367
	Total Account 394	12,120,907	12,503,243	3.03	374,276
395	Laboratory Equipment	80,027	78,986	5.81	4,619
396	Power Operated Equipment	1,772,200	1,772,200	2.83	50,153
	Communication Equipment				
397.1	Telephone	1,117,051	976,525	8.74	91,489
397.24	Radio	2,351,931	2,392,491	7.59	180,051
397.5	Telemetering	880,440	895,260	5.24	46,523
	Total Account 397	4,349,422	4,264,276	7.41	318,063
398	Miscellaneous Equipment	371,838	564,621	6.41	30,014
	Total General Plant	24,338,357	24,852,812	5.08	1,258,663
	Subtotal Depreciable Plant	1,153,137,998	1,295,456,971		28,142,826
AMORTIZABLE PLANT					
303	Intangible plant	9,159,560	9,317,538	*	1,197,758
305	Structures and Improvements				
362	Gas Holders				
362.1	Environmental Remediation				
374.2	Land, Other Distribution Systems	480,964	480,964		
375.71	Structures and Improvements - leased	1,031,960	1,031,960	*	254,775
389.2	Land and Land Rights - Land Rights				
	Subtotal Amortizable Plant	10,672,484	10,830,461		1,452,533
NONDEPRECIABLE PLANT		172,413	172,413		
	Total Gas Plant	1,163,982,895	1,306,459,845		29,595,359

* Prorated accruals based on individual asset amortization

COLUMBIA GAS OF PENNSYLVANIA, INC.

SPANOS REBUTTAL_TABLE 2. CALCULATION OF DEPRECIATION ACCRUALS FOR THE THIRTEEN MONTHS ENDED JUNE 30, 2014

	Depreciable Group	Original Cost at May 31, 2013	Original Cost at June 30, 2014	Composite Accrual Rate	13 Month Accrual Amount
	(1)	(2)	(3)	(4)	(5)
DEPRECIABLE PLANT					
UNDERGROUND STORAGE PLANT					
350.2	Rights-of-Way	1,932	1,932	-	0
351	Compressor Station Structures	1,476,260	1,476,260	2.83	45,120
	Wells				
352.01	Construction	799,134	799,134	-	0
352.02	Equipment	168,680	168,680	-	0
	Total Account 352	967,813	967,813		0
352.1	Storage Leaseholds and Rights	206,941	206,941	0.06	134
353	Lines	405,288	405,288	-	0
354	Compressor Station Equipment	1,779,673	2,796,973	3.68 **	90,947
355	Measuring and Regulating Equipment	123,010	123,010	-	0
	Total Underground Storage Plant	4,960,917	5,978,217	1.15	136,201
DISTRIBUTION PLANT					
	Land and Land Rights				
374.4	Land Rights	1,929,895	2,024,995	1.67	35,665
374.5	Rights-of-Way	3,233,039	3,233,039	1.36	47,487
	Total Account 374	5,162,934	5,258,034	1.47	83,152
	Structures and Improvements				
375.34	Measuring and Regulating	3,145,057	3,522,257	2.20	79,208
375.6	Industrial Meas and Reg	87,692	87,692	1.44	1,364
375.7	Other Distribution System				
	Distribution System Structures	2,490,167	2,490,167	3.82	102,734
	Other Buildings	1,425,281	1,660,081	3.45	57,480
	Total Account 375.70	3,915,447	4,150,247	3.74	160,214
375.8	Communication Structures	16,515	16,515	2.15	383
	Total Account 375	7,164,712	7,776,712	3.11	241,169
376	Mains				
	Cast Iron	480,780	16,180	1.98	5,313
	Bare Steel	70,256,375	64,216,575	1.70	1,234,462
	Other	725,995,021	847,053,421	1.94	16,479,255
	Total Account 376	796,732,175	911,286,175	1.92	17,719,030
378	Meas and Reg Equipment - General	18,237,157	19,462,757	2.89	588,345
379.1	Meas and Reg Equipment - City Gate	153,794	153,794	3.62	6,013
380	Services				
	Bare Steel	897,569	722,594	0.61	5,337
	Other	329,956,743	373,279,218	2.60	9,873,433
	Total Account 380	330,854,312	374,001,812	2.60	9,878,770
381	Meters	32,849,975	34,301,875	2.48	899,298
381.1	Meters -AMR	20,208,503	20,543,303	7.91	1,740,673
382	Meter Installations	33,115,016	35,468,816	1.96	725,891
383	House Regulators	9,737,863	10,741,263	2.53	279,786
384	House Regulator Installations	3,864,772	3,864,772	1.96	81,809
385	Industrial Meas and Reg Equipment - Other than Meters	6,369,040	6,825,740	3.94	280,732

COLUMBIA GAS OF PENNSYLVANIA, INC.

SPANOS REBUTTAL_TABLE 2. CALCULATION OF DEPRECIATION ACCRUALS FOR THE THIRTEEN MONTHS ENDED JUNE 30, 2014

	Depreciable Group	Original Cost at May 31, 2013	Original Cost at June 30, 2014	Composite Accrual Rate	13 Month Accrual Amount
	(1)	(2)	(3)	(4)	(5)
	Other Equipment				
387	General	138,546	138,546	9.04	13,527
387.4	Customer Information Services	1,054,442	1,054,442	4.58	52,157
	Total Account 387	1,192,988	1,192,988	5.04	65,684
	Total Distribution Plant	1,265,643,242	1,430,878,042	2.26	32,590,352
GENERAL PLANT					
390.1	Structures and Improvements - Communications	49,821	49,821	0.49	264
	Office Furniture and Equipment				
391.1	Furniture	2,750,361	2,313,305	3.07	83,945
391.11	Equipment	53,582	38,327	3.17	1,573
391.12	Information Systems	2,603,567	2,395,760	15.08	407,105
	Total Account 391	5,407,509	4,747,392	8.39	492,623
392	Transportation Equipment - Trailers	195,040	180,766	8.05	16,336
393	Stores Equipment	17,116	16,675	2.41	440
	Tools, Shop and Garage Equipment				
394	Equipment	10,549,745	11,065,418	3.60	420,199
394.12	CNG Facilities	1,953,498	1,953,498	0.07	1,477
	Total Account 394	12,503,243	13,018,916	3.03	421,676
395	Laboratory Equipment	78,986	71,550	5.81	4,723
396	Power Operated Equipment	1,772,200	1,772,200	2.83	54,166
	Communication Equipment				
397.1	Telephone	976,525	1,058,770	8.74	96,058
397.24	Radio	2,392,491	2,527,212	7.59	201,639
397.5	Telemetering	895,260	953,020	5.24	52,299
	Total Account 397	4,264,276	4,539,003	7.41	349,996
398	Miscellaneous Equipment	564,621	1,275,704	6.41	63,701
	Total General Plant	24,852,812	25,672,028	5.08	1,403,925
	Subtotal Depreciable Plant	1,295,456,971	1,462,528,286		34,130,478
AMORTIZABLE PLANT					
303	Intangible plant	9,317,538	12,894,592	*	1,733,980
305	Structures and Improvements				
362	Gas Holders				
362.1	Environmental Remediation				
374.2	Land, Other Distribution Systems	480,964	480,964		
375.71	Structures and Improvements - leased	1,031,960	1,031,960	*	263,453
389.2	Land and Land Rights - Land Rights				
	Subtotal Amortizable Plant	10,830,461	14,407,516		1,997,433
NONDEPRECIABLE PLANT		172,413	172,413		
	Total Gas Plant	1,306,459,845	1,477,108,215		36,127,911

* Prorated accruals based on individual asset amortization
** Future Test Year accrual rate utilized to calculate Future Rate Year annual accrual.

COLUMBIA GAS OF PENNSYLVANIA, INC.

SPANOS REBUTAL_TABLE 3. BRINGFORWARD TO MAY 31, 2013, OF THE BOOK RESERVE AS OF MAY 31, 2012

Account	Book Reserve as of May 31, 2012	+ Depreciation Accruals	+ Amortization of Net Salvage	- Projected Retirements	+ Projected Gross Salvage	- Projected Cost of Removal	+ Acquisitions	- Adjustments	= Reserve at End of Period	Book Reserve as a Percent of Original Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
350.20	1,931								1,931	99.94
351.00	594,787	41,778							636,565	42.01
352.01	799,118								799,118	100.00
352.02	168,680								168,680	100.00
352.10	204,205	124							204,329	98.74
353.00	405,288								405,288	100.00
354.00	583,845			97,400					486,445	83.29
355.00	123,010								123,010	100.00
374.40	583,161	31,630	561	6,200		2,542			606,610	33.17
374.50	1,404,491	43,969	189						1,448,649	44.82
375.34	705,338	64,473	25,852	35,100		27,729			732,834	29.70
375.60	66,155	1,263	1,212						68,630	78.26
375.70	1,961,879	135,858	(151,813)	39,800	28,258	1,592			1,932,790	57.67
375.80	4,943	355							5,298	32.08
376.00	154,176,018	14,343,386	1,258,126	7,637,700		2,291,310			159,848,520	25.05
378.00	5,499,760	506,846	51,623	113,500		24,970			5,919,759	37.85
379.10	82,302	5,567	461						88,330	57.43
380.00	89,666,071	8,116,332	2,716,522	2,911,000		2,183,250			95,404,675	34.38
381.00	13,565,893	802,087	(43,152)	82,500	4,950	(825)			14,248,103	44.39
381.10	883,493	1,543,882		112,200					2,315,175	73.08
382.00	9,422,647	629,911	(5)	158,600					9,893,953	32.97
383.00	2,502,698	235,278	214	71,300		1,426			2,665,464	31.71
384.00	2,630,837	75,750	224						2,706,811	69.70
385.00	2,712,393	244,857	33,651	25,200		5,544			2,960,157	49.46
387.00	35,952	12,525	5,865						54,342	70.82
387.40	426,954	48,293	1,407						476,654	38.59
390.10	45,841	244							46,085	12.85
391.10	2,372,391	87,233		190,807					2,268,817	75.77
391.11	27,561	1,639		9,223					19,977	58.52
391.12	912,994	375,241		200,939					1,087,296	132.47
392.00	134,490	16,768	(5,011)	26,506	6,627				126,367	53.53
393.00	14,682	413							15,095	81.79
394.00	4,476,313	372,909	(1,233)	185,665	1,857				4,664,181	50.13
394.12	1,948,970	1,367							1,950,337	99.84
395.00	49,301	4,619		1,040					52,880	58.06
396.00	1,585,180	50,153	(30,776)						1,604,557	81.70
397.10	865,062	91,489	493	163,147	4,894	4,894			793,897	66.27
397.24	1,846,155	180,051							2,026,206	80.33
397.50	604,873	46,523							651,396	76.27
398.00	266,953	30,014	4,855	116,218		26,730			158,874	44.62
	304,362,615	28,142,827	3,869,265	12,184,045	46,586	4,569,162	0	0	319,668,085	

COLUMBIA GAS OF PENNSYLVANIA, INC.

SPANOS REBUTAL_TABLE 3. BRINGFORWARD TO MAY 31, 2013, OF THE BOOK RESERVE AS OF MAY 31, 2012

Account	Book Reserve as of May 31, 2012		Depreciation Accruals		Amortization of Net Salvage		Projected Retirements		Projected Gross Salvage		Projected Cost of Removal		Acquisitions		Adjustments		Reserve at End of Period	Book Reserve as a Percent of Original Cost
(1)	(2)	+	(3)	+	(4)	-	(5)	+	(6)	-	(7)	+	(8)	-	(9)	=	(10)	(11)
Amortizable Plant																		
303.00	3,593,871		1,197,758				1,104,622										3,687,007	57.52
305.00	(1,658)																(1,658)	
362.00	(582)																(582)	
362.10	(2,183,099)				647,812						450,000						(1,985,287)	
374.20	(32,671)				2,473												(30,198)	
375.71	453,695		254,775														708,470	
389.20	39																39	0.00
	1,829,595		1,452,533		650,285		1,104,622		0		450,000		0		0		2,377,791	
Nondepreciable Plant	0																0	
TOTAL	306,192,210		29,595,360		4,519,550		13,288,667		46,586		5,019,162		0		0		322,045,876	

COLUMBIA GAS OF PENNSYLVANIA, INC.

SPANOS REBUTTAL_TABLE 4. BRINGFORWARD TO JUNE 30, 2014 OF THE BOOK RESERVE AS OF MAY 31, 2013

Account	Book Reserve as of May 31, 2013	+ Depreciation Accruals	+ Amortization of Net Salvage	- Projected Retirements	+ Projected Gross Salvage	- Projected Cost of Removal	+ Acquisitions	- Adjustments	= Reserve at End of Period	Book Reserve as a Percent of Original Cost
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)
350.20	1,931								1,931	99.94
351.00	636,565	45,120							681,685	44.99
352.01	799,118								799,118	100.00
352.02	168,680								168,680	100.00
352.10	204,329	134							204,463	98.80
353.00	405,288								405,288	100.00
354.00	486,445	90,947		82,700					494,692	84.70
355.00	123,010								123,010	100.00
374.40	606,610	35,665	877	7,900		3,239			632,013	34.56
374.50	1,448,649	47,487	189						1,496,325	46.29
375.34	732,834	79,208	27,727	30,800		24,332			784,637	31.80
375.60	68,630	1,364	1,212						71,206	81.20
375.70	1,932,790	160,214	(13,699)	19,200	13,632	768			2,072,969	61.86
375.80	5,298	383							5,681	34.40
376.00	159,848,520	17,719,030	1,504,519	9,292,000		2,787,600			166,992,469	26.17
378.00	5,919,759	588,345	43,555	99,400		21,868			6,430,391	41.12
379.10	88,330	6,013	376						94,719	61.59
380.00	95,404,675	9,878,770	2,509,521	3,499,500		2,624,625			101,668,841	36.64
381.00	14,248,103	899,298	(44,390)	118,100	7,086	(1,181)			14,993,178	46.72
381.10	2,315,175	1,740,673		27,200					4,028,648	127.17
382.00	9,893,953	725,891	(6)	191,200					10,428,638	34.75
383.00	2,665,464	279,786	492	81,600		1,632			2,862,510	34.06
384.00	2,706,811	81,809	1						2,788,621	71.80
385.00	2,960,157	280,732	26,685	37,300		8,206			3,222,068	53.84
387.00	54,342	13,527	5,865						73,734	96.10
387.40	476,654	52,157	1,407						530,218	42.93
390.10	46,085	264							46,349	12.92
391.10	2,268,817	83,945		437,655					1,915,107	63.96
391.11	19,977	1,573		16,155					5,395	15.80
391.12	1,087,296	407,105		261,307					1,233,094	150.23
392.00	126,367	16,336	(4,786)	14,273					123,644	52.38
393.00	15,095	440		442					15,093	81.78
394.00	4,664,181	420,199	(1,497)	188,327	423				4,894,979	52.61
394.12	1,950,337	1,477							1,951,814	99.91
395.00	52,880	4,723		7,436					50,167	55.09
396.00	1,604,557	54,166	(23,125)						1,635,598	83.28
397.10	793,897	96,058	493	5,914	512	512			884,534	73.84
397.24	2,026,206	201,639		23,358					2,204,487	87.40
397.50	651,396	52,299							703,695	82.40
398.00	158,874	63,701	7,093	20,917		5,612			203,139	57.05
	319,668,085	34,130,478	4,042,509	14,462,684	21,653	5,477,213	0	0	337,922,828	

COLUMBIA GAS OF PENNSYLVANIA, INC.

SPANOS REBUTTAL_TABLE 4. BRINGFORWARD TO JUNE 30, 2014 OF THE BOOK RESERVE AS OF MAY 31, 2013

Account	Book Reserve as of May 31, 2013		Depreciation Accruals		Amortization of Net Salvage		Projected Retirements		Projected Gross Salvage		Projected Cost of Removal		Acquisitions		Adjustments		Reserve at End of Period	Book Reserve as a Percent of Original Cost
(1)	(2)	+	(3)	+	(4)	-	(5)	+	(6)	-	(7)	+	(8)	-	(9)	=	(10)	(11)
Amortizable Plant																		
303.00	3,687,007		1,733,980				1,786,645										3,634,342	56.70
305.00	(1,658)																(1,658)	
362.00	(582)																(582)	
362.10	(1,985,287)				734,812						300,000						(1,550,475)	
374.20	(30,198)				5,887												(24,311)	
375.71	708,470		263,453														971,923	
389.20	39																39	0.00
	2,377,791		1,997,433		740,699		1,786,645		0		300,000		0		0		3,029,278	
Nondepreciable Plant	0																0	
TOTAL	322,045,876		36,127,911		4,783,208		16,249,329		21,653		5,777,213		0		0		340,952,106	

COLUMBIA GAS OF PENNSYLVANIA, INC.

SPANOS REBUTTAL_TABLE 5. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT JUNE 30, 2014

	Depreciable Group	SURVIVOR CURVE		Original Cost at June 30, 2014	Book Reserve	Future Book Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Composite Remaining Life
	(1)	(2)		(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
DEPRECIABLE PLANT									
UNDERGROUND STORAGE PLANT									
350.2	Rights-of-Way	SQUARE	*	1,932	1,931	1	0	-	-
351	Compressor Station Structures	65-R2.5	*	1,476,260	681,685	794,575	39,703	2.69	20.0
	Wells								
352.01	Construction	SQUARE	*	799,134	799,118	16	1	-	16.0
352.02	Equipment	45-S2.5	*	168,680	168,680	0	0	-	-
	Total Account 352			967,813	967,798	16	1		
352.1	Storage Leaseholds and Rights	SQUARE	*	206,941	204,463	2,478	118	0.06	21.0
353	Lines	50-S1.5	*	405,288	405,288	0	0	-	-
354	Compressor Station Equipment	50-R2.5	*	2,796,973	494,692	2,302,281	120,372	4.30	19.1
355	Measuring and Regulating Equipment	37-R1.5	*	123,010	123,010	0	0	-	-
	Total Underground Storage Plant			5,978,217	2,878,867	3,099,351	160,194	2.68	
DISTRIBUTION PLANT									
	Land and Land Rights								
374.4	Land Rights	65-R3		2,024,995	632,013	1,392,982	33,952	1.68	41.0
374.5	Rights-of-Way	75-S4		3,233,039	1,496,325	1,736,714	43,835	1.36	39.6
	Total Account 374			5,258,034	2,128,338	3,129,696	77,787	1.48	
	Structures and Improvements								
375.34	Measuring and Regulating	60-R1.5		3,522,257	784,637	2,737,620	80,345	2.28	34.1
375.6	Industrial Meas and Reg	50-R1.5		87,692	71,206	16,486	1,033	1.18	16.0
375.7	Other Distribution System								
	Distribution System Structures	90-R1	*	2,490,167	1,756,021	734,147	56,371	2.26	13.0
	Other Buildings	33-S1		1,660,081	316,948	1,343,133	60,653	3.65	22.1
	Total Account 375.70			4,150,247	2,072,969	2,077,280	117,024	2.82	17.8
375.8	Communication Structures			16,515	5,681	10,834	342	2.07	31.7
	Total Account 375			7,776,712	2,934,493	4,842,220	198,744	2.56	

COLUMBIA GAS OF PENNSYLVANIA, INC.

SPANOS REBUTTAL_TABLE 5. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT JUNE 30, 2014

	Depreciable Group	SURVIVOR CURVE		Original Cost at June 30, 2014	Book Reserve	Future Book Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Composite Remaining Life
	(1)	(2)		(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
376	Mains								
	Cast Iron	72-R1.5	*	16,180	12,317	3,863	378	2.34	10.20
	Bare Steel	72-R1.5	*	64,216,575	46,870,152	17,346,423	1,636,263	2.55	10.6
	Other	72-R1.5		847,053,421	120,110,000	726,943,421	16,580,055	1.96	43.8
	Total Account 376			911,286,175	166,992,469	744,293,707	18,216,696	2.00	
378	Meas and Reg Equipment - General	45-R0.5		19,462,757	6,430,391	13,032,366	544,445	2.80	23.9
379.1	Meas and Reg Equipment - City Gate	35-S2.5		153,794	94,719	59,075	5,023	3.27	11.8
380	Services								
	Bare Steel	50-R0.5	*	722,594	672,547	50,047	5,637	0.78	8.90
	Other	50-R0.5		373,279,218	100,996,294	272,282,924	10,367,489	2.78	26.3
	Total Account 380			374,001,812	101,668,841	272,332,971	10,373,126	2.77	
381	Meters	43-S1.5		34,301,875	14,993,178	19,308,697	826,447	2.41	23.4
381.1	Meters - AMR	15-S2.5		20,543,303	4,028,648	16,514,655	1,564,711	7.62	10.6
382	Meter Installations	55-R2.5		35,468,816	10,428,638	25,040,178	701,529	1.98	35.7
383	House Regulators	40-S2		10,741,263	2,862,510	7,878,753	279,136	2.60	28.2
384	House Regulator Installations	35-S3		3,864,772	2,788,621	1,076,151	72,183	1.87	14.9
385	Industrial Meas and Reg Equipment - Other than Meters	30-R0.5		6,825,740	3,222,068	3,603,672	243,187	3.56	14.8
	Other Equipment								
387	General	30-R0.5		138,546	73,734	64,812	4,110	2.97	15.8
387.4	Customer Information Services	25-R2.5		1,054,442	530,218	524,224	40,270	3.82	13.0
	Total Account 387			1,192,988	603,952	589,036	44,380	3.72	
	Total Distribution Plant			1,430,878,042	319,176,866	1,111,701,177	33,147,394	2.32	
GENERAL PLANT									
390.1	Structures and Improvements - Communications	40-R2.5		49,821	46,349	3,472	229	0.46	15.2
	Office Furniture and Equipment								
391.1	Furniture	20-SQ		2,313,305	1,915,107	398,198	85,043	3.68	4.7
391.11	Equipment	15-SQ		38,327	5,395	32,932	2,660	6.94	12.4
391.12	Information Systems	5-SQ		2,395,760	1,233,094	1,162,666	521,011	21.75	2.2
	Total Account 391			4,747,392	3,153,596	1,593,796	608,714	12.82	

COLUMBIA GAS OF PENNSYLVANIA, INC.

SPANOS REBUTTAL_TABLE 5. ESTIMATED SURVIVOR CURVES, ORIGINAL COST, BOOK RESERVE AND CALCULATED ANNUAL DEPRECIATION ACCRUALS RELATED TO GAS PLANT AT JUNE 30, 2014

	Depreciable Group	SURVIVOR CURVE	Original Cost at June 30, 2014	Book Reserve	Future Book Accruals	Calculated Annual Accrual Amount	Calculated Annual Accrual Rate	Composite Remaining Life
	(1)	(2)	(3)	(4)	(5)	(6)	(7)=(6)/(3)	(8)=(5)/(6)
392	Transportation Equipment - Trailers	15-SQ	180,766	123,644	57,122	14,658	8.11	3.9
393	Stores Equipment	20-SQ	16,675	15,093	1,582	400	2.40	4.0
	Tools, Shop and Garage Equipment							
394	Equipment	25-SQ	11,065,418	4,894,979	6,170,439	414,777	3.75	14.9
394.12	CNG Facilities	12-S1.5	1,953,498	1,951,814	1,684	608	0.03	2.8
	Total Account 394		13,018,916	6,846,793	6,172,123	415,385	3.19	
395	Laboratory Equipment	20-SQ	71,550	50,167	21,383	2,589	3.62	8.3
396	Power Operated Equipment	12-L3	1,772,200	1,635,598	136,602	41,464	2.34	3.3
	Communication Equipment							
397.1	Telephone	10-SQ	1,058,770	884,534	174,236	62,959	5.95	2.8
397.24	Radio	15-SQ	2,527,212	2,204,487	322,725	142,699	5.65	2.3
397.5	Telemetering	17-R3	953,020	703,695	249,325	41,163	4.32	6.1
	Total Account 397		4,539,003	3,792,716	746,286	246,821	5.44	
398	Miscellaneous Equipment	15-SQ	1,275,704	203,139	1,072,565	84,325	6.61	12.7
	Total General Plant		25,672,028	15,867,095	9,804,931	1,414,585	5.51	
	Subtotal Depreciable Plant		1,462,528,286	337,922,828	1,124,605,459	34,722,173	2.37	
AMORTIZABLE PLANT								
303	Intangible plant		12,894,592	3,634,342	9,260,250	1,630,608 **		
305	Structures and Improvements			(1,658)				
362	Gas Holders			(582)				
362.1	Environmental Remediation			(1,550,475)				
374.2	Land, Other Distribution Systems		480,964	(24,311)				
375.71	Structures and Improvements - leased		1,031,960	971,923	60,037	182,501 **		
389.2	Land and Land Rights - Land Rights			39				
	Subtotal Amortizable Plant		14,407,516	3,029,278	9,320,287	1,813,109		
NONDEPRECIABLE PLANT			172,413					
	Total Gas Plant		1,477,108,215	340,952,106	1,133,925,746	36,535,282		

* Indicates the use of an interim survivor curve and retirement date.
** Accrual rate based on individual asset amortization.

COLUMBIA STATEMENT NO. 106-R

2-13-13
Hbg SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission ,	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

NANCY J. D. KRAJOVIC

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. Nancy J. D. Krajovic, Southpointe Industrial Park, 121 Champion Way, Canonsburg, PA 15317

Q. Are you the same Nancy J. D. Krajovic that served direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the direct testimony of witnesses Thomas Catlin, filed on behalf of the Office of Consumer Advocate ("OCA"), James Crist, filed on behalf of the Natural Gas Suppliers ("NGS"), Robert Knecht, filed on behalf of the Office of Small Business Advocate ("OSBA") and Daniel Mumford and Christine Wilson, filed on behalf of the Bureau of Investigation and Enforcement ("I&E"). Additionally, I will discuss a change to the Company's rate base claim and correction of an error identified in the original filing.

Q. What issues will you be addressing in this testimony?

A. I will address the following issues:

- Use of the Fully Forecasted Rate Year ("FFRY")
- Storage Gas Working Capital and Cash Working Capital in the Gas Procurement Charge ("GPC")
- Funding for the Gas Technology Institute ("GTI")
- Customer Account Balances under the Purchase of Receivables Program ("POR") and Customer Assistance Program ("CAP")

- Revised Exhibit 108 – Rate Base

Use of the Fully Forecasted Rate Year (FFRY)

Q. What is the purpose of your rebuttal on the use of the fully forecasted rate year ("FFRY")?

A. Specifically, I disagree with OCA Witness Catlin's contention that the Company has overstated its revenue requirement by reflecting costs at the end of the FFRY. He alleges that use of the FFRY is intended to allow rates to be set to reflect the costs that will be incurred during the first year that the rates will be in effect, but does not cite any supporting authority. In fact, nothing in Act 11 of 2012 that authorized the use of the FFRY points to that conclusion.

Q. Has the Company's presentation of its revenue requirement for the FFRY varied from its presentation in prior future test year cases?

A. No. The Company has used the same techniques of determining revenues, expenses and rate base on an annualized, year-end basis that has been used in prior cases, with the exception that the Company has not included any claim for construction work in progress in rate base.

Q. Would the use of the FFRY as recommended by Mr. Catlin have an impact on the use of the DSIC?

A. Yes. Eligible property subject to DSIC recovery is limited to that not already recovered in base rates. The use of an average FFRY to establish base rates will mean that a significant portion of the total investment during the FFRY will not be recovered via base rates and will therefore be eligible for DSIC recovery prior to the end of the FFRY.

Q. Have you quantified the amount of investment that Mr. Catlin's proposal would remove from base rate recovery?

A. Yes. The Company's FFRY includes DSIC eligible capital of $146,065,000. Please see Exhibit NJDK-1R page 1 of 2 for projected monthly expenditures of DSIC eligible property throughout the FFRY. (Actual construction activity is heavily influenced by weather, dynamic project prioritization and mandatory replacement projects, but operational projections are based on all known commitments and normal weather conditions.) Using an average FFRY as Mr. Catlin has proposed would design rates based upon a rate base plant in service of $1,401,796,427 (Catlin Schedule TSC-5.) The monthly additions shown on Exhibit 108, Schedule 1, demonstrate that a plant in service balance of $1,401,796,427 will be reached when 55.9% of the net additions in December 2013 have been placed into service. Therefore, the DSIC eligible property included in plant in service in FFRY beyond that point in December will not be reflected in base rates. To quantify that amount the projected DSIC eligible plant placed in service from July 2013 through November 2013 plus 55.9% of the DSIC eligible plant projected to be installed December 2013 is deducted from the total DSIC eligible plant included in the FFRY for a remainder of $68,394,482. Please see Exhibit NJDK-1R page 2 of 2.

Q. What does that mean in terms of implementing a DSIC for recovery of eligible property?

A. It means that in order to recover the remaining DSIC eligible plant excluded by the use of an average FFRY, the Company must be able to implement a DSIC

prior to the time it would if rates were based on the test year as proposed by the Company. Any other approach will result in a gap period in which eligible property is neither in a DSIC nor in rate base and will not be until a subsequent rate filing. If the DSIC is to function as it was designed, then the Company should be granted specific authorization to implement a quarterly DSIC to recover property placed in service that is not reflected in base rates, consistent with 66 Pa. Code C.S. as follows:

> **§ 1357. Computation of charge.**
> **(a) Recovery.**--The following shall apply:
> (1) The initial distribution system improvement charge shall be calculated to recover the fixed cost of eligible property that has:
> (i) Not previously been reflected in the utility's rates or rate base.
> (ii) Been placed in service during the three-month period ending one month prior to the effective date of the distribution improvement system charge.

Q. Using the data presented in Exhibit NJDK-1R and comparing it to the average rate year rate base that Mr. Catlin proposes, when would the use of the DSIC be possible after the rates from this proceeding become effective?

A. Based upon the Company's operational projections, and using Mr. Catlin's average rate year proposal, DSIC eligible plant additions would cease to be reflected in rates in mid-December, 2013. Property placed in service in excess of that level in December and additional property placed in service in January and February 2014 would be eligible for DSIC recovery beginning April 1, 2014.

Q. How long would Columbia be able to use a DSIC after that?

A. The next quarterly adjustment to the DSIC would be filed to be effective on July 1, 2014 to recover DSIC eligible plant placed into service in March, April and May of

2014.

Q. Would another quarterly DSIC filing adjustment be submitted to be effective on October 1, 2014?

A. Many factors, including the ultimate determination of base rates in the proceeding, the approved ROE for calculating the DSIC and actual construction activity will impact whether the Company will be able to utilize a DSIC past September 30, 2014. Based on the Company's projected monthly DSIC eligible additions for June, July and August, and using varying inputs for distribution revenues and ROE, the Company estimates the October 1, 2014 DSIC to be just above or just below the statutory 5% cap on distribution revenues recovered through a DSIC. Therefore, under Mr. Catlin's proposal in this case, the DSIC would only support ongoing plant additions placed in service within the first two months (July and August) after the conclusion of the FFRY in this case.

Q. Please explain why the use of the rate base at the end of the FFRY will better support Columbia's infrastructure replacement program.

A. As I noted previously, Mr. Catlin's average rate base will require Columbia to use the DSIC mechanism just to recover the return and depreciation on the investment in the second half of the FFRY. As I explain above, under Mr. Catlin's proposal the Company will likely reach the 5% cap in the first quarter following the FFRY. Accordingly, in order to continue to earn a return and recover depreciation on investment after the FFRY, Columbia would have to file a rate case that would have a FFRY that commences just three months after the FFRY in this case. By using the June 30, 2014 FFRY rate base in this case as the Company

has proposed, Columbia could begin applying the DSIC for investment after the FFRY and potentially delay the time period between general rate increases. Columbia believes that it was the intention of the DSIC mechanism to encourage investment by not requiring companies to file general rate increases as the sole means of recovering accelerated infrastructure replacement. Using the rate base at the end of the FFRY will afford Columbia that opportunity.

Cash Working Capital and Storage Gas Working Capital in the GPC

Q. What is the purpose of your rebuttal testimony on cash working capital and storage gas working capital in the GPC?

A. I will address the recommendations made on this topic by NGS witness James Crist and OSBA witness Robert Knecht.

Q. What specific points in their testimony would you like to address?

A. First, both Mr. Crist and Mr. Knecht observe that no cash working capital relative to the revenues/costs associated with gas supply was included in the calculation of the GPC. As recognized by Mr. Knecht, this reflects the fact that no claim for cash working capital ("CWC") was made in the case.

Q. What other matters raised in regard to storage gas working capital do you want to rebut?

A. Mr. Crist alleges that all of the Company's storage gas working capital costs are associated with gas used to provide default service, not CHOICE® service, and should be allocated to the GPC.

Q. Do you agree with Mr. Crist's allocation of the Company's storage gas working capital costs to the GPC?

A. No. I would like to provide clarification that storage gas working capital is incurred equally for sales service customers and CHOICE® customers and is, therefore, already allocated between sales service and CHOICE® customers through base rates.

Q. Please describe Columbia's CHOICE® average day program.

A. Simply stated Columbia's average day CHOICE® Program requires that NGSs deliver to Columbia each day, through the Pipeline Scheduling Points behind which their customers reside, 1/365th of their customers' normalized annual consumption each day of the year.

Q. Does Columbia's average day CHOICE® Program have a defined annual term?

A. Yes, the average day CHOICE® Program's program year runs August 1st through the following July 31st.

Q. Are there any unique delivery requirements at the beginning of each year?

A. Yes, for the month of August the program requires each NGS to deliver 1/365th of the normalized projected customer's annual usage each day plus ½ of July's consumption prorated over the 31 days of August. Conceptually, at the end of August, the NGS will have a positive gas balance equal to 31 days of average delivery plus ½ of July's consumption less August calendar month customer consumption.

Q. Why does Columbia require an NGS to deliver ½ month of July customer consumption as of August 1?

A. This requirement occurs because gas deliveries are accounted for on a calendar month but customer usage and thus payments to NGSs are measured based on a billing cycle. The billing month of August, on average, will reflect ½ month of July consumption. At the same time that this occurs, the NGS is delivering 1/365th of an annual consumption for each day in August and the customer is consuming gas August 1st through August 31st half of which will be reflected on the September bill.

Q. What happens in the remaining months of the year?

A. The NGS is asked to supply on each day of the year 1/365th of the annual consumption of their current customer group. That annual consumption amount is recalculated each month to account for new customers or customers who have left the NGS's service.

Q. Is there a reconciliation of the NGSs' average day deliveries based on a normalized projected customer's annual usage, and actual consumption over the program year?

A. Yes. Records of deliveries vs. consumption are maintained for each month. At the end of July, the NGSs' deliveries and their customers' billed consumption are trued up. NGSs buy gas quantities from Columbia adequate to zero out the true-up if they have under-delivered for the year or will sell their excess deliver to Columbia if they have over-delivered.

Q. What does this average day program have to do with gas storage?

A. Columbia manages differences between NGS deliveries and their customers' consumption through storage management. By the end of December, the suppliers' cumulative deliveries are less than customers' cumulative requirements, and Columbia must call upon its inventory of gas in storage to make up the deficiency

between cumulative NGS deliveries and customers' requirements. 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 needed supplies to meet CHOICE® customer requirements in years in which customer usage exceeds average deliveries.

Q. Can you provide an analysis that depicts the annual cycle of over and under supply?

A. Yes. Exhibit NJDK-2R demonstrates that NGSs will over-deliver in August, September and October and will under-deliver in the months from November through April, followed by another period of over-delivery from May through July.

Q. What else does the analysis show?

A. The analysis clearly demonstrates that over deliveries made August through October are quickly offset by under deliveries November through March. The under delivery in the heating season erodes away any over deliveries on a net basis by January. In fact, the NGS is left owing Columbia gas in January and this continues until July when the true up again occurs. So the NGS owes the Company gas 6 months of the year. During this time, the CHOICE® customer and its NGS are both relying upon Columbia's gas in storage and its purchases of such gas to allow the average day program to operate.

Q. Please summarize the NGS's position throughout this cycle.

A. While this will vary by month based on when an NGS first begins serving a customer, on average, using normal weather assumptions, the NGS is projected to have an average monthly under-delivered balance of .41 therms for each residential CHOICE® customer.

Q. Does this mean that other than .41 therms for every residential CHOICE® customer that storage gas is solely for the use of sales customers?

A. No. This analysis looks only at an average residential customer. For example, CHOICE® NGSs will have under-delivered up to approximately 1,420,962 therms cumulatively in March for residential customers alone without consideration for commercial customers.

Q. How does the average day program compare to the other CHOICE® programs that may require NGSs to deliver to a load curve?

A. If NGSs were required to deliver to a load curve, they would need to deliver volumes of gas to meet a customer's requirements every month of the year, and would not be allowed the delivery deficits under the average day program.

Q. Aside from providing winter requirements and daily and monthly balancing, are there other benefits that Columbia's storage gas provides to the CHOICE® NGSs and therefore their customers?

A. Yes. Columbia's average day program does not require CHOICE® NGSs to meet design day or design winter conditions because CHOICE® NGSs deliver gas to meet their customers' normalized demand. Columbia, as the Supplier of Last Resort maintains storage capacity and fills that storage capacity by the beginning of the winter period in order to meet customer requirements in the event of a colder than normal winter. Therefore, a portion of storage gas must be available to serve the requirements of CHOICE® customers demand in excess of normalized annual requirements upon which NGS deliveries are based. Finally, Columbia has an open enrollment policy for CHOICE®. That is, the NGSs are free to sign up customers in

any month of the year and are not restricted to signups matched to the beginning of the program year. To provide this opportunity for open enrollment, Columbia must operate its storage to have sufficient gas supplies to serve each firm service customer throughout the winter, without regard to when the customer elects CHOICE® service and consequently NGSs begin delivery of supplies. Without gas storage working capital invested by Columbia, NGSs could not have the benefit of an average day mechanism and year round customer enrollment.

Q. Can you provide a further example of how gas storage allows Columbia to offer year round enrollment and an average day mechanism?

A. Yes. My Exhibit NJDK-2 shows the balance by month assuming a customers is signed up in August. If a customer signs up in December, the NGS will have no excess deliveries in earlier months. Their average day deliveries will thus be deficient throughout the remainder of the CHOICE® year, until they are cashed out in July. Columbia's storage gas allows the NGS to sign up the customer without requiring delivery of a lump sum gas supply (or purchase of gas from Columbia) up front to begin CHOICE® service.

Q. Do you agree with Mr. Crist's assertion that simply because there is a gas storage working capital cost it necessarily should be charged to sales service customers?

A. No. It is clear that even if all customers were in the CHOICE® program, it would be necessary for Columbia to continue making gas storage working capital investment to serve CHOICE® customers under the average day program, in order to continue to meet customers' requirements throughout the winter until the July cash-out.

Q. Does OSBA witness Knecht state an opinion in regard to the allocation of gas storage working capital between sales and CHOICE® customers in view of the Company's average day program?

A. Yes. In his testimony, Mr. Knecht states that he understands and accepts the Company's logic for excluding storage gas working capital from the GPC calculation. He further testifies, "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."

Q. Mr. Knecht proposes, however, that storage gas working capital costs related to sales customers be included in the GPC and that storage gas working capital costs related to CHOICE® customers be billed to CHOICE® customers or CHOICE® NGSs, who could then "pass those on to their own customers as they see fit." How do you respond to his suggestion?

A. Mr. Knecht is unnecessarily complicating this matter. Because Mr. Knecht agrees that these costs properly are recovered from CHOICE® customers, they should remain in base rates. Mr. Knecht's proposal to bill the CHOICE® NGSs presents transition issues, as he has acknowledged, because the NGSs may have existing contracts with their customers that would prohibit them from recovering such costs. Furthermore, Mr. Knecht's suggestion of billing such costs directly to CHOICE® customers works to create an unlevel playing field by practically guaranteeing customer confusion as to how such a billed cost would be included in comparing rates. Lastly, Mr. Knecht's proposal creates additional uncertainty and a

practically impossible issue related to how such costs would be allocated given year round enrollment.

The Company therefore rejects the proposition to bill the CHOICE® NGSs for the storage gas working capital costs related to the CHOICE® customers. The Company further disagrees with the need to remove the storage gas working capital costs from base rates, include one portion in the GPC and then create another component to add to the CHOICE® customers' bills and incur all of the associated administrative costs to accomplish that billing change when the end result is the same as leaving those costs in rate base.

Q. Mr. Knecht states the following, "I recommend that Columbia give the NGSs the option of either (a) retaining the existing storage fill timing requirements and paying the SGWC, 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." Do you have any comments on Mr. Knecht's recommendation?

A. Yes I do. Mr. Knecht's recommendation that simply moving the start of the program year to April does not change an NGS's delivery obligation, and thus has no impact on the financing costs of their delivery requirements. NGSs have the same daily delivery requirements regardless of whether the program year begins in April or in August. Operationally, changing the program year start date to April from August does not change Columbia's management of CHOICE® NGS deliveries and does not change the start of storage injections. Furthermore, Mr. Knecht's proposal provides no benefit for the fundamental utilization of storage supplies

purchased by Columbia related to year round enrollment or satisfaction of colder than normal requirements. The recommendation also would require any NGS moving to an April date to make a substantial delivery of supplies, or cash in payment, to offset the delivery deficit at the end of March (14.65 Dth per customer, and possibly more depending upon sign up date). Lastly, Mr. Knecht's proposal adds significant uncertainty and variability into the annual true-up process by moving the true-up date to a point in the year with greater weather variability that significantly affects the true-up volumes.

Q. Mr. Knecht further points out that, under the current base rate allocation of gas storage working capital, SGDS customers are paying for a service they do not receive. How does the Company respond?

A. The Company does not disagree that the distribution rates charged to customers served under Rates SGSS, SCD and SGDS are the same. For the reasons discussed previously in my testimony, it is the Company's position that base rate recovery of storage gas working capital continues to be appropriate given that both sales service and CHOICE® customers are served by that investment. However, in order to address the issue that Mr. Knecht has identified with regard to the Rate SGDS customers, the Company, upon final determination of the revenue requirement and revenue allocation in this case, will remove storage gas working capital costs from the rate design for Rate SGDS and reallocate those costs to Rates SGSS and SCD.

Q. Finally, Mr. Knecht recommends that the GPC be billed as a percentage of the PGC rather than a per therm fee. Does the Company agree with this recommendation?

A. No. 52 Pa. Code § 62.222. Definitions states:

The following words and terms, when used in this subchapter, have the following meanings, unless the context clearly indicates otherwise:

* * *

GPC—Gas procurement charge—An element of the PTC [price to compare], expressed on a per MCF or dekatherms (Dth) basis, that reflects an NGDC's natural gas procurement costs and removed from the NGDC's base rate and recovered through a separate charge.

Funding for GTI

Q. What is the purpose of your rebuttal testimony on GTI funding?

A. The purpose of my testimony is to address Ms. Wilson's incorrect characterization of Columbia's recent GTI funding as well as her quantification of "minimum funding."

Q. How does Ms. Wilson characterize Columbia's funding to GTI in recent years?

A. Ms. Wilson contrasts the Company's statement that it funded GTI at the level of $165,000 with a characterization that refers to Columbia's funding of GTI in recent years as significantly below $150,000, based upon the Company's response to I&E-RE-115-D.

Q. Is that characterization correct?

A. No. Columbia did indeed fund GTI at $165,000 as stated in my direct testimony. That most recent funding, which occurred in 2012 during the historic test year for this case, was not included in the response to I&E-RE-115-D, as the interrogatory only requested funding in 2009, 2010 and 2011.

Q. Ms. Wilson claims that GTI officially lowered minimum dues to $150,000 in 2008 based upon information provided by the Company in response to OCA II-024. Do you agree with that statement?

A. Yes.

Q. Does that minimum apply to Columbia?

A. No. GTI's funding formula for Operations Technology Development is $0.50 per meter, with a minimum of $150,000, triggered when a member has less than 300,000 meters. Columbia is not subject to that trigger because Columbia's meter count far exceeds 300,000. Columbia's claim for GTI funding is accurate based upon a fee of $0.50 per customer for 415,347 customers.

Q. What is your recommendation with regard to Ms. Wilson's downward adjustment to GTI funding expense?

A. I recommend that the adjustment be rejected as it was based on an inaccurate characterization of Columbia's recent funding of GTI as well as a misinterpretation of GTI's minimum funding provisions.

Customer Account Balances under the POR Program and CAP

Q. What is the purpose of your rebuttal testimony with regard to Customer Account Balances under the POR Program and CAP?

A. Mr. Mumford, on behalf of the Commission's Bureau of I&E, has expressed concerns regarding Columbia's handling of account balances under the POR program and CAP and violations of Commission regulations. I will address these matters in my rebuttal.

Q. Mr. Mumford cites two instances that involved the transfer of account balances older than four years. What is the Company's position on these transfers?

A. Columbia agrees with the comments of Mr. Mumford regarding the incorrect transfer of utility service balances over four years old (Section 56.35 (b) (1)), to active accounts--in these two instances. Columbia also acknowledges that it inappropriately issued a termination notice in one instance that included POR arrears that were over four years old.

Q. Does the Company agree with Mr. Mumford that these two instances are indicative of a larger problem with Columbia's processes?

A. No. First, I note that both of the instances referenced by Mr. Mumford were successfully resolved by Columbia, in cooperation with the Commission's Bureau of Consumer Services. Further, after reviewing Mr. Mumford's comments Columbia would like to describe in greater detail how these two isolated errors occurred, why Columbia does not view them as the same, and how Columbia has already taken steps to resolve his concerns.

Q. Please describe the events surrounding Complaint No. 291587.

A. As described by Mr. Mumford, in this case the Company incorrectly required the payment of a balance from a prior address to establish service at a new address for a customer who was a past participant in the Company's CAP program. The Company viewed this as human error on the part of the Customer Service Representative who had posted the account. Retraining was provided to that employee.

Q. What other steps has Columbia taken to ensure that balances over four years are not brought forward to new accounts?

A. In August of 2012, a programming change was implemented to block the auto transfer of any balance older than four years old to a new account.

Q. Please describe the circumstances surrounding the other complaint.

A. Complaint No. 3001682 involved an active account where POR balances older than four years were incorrectly transferred to an active account during entry into CAP. Although the common denominator with the other complaint was the transfer of a balance older than four years, they are distinct incidents in that they occurred as part of two unrelated processes – one to establish service and the other in the management of a CAP account.

Q. Has the Company taken any action in response to Complaint No. 3001682?

A. Yes. Because the nature of the CAP addresses the individual needs of our customers, CAP account management remains a manual process. However, to ensure that only less than four-year balances are rolled into the CAP program for appropriate CAP treatment (excluding any pre-2010 POR balance), authority for effecting those transfers no longer resides broadly with Universal Service call center representatives, but is now limited to only one individual who is a CAP program subject matter expert.

Q. Mr. Mumford contends that the Company was slow to identify these two complaints and is concerned that may indicate a broader problem. Do you agree?

A. No. Columbia has reviewed its processes as well as its Commission complaints and violations relative to these sections of the Commission's regulations over the past 4 years and has determined that these were isolated incidents.

Q. Mr. Mumford's comments suggest that Columbia could be double recovering POR arrearages in its four recent base rate cases. Has that occurred?

A. No. When Columbia instituted its CHOICE® program back in the late 1990's, to follow Commission regulations relative to the handling of POR balances, it transferred any unpaid POR balance at 90 days or older with a $250 balance to a miscellaneous revenue account ("MRA") which was ultimately charged off below the line – not added to the uncollectibles expense - and sent to a collection agency. The placement of these balances in an MRA prevented the transfer of unpaid marketer supply balances to any active account. Additionally, the use of the MRA account prevented the transfer of any POR arrears, since utilities cannot terminate for non-basic charges. In fact, as long as Columbia has had a CHOICE® program through 2010, POR write-offs were never recovered through its uncollectible expense account in its base rates.

Q. Mr. Mumford contends that the conventional recovery mechanism for uncollectible expense, i.e., base rate recovery, affords a greater level of scrutiny than the reconciliation of Rider USP expenses. Do you agree?

A. No. While the four base rate cases that Columbia filed in the last five years have certainly afforded a more frequent opportunity than in the past to provide review of Columbia's uncollectible expense recovery, the annual reconciliation of Rider USP mechanism is explicitly subject to Commission audit. Should an audit determine any inappropriate recovery of CAP arrearages, those amounts would be subject to refund to the customers. This type of reconciliation is not available under a base rate case review.

Q. Can you summarize your response to Mr. Mumford's recommendations?

A. Yes. While the Company admits mistakes were made in the two cases cited by Mr. Mumford, its review of processes and BCS complaints provided neither an indication of additional instances of transfers of balances over four years, nor has Mr. Mumford presented any. The Company has programmed an automatic block in its billing system to prevent the manual linkage of balances over four years to active accounts and has made process improvements in the management of CAP accounts to provide the same safeguard there. I have explained that pre-2010 POR arrearages do not become part of the Company's uncollectible expense. Overall, Mr. Mumford's recommendations have already been implemented by the Company and therefore it is not necessary for the Commission to order the Company to undertake those actions.

Revised Exhibit 108 - Rate Base

Q. Are there other matters that you would like to present in your testimony?

A. Yes. I am submitting as Exhibit NJDK-3R a REVISED Exhibit 108 Page 3 of 11.

Q. What changes have been made to this schedule?

A. I have incorporate changes to Accounts 108-111 – Depreciation Reserve, as set forth in Witness Spanos' testimony and to the Deferred Income Tax Accounts as described by Witness Fischer in her testimony.

Q. Does the revised Exhibit 108, Page 3 of 11 reflect the additional $3.2 million capital allocation discussed by other Company witnesses?

A. No. As indicated by Witness Fischer, on January 1, 2013 the American Taxpayer Relief Act of 2012 ("2012 Tax Act") was passed, which extended 50% bonus

depreciation for federal income tax purposes for 2013. The consequence of the change in this case would be a decrease in the revenue requirement sought. Witness Gore has prepared a summary statement of the revenue requirement associated with that additional capital and includes it with his rebuttal testimony as Exhibit JTG-R2, Schedule 5. The Company is preparing a further revised Exhibit 108 that reflects the additional capital and restates all impacted accounts. The revised Exhibit 108 will be supplied to all parties as soon as it is available.

Q. Does this conclude your testimony?

A. Yes, it does.

Monthly Calendar July 2013 - June 2014
Projected DSIC Eligible Additions (In 000s)

Sum of Amount			Est	Est	Est	Est	Est	Est	Est	Est	Est	Est	Est	Est	TOTAL 2014
Class	GPA	Desc 2	201307	201308	201309	201310	201311	201312	201401	201402	201403	201404	201405	201406	
2 Replacement - Age & Condition															
	376	Mains - Leakage Elim	9,041	9,716	10,171	10,008	8,771	7,508	4,689	4,689	6,622	8,272	8,574	8,909	**96,968**
	380	Service Lines - Replaced	2,858	2,858	2,658	2,458	2,058	1,858	1,633	1,633	1,833	2,633	2,833	2,833	**28,140**
	380	Customer Service Lines Replaced	945	845	745	695	595	595	345	345	645	795	795	895	**8,240**
	381	Meters	115	100	100	90	90	75	30	30	75	85	85	125	**1,000**
	382	Meter Install - Replaced	145	145	120	110	110	115	55	60	90	110	110	130	**1,300**
	383	House Regulators -Replace	50	50	30	30	30	30	20	20	25	35	40	40	**400**
2 Replacement - Age & Condition Total			13,153	13,713	13,823	13,390	11,653	10,180	6,771	6,776	9,289	11,929	12,436	12,931	**136,048**
3 Replacement - Mandatory	376	Mains - Street Improvement	873	676	440	817	(131)	206	44	44	88	220	678	1,029	**4,984**
3 Replacement - Mandatory Total			873	676	440	817	(131)	206	44	44	88	220	678	1,029	**4,984**
4 Betterment	376	Mains - Service Improvement	400	550	650	641	759	472	229	129	158	30	123	542	**4,683**
	381.1	CPA AMR Project	45	91	15	10	1	54	101	0	0	0	21	12	350
4 Betterment Total			445	641	665	651	760	526	330	129	158	30	144	554	**5,033**
Monthly DSIC Eligible Additions			**14,471**	**15,030**	**14,928**	**14,859**	**12,282**	**10,912**	**7,145**	**6,949**	**9,535**	**12,179**	**13,259**	**14,514**	**146,065**

Columbia Gas of Pennsylvania, Inc.
Calculation of DSIC Eligible Property Excluded from Recovery
Under Average July 2013 - June 2014 FFRY Rate Base

Total Projected DSIC Eligible Plant in Service installed July 2013 - June 2014				$146,065,000
Monthly Additions (from NJDK-1R, page 1 of 2):				
July			14,471,428	
August			15,030,128	
September			14,927,864	
October			14,858,762	
November			12,282,430	
December	10,912	55.9%	6,099,906	
Projected DSIC Eligible Plant in Service Reflected in Average Rate Base				77,670,518
Projected DSIC Eligible Plant in Service NOT Reflected in Average Rate Base				$68,394,482

COLUMBIA GAS OF PENNSYLVANIA, INC. - Proposed Delivery
TME June 2014

Ln. No.		Month	Year 1												Year 2												Mktr Adv/(Dis) Avg Aug-Jul	Mktr Adv/(Dis) Avg Pre-Aug
			Jan 31	Feb 28	Mar 31	Apr 30	May 31	June 30	July 31	Aug 31	Sep 30	Oct 31	Nov 30	Dec 31	Annual 365	Jan 31	Feb 28	Mar 31	Apr 30	May 31	June 30	July 31	Aug 31	Sep 30	Oct 31	Nov 30	Dec 31	Annual		
1	*Typical Residential Customer Usage*		16.44	15.96	13.51	9.13	4.28	2.31	1.49	1.44	1.50	2.71	6.20	11.09	86.06	16.44	15.96	13.51	9.13	4.28	2.31	1.49	1.44	1.50	2.71	6.20	11.09	86.06		
2	Mktr Deliveries for January sign-up	J		6.60	7.31	7.07	7.31	7.07	7.31	7.31	7.07	7.31	7.07	7.31		7.31	6.60	7.31	7.07	7.31	7.07	7.31								
3	CPA Paid for January sign-up	J	7.98	14.74	11.32	6.71	3.30	1.90	1.47	1.47	2.11	4.46	8.65	13.77		16.20	14.74	11.32	6.71	3.30	1.90	1.47								
4	July True-up Made in August									5.47																				
5	Mktr Advantage / (Disadvantage)		7.98	16.11	20.12	19.76	15.74	10.57	4.72	(6.59)	(11.56)	(14.41)	(12.84)	(6.38)		2.51	10.64	14.65	14.28	10.27	5.09	(0.75)							0.41	13.57
6	Mktr Deliveries for February sign-up	F			7.31	7.07	7.31	7.07	7.31	7.31	7.07	7.31	7.07	7.31		7.31	6.60	7.31	7.07	7.31	7.07	7.31								
7	CPA Paid for February sign-up	F		6.76	11.32	6.71	3.30	1.90	1.47	1.47	2.11	4.46	8.65	13.77		16.20	14.74	11.32	6.71	3.30	1.90	1.47								
8	July True-up Made in August									(3.88)																				
9	Mktr Advantage / (Disadvantage)			6.76	10.77	10.40	6.38	1.21	(4.63)	(6.59)	(11.56)	(14.41)	(12.84)	(6.38)		2.51	10.64	14.65	14.28	10.27	5.09	(0.75)							0.41	5.15
10	Mktr Deliveries for March sign-up	M				7.07	7.31	7.07	7.31	7.31	7.07	7.31	7.07	7.31		7.31	6.60	7.31	7.07	7.31	7.07	7.31								
11	CPA Paid for March sign-up	M			4.57	6.71	3.30	1.90	1.47	1.47	2.11	4.46	8.65	13.77		16.20	14.74	11.32	6.71	3.30	1.90	1.47								
12	July True-up Made in August									(10.09)																				
13	Mktr Advantage / (Disadvantage)				4.57	4.20	0.18	(4.99)	(10.84)	(6.59)	(11.56)	(14.41)	(12.84)	(6.38)		2.51	10.64	14.65	14.28	10.27	6.00	(0.75)							0.41	(1.38)
14	Mktr Deliveries for April sign-up	A					7.31	7.07	7.31	7.31	7.07	7.31	7.07	7.31		7.31	6.60	7.31	7.07	7.31	7.07	7.31								
15	CPA Paid for April sign-up	A				2.14	3.30	1.90	1.47	1.47	2.11	4.46	8.65	13.77		16.20	14.74	11.32	6.71	3.30	1.90	1.47								
16	July True-up Made in August									(12.14)																				
17	Mktr Advantage / (Disadvantage)					2.14	(1.87)	(7.05)	(12.89)	(6.59)	(11.56)	(14.41)	(12.84)	(6.38)		2.51	10.64	14.65	14.28	10.27	5.09	(0.75)							0.41	(4.92)
18	Mktr Deliveries for May sign-up	M						7.07	7.31	7.31	7.07	7.31	7.07	7.31		7.31	6.60	7.31	7.07	7.31	7.07	7.31								
19	CPA Paid for May sign-up	M					1.16	1.90	1.47	1.47	2.11	4.46	8.65	13.77		16.20	14.74	11.32	6.71	3.30	1.90	1.47								
20	July True-up Made in August									(9.11)																				
21	Mktr Advantage / (Disadvantage)						1.16	(4.02)	(9.86)	(6.59)	(11.56)	(14.41)	(12.84)	(6.38)		2.51	10.64	14.65	14.28	10.27	5.09	(0.75)							0.41	(4.24)
22	Mktr Deliveries for June sign-up	J							7.31	7.31	7.07	7.31	7.07	7.31		7.31	6.60	7.31	7.07	7.31	7.07	7.31								
23	CPA Paid for June sign-up	J						0.75	1.47	1.47	2.11	4.46	8.65	13.77		16.20	14.74	11.32	6.71	3.30	1.90	1.47								
24	July True-up Made in August									(4.35)																				
25	Mktr Advantage / (Disadvantage)							0.75	(5.10)	(6.59)	(11.56)	(14.41)	(12.84)	(6.38)		2.51	10.64	14.65	14.28	10.27	5.09	(0.75)							0.41	(2.18)
26	Mktr Deliveries for July sign-up	J								7.31	7.07	7.31	7.07	7.31		7.31	6.60	7.31	7.07	7.31	7.07	7.31								
27	CPA Paid for July sign-up	J							0.72	1.47	2.11	4.46	8.65	13.77		16.20	14.74	11.32	6.71	3.30	1.90	1.47								
28	July True-up Made in August									1.47																				
29	Mktr Advantage / (Disadvantage)								0.72	(6.59)	(11.56)	(14.41)	(12.84)	(6.38)		2.51	10.64	14.65	14.28	10.27	5.09	(0.75)							0.41	0.72
30	Mktr Deliveries for August sign-up	A									7.07	7.31	7.07	7.31		7.31	6.60	7.31	7.07	7.31	7.07	7.31	7.31							
31	CPA Paid for August sign-up	A								0.75	2.11	4.46	8.65	13.77		16.20	14.74	11.32	6.71	3.30	1.90	1.47	0.72							
32	July True-up Made in August																													
33	Mktr Advantage / (Disadvantage)									0.75	(4.22)	(7.07)	(5.50)	0.95		9.85	17.98	21.99	21.62	17.61	12.43	6.59	(0.00)						0.41	7.75
34	Mktr Deliveries for September sign-up	S										7.31	7.07	7.31		7.31	6.60	7.31	7.07	7.31	7.07	7.31	7.31	7.07						
35	CPA Paid for September sign-up	S									1.36	4.46	8.65	13.77		16.20	14.74	11.32	6.71	3.30	1.90	1.47	1.47	0.75						
36	July True-up Made in August																													
37	Mktr Advantage / (Disadvantage)										1.36	(1.50)	0.07	6.53		15.42	23.55	27.56	27.19	23.18	18.01	12.16	6.32	(0.00)					0.41	13.96
38	Mktr Deliveries for October sign-up	O											7.07	7.31		7.31	6.60	7.31	7.07	7.31	7.07	7.31	7.31	7.07	7.31					
39	CPA Paid for October sign-up	O										3.10	8.65	13.77		16.20	14.74	11.32	6.71	3.30	1.90	1.47	1.47	2.11	1.36					
40	July True-up Made in August																													
41	Mktr Advantage / (Disadvantage)											3.10	4.67	11.13		20.02	28.15	32.16	31.79	27.78	22.61	16.76	10.92	5.95	(0.00)				0.41	19.82
42	Mktr Deliveries for November sign-up	N												7.31		7.31	6.60	7.31	7.07	7.31	7.07	7.31	7.31	7.07	7.31	7.07				
43	CPA Paid for November sign-up	N											5.55	13.77		16.20	14.74	11.32	6.71	3.30	1.90	1.47	1.47	2.11	4.46	3.10				
44	July True-up Made in August																													
45	Mktr Advantage / (Disadvantage)												5.55	12.00		20.09	29.02	33.04	32.67	28.65	23.48	17.64	11.80	6.83	3.97	(0.00)			0.41	22.55
46	Mktr Deliveries for December sign-up	D														7.31	6.60	7.31	7.07	7.31	7.07	7.31	7.31	7.07	7.31	7.07	7.31			
47	CPA Paid for December sign-up	D												8.22		16.20	14.74	11.32	6.71	3.30	1.90	1.47	1.47	2.11	4.46	8.65	5.55			
48	July True-up Made in August																													
49	Mktr Advantage / (Disadvantage)													8.22		17.11	25.24	29.25	28.89	24.87	19.70	13.85	8.02	3.05	0.19	1.76	-		0.41	20.89

7.64 Avg/Cust

Columbia Gas of Pennsylvania, Inc.
Statement of Rate Base at Present Rates
June 30, 2014

Line No.	Acct. No.	Description	Pro forma May 31, 2012 (1) $	Adjustments (2) $	Pro Forma 31-May-13 (3) $	Adjustments (4) $	Pro Forma June 30, 2014 (5) $	Reference
1		**Property Plant and Equipment**						
2	101, 106	Gas Plant in Service	1,163,982,895	142,476,950	1,306,459,845	170,648,370	1,477,108,215	Exh 108, Schedule 1
3	107	Construction Work in Progress - In Service	2,637,017	(2,637,017)	0	0	0	Exh 108, Schedule 2
4	117/191	Gas Stored Underground - Non-Current	3,794,990	0	3,794,990	0	3,794,990	
5	108-111	Depreciation Reserve	(306,192,210)	(15,853,666)	(322,045,876) 1/	(18,906,230)	(340,952,106) 1/	Exh 108, Schedule 3
6	117	Accum. Provision Gas Lost - Underground Storage	(163,458)	0	(163,458)	0	(163,458)	Exhibit 1
7		Net Plant in Service	864,059,234	123,986,267	988,045,502	151,742,140	1,139,787,641	
8		**Working Capital**						
9	154-163-186	Materials and Supplies - 13 Month Average	642,733	(657)	642,076	20,939	663,015	Exh 108, Schedule 5
10	165	Prepayments	1,635,110	20,957	1,656,067	(4,139)	1,651,928	Exh 108, Schedule 6
11	164/242	Gas Storage Underground	84,406,062	(21,457,709)	62,948,353	11,577,794	74,526,147	Exh 108, Schedule 7
12		Cash Allowance	0	0	0	0	0	Exh 108, Schedule 4
13		Total Working Capital	86,683,905	(21,437,409)	65,246,496	11,594,594	76,841,090	
14		**Deferred Income Taxes**						
15	190	Income Taxes	17,716,119	(3,222,811)	14,493,308	(11,372,638)	3,120,670	Exh 108, Schedule 8
16	282	Depreciation	(165,114,508)	(34,091,455)	(199,205,963)	(21,537,259)	(220,743,222)	Exh 108, Schedule 8
17	283	Other	(161,800)	69,173	(92,627)	69,173	(23,454)	Exh 108, Schedule 8
18		Total Deferred Income Taxes	(147,560,189)	(37,245,093)	(184,805,282) 2/	(32,840,724)	(217,646,006) 2/	
19		**Customer Deposits**						
20	235	13 Month Average	(2,696,133)	21,283	(2,674,850)	3,563	(2,671,287)	Exh 108, Schedule 9
21		**Customer Advances for Construction**						
22	252	Cash Deposits	(155,517)	(61,980)	(217,497)	0	(217,497)	Exh 108, Schedule 10
23		**Total Rate Base**	800,331,300	65,263,069	865,594,369	130,499,573	996,093,941	

Notes:

1/ Per changes as outlined in witness Spano's testimony at Statement No. 5-R.

2/ Per changes as outlined in witness Fischer's testimony at Statement No. 11-R.

COLUMBIA STATEMENT NO. 106-SR

J-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
Columbia Gas of Pennsylvania, Inc.	)	

SURREBUTTAL TESTIMONY OF

NANCY J. D. KRAJOVIC

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

February 8, 2013

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Q. Please state your name and business address.

A. Nancy J. D. Krajovic, Southpointe Industrial Park, 121 Champion Way, Canonsburg, PA 15317

Q. Are you the same Nancy J. D. Krajovic that served direct and rebuttal testimony in this proceeding?

A. Yes.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the rebuttal testimony of witness James Crist, filed on behalf of the Natural Gas Suppliers ("NGS") regarding storage gas working capital (SGWC).

Q. In his rebuttal testimony Mr. Crist maintains that SGWC in the amount of $85,914,286 should be included in the GPC. Do you agree with Mr. Crist on the amount that represents the SGWC recovery in base rates?

A. No. Mr. Crist refers to the Company's Exhibit No. 8, Schedule No. 7 to calculate that amount. Exhibit No, 8, Schedule No. 7 represents historic monthly gas storage activity. Exhibit 108 Page 3 of 11 shows the Pro Forma Rate Base claim for the twelve months ended June 30, 2014 for Gas Stored Underground in the amount of $78,321,137 ($3,794,990 for non-current gas and $74,526,147 for current gas). A return on this amount appropriately represents base rate recovery of SGWC. This is the same SGWC to which OSBA witness Knecht referred in his testimony.

Q. Does Mr. Crist accurately describe the usage of CHOICE® suppliers' gas supplies in excess of CHOICE® customers' demand?

A. No. By the very nature of the average day program, the CHOICE® suppliers' monthly surplus or excess serves to annually balance their own weather normalized use of Columbia's storage gas. Therefore, CHOICE® customers are not supplying the sales services customers.

Q. Is the gas supplied by the CHOICE® suppliers distinguishable in the system?

A. No. Neither NGS deliveries, fluctuations for weather, nor system supply purchases are colored or streamed for or to specific purposes. As evidenced in my Exhibit NJDK-2R, on average in normal weather, NGSs under deliver .41 therms on a monthly basis. This imbalance is supported by storage or system supply. The Company meets all required injection and withdrawal constraints imposed regardless of the NGS imbalances, by compensating through purchases for storage or sales use. The inherent simplicity for the CHOICE® suppliers is one of the significant advantages of the Columbia's average day program.

Q. What is the purpose of the July 31st reconciliation of CHOICE® suppliers' gas banks?

A. The reconciliation at the end of the CHOICE® Program year serves to settle actual customer usage versus the weather normalized average day usage that determines the supply that the CHOICE® suppliers must deliver each day. It also reconciles the supplier deficit or banks for CHOICE® customers not signed up at the beginning of the Program year.

Q. Why is the CHOICE® Program reconciled in July?

A. As I described in my rebuttal testimony, gas deliveries are accounted for on a calendar month but customer usage and thus payments to suppliers are measured

based on a billing cycle. The annual reconciliation occurs at the end of July because there is little fluctuation in consumption between the months of July and August.

Q. Mr. Crist contends that suppliers actually start filling storage in April, which results in several months that the suppliers incur working capital costs. Please comment.

A. Under the program design, supplier deliveries in April are to payback the Company storage gas that suppliers used in prior months. In order to consider supplier deliveries in April to prospectively serve their customers' requirements the cash-out reconciliation would have to be shifted to March.

Q. Would changing the Program year to begin in April change the amount of gas that suppliers would be required to deliver under the average day program?

A. No.

Q. In his rebuttal testimony, Mr. Crist makes statements regarding Columbia's storage contracts. Does he offer any evidence to support his suppositions about the contracts?

A. No.

Q. Are there opportunities for the Company to earn profit from off-system sales made possible by the storage assets?

A. Yes.

Q. Is the Company's off-system sales program impacted by reconciliation in July versus April?

A. No.

Q. What is the disposition of those profits?

A. They are shared with customers under a Commission approved sharing plan via credits to the Company's Purchased Gas Demand Charge and the Purchased Gas Commodity Charge, with 75% of the profits being provided to the customers.

Q. Do CHOICE® customers pay either of those charges?

A. Yes. All of Columbia's customers pay the Purchased Gas Demand Charge and therefore share in the profits that are made from off-system sales.

Q. Mr. Crist suggests that if the Company is concerned that it is bearing costs unevenly it could modify the average day program and refers to the demand methodology utilized by other NGDCs. Has Columbia considered the demand methodology?

A. Yes. In the development of the CHOICE® program, Columbia did consider a demand curve model for determining supplier deliveries. However, due to the complexity with the number of pipelines providing delivery to Columbia, the widespread service territory, and the large number of delivery points, the average day program was selected as being the most appropriate.

Q. Does this conclude your testimony?

A. Yes.

COLUMBIA STATEMENT NO. 107-R

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

ROBERT M. KITCHELL

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. Robert M. Kitchell and my business address is 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

Q. Are you the same Robert M. Kitchell who submitted Direct Testimony in this Proceeding?

A. Yes, I am.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is twofold. First, I will respond to the testimony of the Office of Consumer Advocate's witness Thomas S. Catlin regarding Columbia's proposed incremental Operations and Maintenance ("O&M") expenses associated with pipeline safety initiatives that coincide with the Company's Distribution Integrity Management Program Plan ("DIMP Plan") initiatives, and second, I will respond to Mr. Catlin's same testimony wherein he addresses Columbia's new employee count.

Q. What do you wish to address regarding Mr. Catlin's testimony specific to Columbia's incremental O&M expense associated with pipeline integrity management and DIMP-related ("DIMP O&M") initiatives?

A. Mr. Catlin's testimony discusses Columbia's proposal to increase O&M by $7,570,000 to fund incremental pipeline integrity expenditures. Specifically, Columbia proposed the following incremental DIMP O&M expenditures:

- $900,000 Right of Way Clearing
- $900,000 Atmospheric Corrosion Remediation
- $1,350,000 Exposed Coated, CP Mains Maintenance

- $2,000,000 Repair of Type-2 leaks
- $900,000 Sewer Line Cross-Bore Remediation
- $1,170,000 MAOP Documentation
- $200,000 RP1162 Expenditures
- $150,000 Storage O&M Training

Mr. Catlin finds that Columbia did not separately track several of the above elements. Mr. Catlin also finds that where historical data is available, the incremental DIMP O&M expenditures reflect an increase over historical costs. In response to Mr. Catlin's findings he offers two recommendations: (1) that the incremental DIMP O&M expenditures be coordinated with Columbia's Long-Term Infrastructure Improvement Program, and (2), that Columbia track the expenditures for each of the incremental pipeline integrity management initiatives listed above and to what extend the goals of each element are met so that costs and accomplishments may be evaluated in the Company's next base rate proceeding.

Q. What is your response to Mr. Catlin's findings and recommendations?

A. Mr. Catlin is correct that Columbia does not have historical costs associated with some of the proposed pipeline integrity management initiatives. This is because many of these initiatives are specific incremental efforts that the Company is proposing in this case to enhance its system integrity. In response to Mr. Catlin's first recommendation, Columbia currently coordinates its overall integrity management efforts with its infrastructure replacement and DIMP Plan priorities and commits to continuing to do so. Columbia finds such coordination critical to

managing a safe and reliable system, and has articulated the importance of such close coordination in recent and currently pending matters before the Commission. *Natural Gas Pipeline and Performance Plans*, Docket No. M-2011-2271982 (Columbia Comments filed Dec. 5, 2011 and Jan. 13, 2012); *Petition of Columbia Gas of Pennsylvania, Inc. for Approval of Its Long Term Infrastructure Improvement Plan*, Docket No. P-2012-2338282 (filed on Dec. 7, 2012); *Petition of Columbia Gas of Pennsylvania, Inc. for Approval of a Distribution System Improvement Charge*, P-2012-2338282 (filed on Jan. 2, 2013).

In response to Mr. Catlin's second recommendation, Columbia agrees to track the incremental annual amounts spent on each specific pipeline integrity management initiative and to the extent specific goals are met.

Q. What do you wish to address regarding Mr. Catlin's testimony specific to Columbia's new employee count?

A. I am updating the staffing levels of the 55 positions described in my Direct Testimony to reflect that 49 positions have been filled. As I discussed in my Direct Testimony, Columbia anticipated it would need to fill more positions than were included in the claim in the case, and will continue doing so as needed. Of the four GIS Engineering Tech positions included in the Company's claim in this case, the Company has posted four, and filled two. I will note that we have not had successful candidates for the GPS Mapping Technician positions through our first round of screening, and the Company is changing this job title to Gas Operations Data & GIS Technician and has reposted this position. As compared

to the positions discussed on page 15 of my Direct Testimony, the following positions have been filled as of January 14, 2013:

Position	Included in claim	Incremental to claim	Filled
Construction Coordinators	14		14
Construction Specialists	4		4
Construction Operators	22		22
Field Engineers	3		3
GIS Engineering Techs	4	2	6 posted, 2 filled
Land Agents	3		3
Land Tech	1		1
System Planner	1		posted
GPS Mapping Techs	3		reposted

Q. Did the Company increase its claim in this case to include the two additional GIS Engineering Technician positions it has posted?

A. No, it has not. As I noted earlier, the Company anticipates a need for additional positions and will continue to fill those as needed.

Q. Does this conclude your rebuttal testimony?

A. Yes it does.

COLUMBIA STATEMENT NO. 108-R

J-13-13
Hbg 89

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

DANNY G. COTE

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. Danny G. Cote. My business address is 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

Q. Are you the same Danny G. Cote who submitted Direct Testimony in this Proceeding?

A. Yes I am.

Q. What is the purpose of your rebuttal testimony?

A. I am responding to the Bureau of Investigation and Enforcement's witness Andrew J. Geibel regarding the issues of pipeline replacement and customer-owned service lines. In addition, I am providing testimony in support of incremental plant additions. The Company has received an incremental allotment of $3.2 million for capital expenditures in the second half of 2013. These dollars are in addition to the capital budget as reflected in the Company's original filing. The Company was advised of this additional capital allocation after certain tax changes came into effect early this year.

PIPE REPLACEMENT

Q. What do you wish to address regarding Mr. Geibel's testimony on the topic of pipeline replacement?

A. Mr. Geibel's testimony addresses the Federal Distribution Integrity Management Program rule ("DIMP") improvements made to the Columbia System since 2006, Corrosion Replacement and Active Corrosion (including the Gas Safety Division's response and NC-30-07), and Customer Owned Services.

Q. Throughout his testimony Mr. Geibel refers repeatedly to an Operator's

responsibility under the Federal Distribution Integrity Management Program ("DIMP") rule, and makes the point that Columbia was only doing what was required of it under that rule. Do you agree with this code interpretation of the rule?

A. Yes, the now effective DIMP rule requires that an operator, like Columbia, use all available data to assess the distribution system carefully, identify and rank the risks found in the assessment, and then based on the hierarchy of risk; develop programs that will mitigate those risks over time. In addition, an operator is required to track the risk data over time to demonstrate the effectiveness of the programs developed to reduce the risks.

Q. So do you also agree with Mr. Geibel's conclusion regarding Columbia's performance that essentially states that everything Columbia did during that time was required by DIMP, and did not constitute any special effort or commitment on the Company's part? If not, why not?

A. No, I do not. Columbia actually began practicing the precepts of DIMP long before the DIMP rule went into effect on August 2, 2011. For example, in spite of the absence of the DIMP rule in 2007, a careful review of the trending data in Exhibit DGC-1R demonstrates that Columbia began to address the issues of:

- Third Party Damage Rates
- Open class 2 leakage Rates
- Instituting more frequent leakage surveys
- Eliminating inactive services
- Reducing its inventory of bare steel and cast iron.

Finally, Columbia would note that virtually every metric tracked in Exhibit DGC-1R has shown material improvement from the 2006\2007 highs (or lows) that existed when the Company began these initiatives through 2011\2012, all launched nearly five years prior to the enactment of the Federal DIMP rule.

Q. Was there any specific state or federal rule in place at that time that required the Company to take these actions in 2007?

A. No. There were general rules around addressing conditions on specific pipe segments (active corrosion, pipe that was determined to be unsafe, etc.) but nothing that required timely and structural pipe replacement programs, accelerated leakage surveys, systemic inactive service programs, targeted and measured programs to reduce third party damage rates. In my view, if these requirements had been in place at that time at the Federal or State level for distribution system operators, Pipeline and Hazardous Materials Safety Administration ("PHMSA") would not have needed to enact DIMP in 2011.

Q. In Mr. Geibel's testimony he discusses active corrosion, the Mt. Pleasant incident, NC-30-07, and CPA's response. Were you involved in these events and discussions? If so, do you have any comment?

A. Yes, Mr. Geibel is correct that Columbia recognized in 2006 and 2007 that it needed to address its first generation bare steel system, and that accelerating leak rates and the Mt. Pleasant incident certainly contributed to this evaluation. Having reached this conclusion, Columbia made a proposal to the Gas Safety Division which featured a 20 year bare steel replacement program to address the concerns expressed in NC-30-07 and its own evaluation of corrosion leak rates

and system performance trending.

Q. Did Gas Safety Staff and Columbia reach a written agreement on this proposal?

A. No. Columbia responded to the Gas Safety Division and NC-30-07 with a written settlement proposal that featured the items described on pages 9 and 10 of Mr. Geibel's testimony, committing to a 20 year replacement program. While Columbia and the Gas Safety Division discussed the proposal, it did not end up being memorialized in a settlement agreement. The lack of a SIGNED agreement notwithstanding, Columbia recognized that it needed to address the risks associated with its bare steel system, and so proceeded to implement the bare steel structural replacement program it offered in the proposed settlement agreement anyway.

CUSTOMER OWNED SERVICE LINES

Q. What do you wish to address regarding Mr. Geibel's testimony on the topic of customer owned service lines?

A. Mr. Geibel correctly notes both the safety and equity issues that are presented with customer owned services lines, and ultimately recommends that Columbia eliminate customer owned service lines due to both of these reasons. While the distinction between customer-owned service lines and company-owned service lines is addressed in the Company's tariff, I am advised by counsel that the origin of the issue resides in Pennsylvania statutory law, specifically Section 1510 of the Public Utility Code. Columbia historically has not owned service lines in Western Pennsylvania, and I am advised by counsel that Section 1510 prevents Columbia from taking ownership of these customer owned service lines. Indeed, Columbia

requested and received Commission permission to replace, but not take ownership or maintain, customer owned service lines in conjunction with its bare steel replacement program in a 2007 petition seeking a waiver of its tariff language. Replacement of customer-owned service lines is also a feature of the Company's 2012 Long Term Infrastructure Replacement Plan ("LTIIP"), which has been submitted to the Commission for review. Specifically, I would correct Mr. Geibel's reference to the number of service lines on page 14 of his testimony—the number Mr. Geibel cites is a reference to all service lines Columbia projects to replace—not just customer-owned service lines. As stated on page 13 of the Company's LTIIP, Columbia estimates that it will replace 7,000 to 9,000 service lines each year over the next five years for a total of 36,000 service lines. This estimate includes both customer and company owned service lines.

Although utility ownership of customer service lines as recommended by I&E would address this issue, I am advised by counsel that a tariff change alone will not provide the company with the authority it needs to take such ownership.

INCREMENTAL CAPITAL

Q. How does Columbia plan to spend the incremental $3.2 million in capital?

A. Columbia will spend this incremental capital on the replacement of bare steel and cast iron pipe consistent with the ongoing replacement activities described in my Direct Testimony in this proceeding.

Q. Does Columbia have enough capital projects lined up to install an additional $3.2 million dollars of replacement pipe in the second half of 2013?

A. Yes. The project planning process is ongoing, and Columbia uses Optimain (a main replacement prioritization assessment tool) to assess a large number of variables when determining what segments to replace in a given year. Some of these variables include: leak history, facility location, proximity to buildings, pressure, municipal or DOT construction, etc. Upon notification that Columbia was allotted an additional $3.2 million for mains replacement, the Company initiated the planning process, which will identify incremental segments for replacement, and ultimately, once the projects are designed, will be turned over to Columbia's construction department to execute.

Q. Does Columbia have sufficient construction resources available to increase its capital investment by $3.2 million?

A. Yes.

Q. Has Columbia included this incremental capital in its revised revenue requirement?

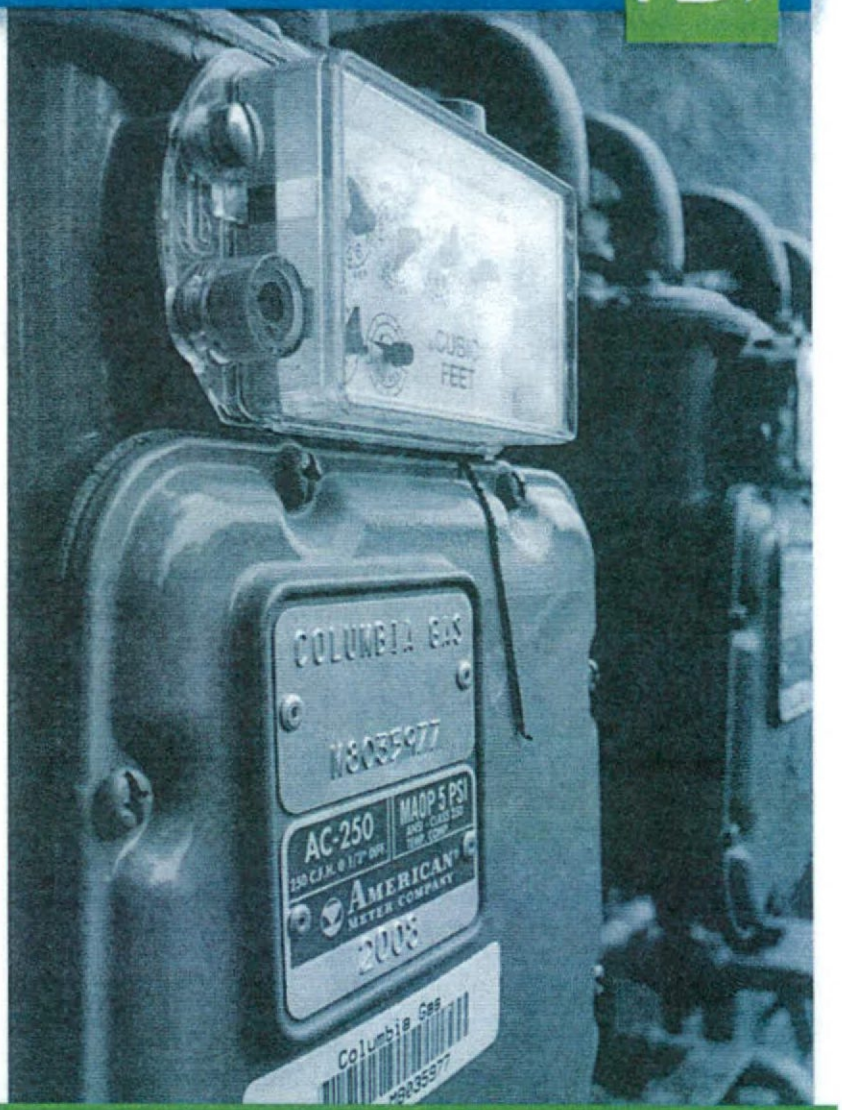
A. Yes. Company Witness Gore (Columbia Statement No. 104R) will explain the effect of the revised capital budget on the Company's claim in this case.

Q. Does this complete your Rebuttal Testimony?

A. Yes it does.

Columbia Gas® of Pennsylvania

A NiSource Company



CPA Historical Data

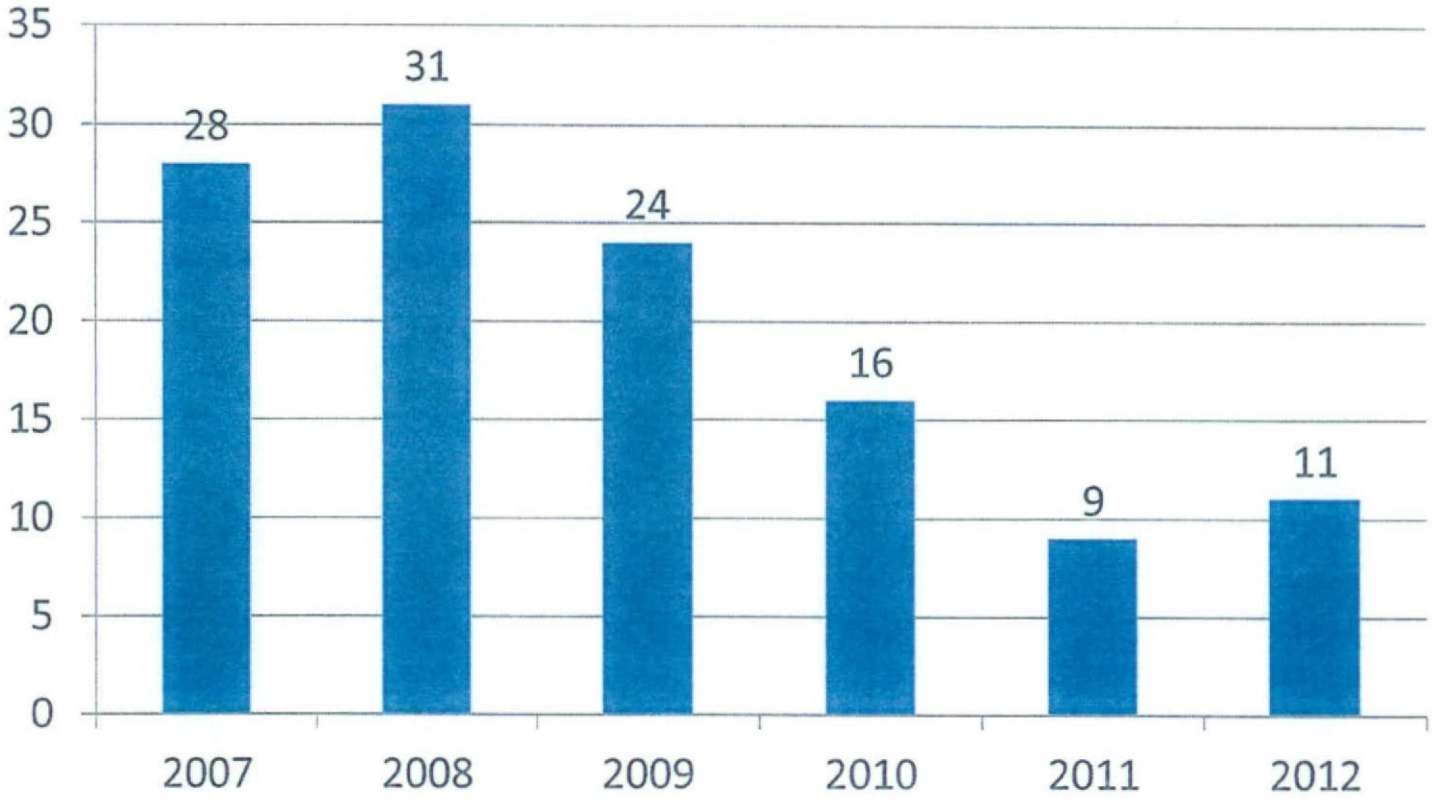
December 2012

CPA Profile

- 3rd Largest Gas Distribution LDC in Commonwealth
- ~ 414,679 Customers* in Portions of 26 Counties
- ~ 70 Bcf Annual Throughput / ~ 586 Mdth Peak Day
- ~ 478 Employees*
- 6 Interstate Pipelines with 325 PODs
- 7,325 Miles of Main with ~ 1,931 Miles of CIBS
- $66.3M OE Goal for 2011 and $130M Capital Program for 2011
- Residential Customer Charge Range: $8.55-$18.73
- Leader in CIBS Replacement
- Leader in Commission's Customer Service Reports
- CAP Program Considered "Statewide Model"

*Source: 2010 Annual Report

CPA OSHA Recordable Injuries

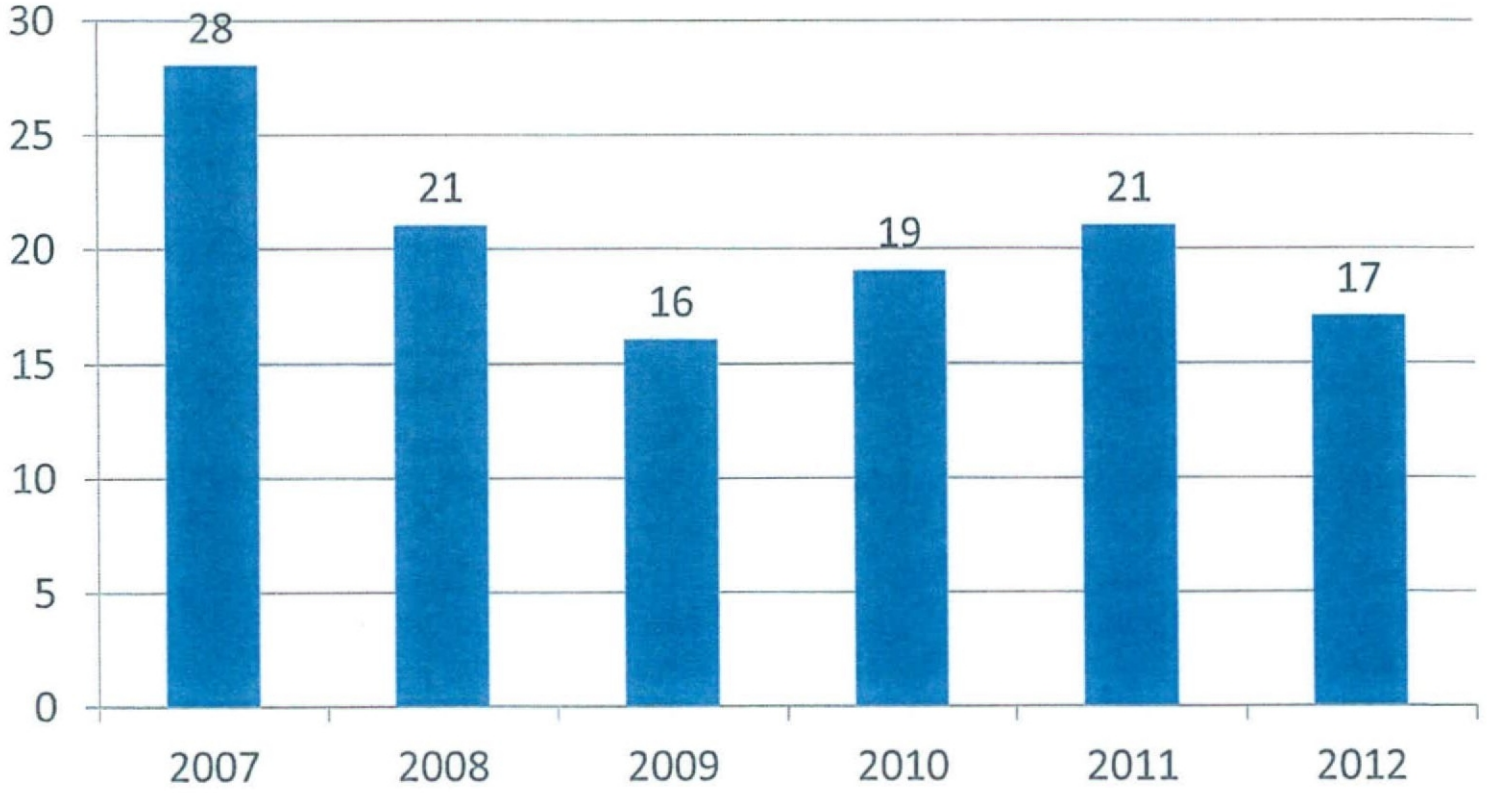


Columbia Gas of Pennsylvania
A NiSource Company

Columbia Gas of Maryland
A NiSource Company

A Reduction of More Than 66% Since 2007

CPA OSHA Preventable Vehicle Collisions

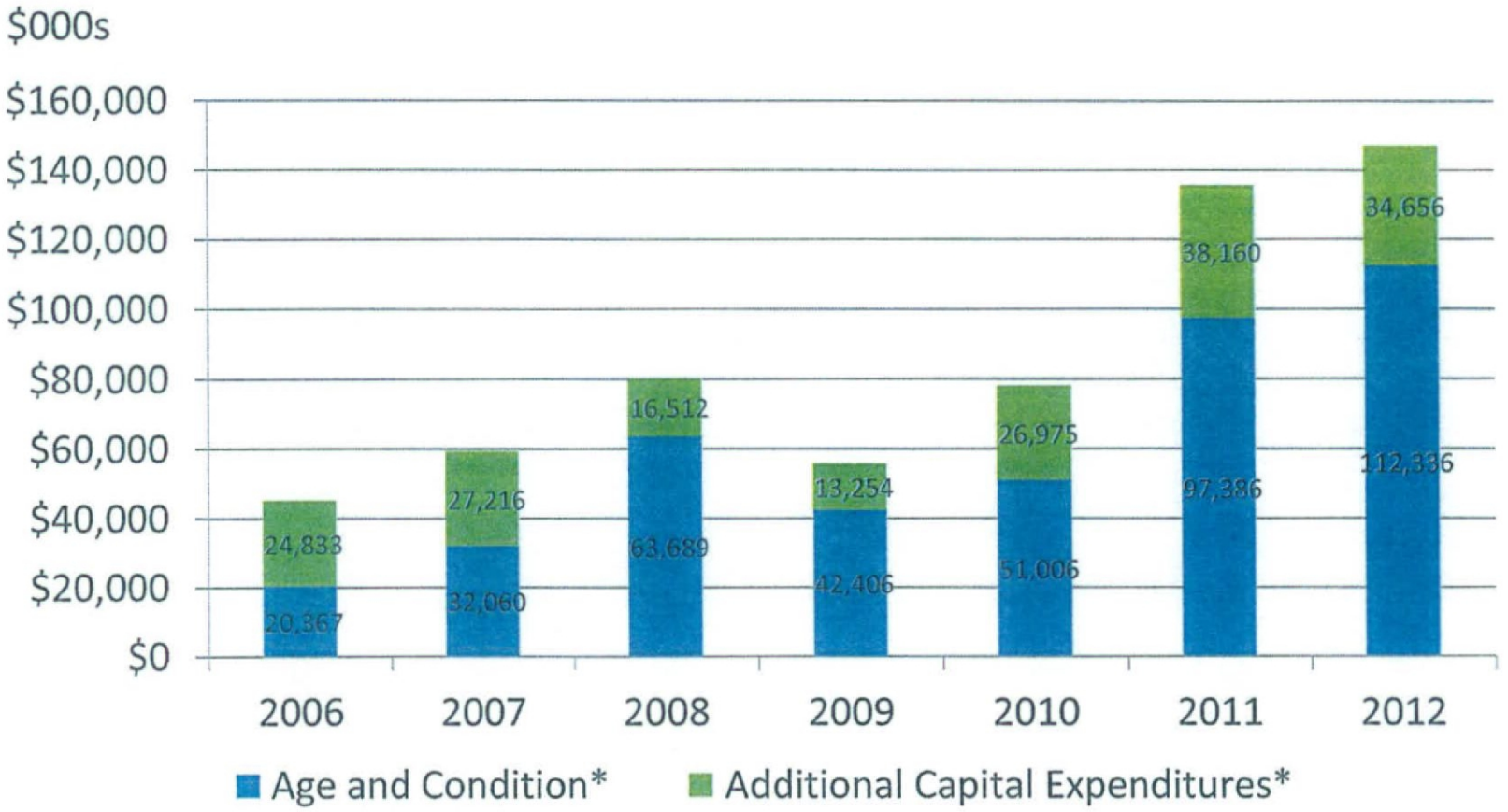


Columbia Gas of Pennsylvania
A NiSource Company

Columbia Gas of Maryland
A NiSource Company

Continued Improvement Priority

CPA Priority Pipe Program



Columbia Gas of Pennsylvania
A NiSource Company

Columbia Gas of Maryland
A NiSource Company

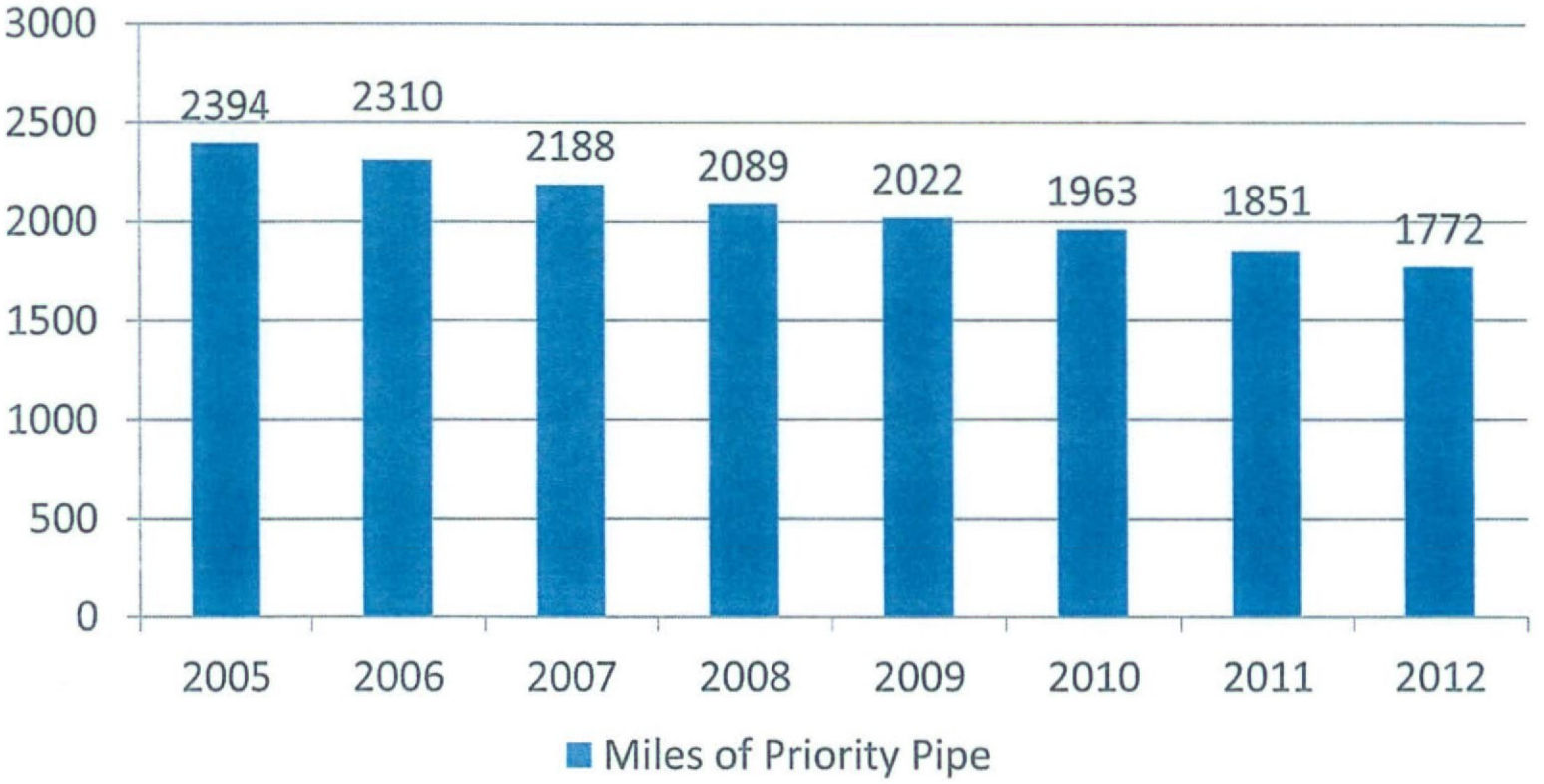
Age & Condition Budget Increased 350% 2006 to 2011

CPA Miles of Priority Pipe Retired

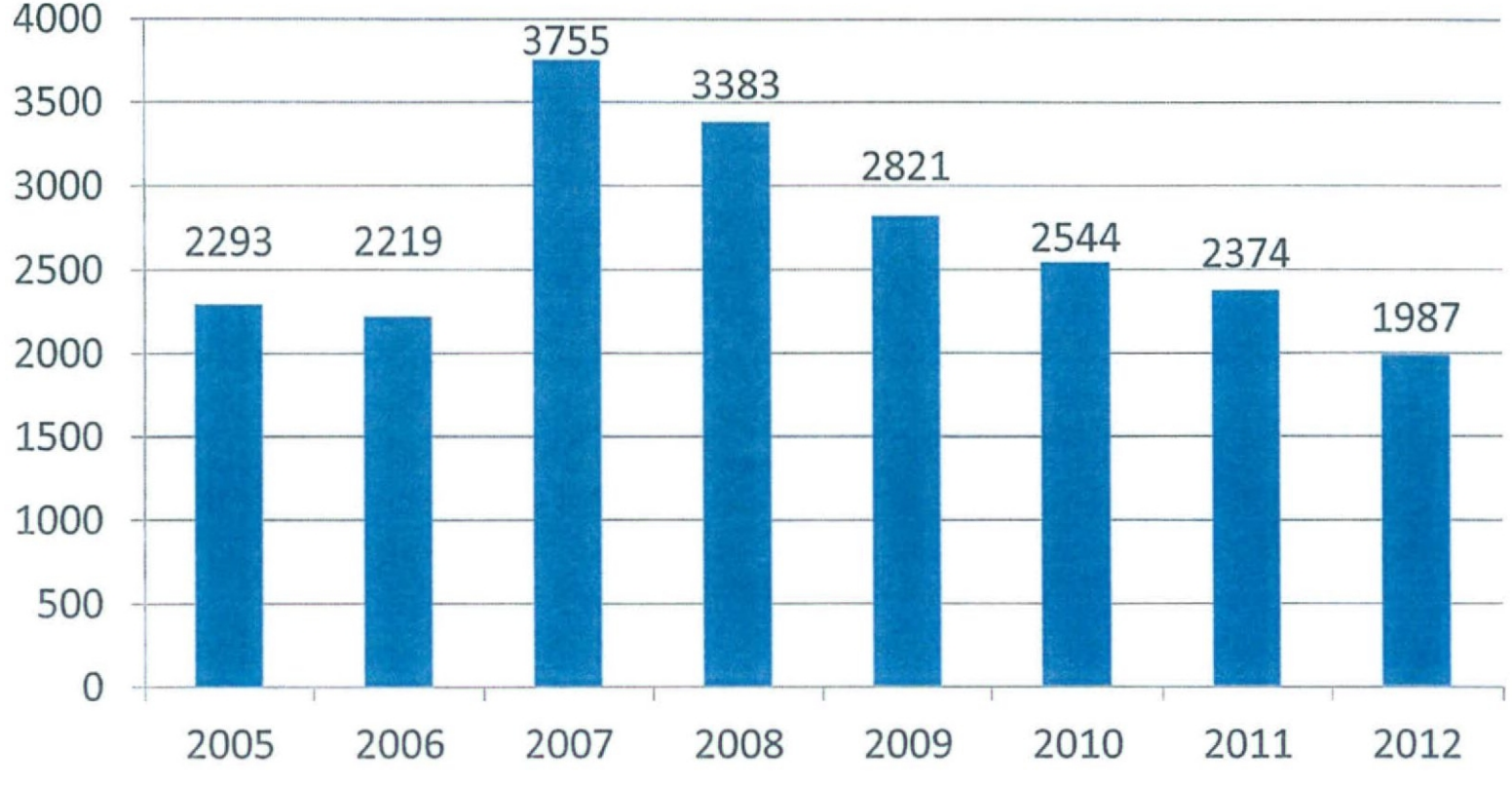


Retired More Than 20% of Priority Pipe Since 2006

CPA Remaining Priority Pipe

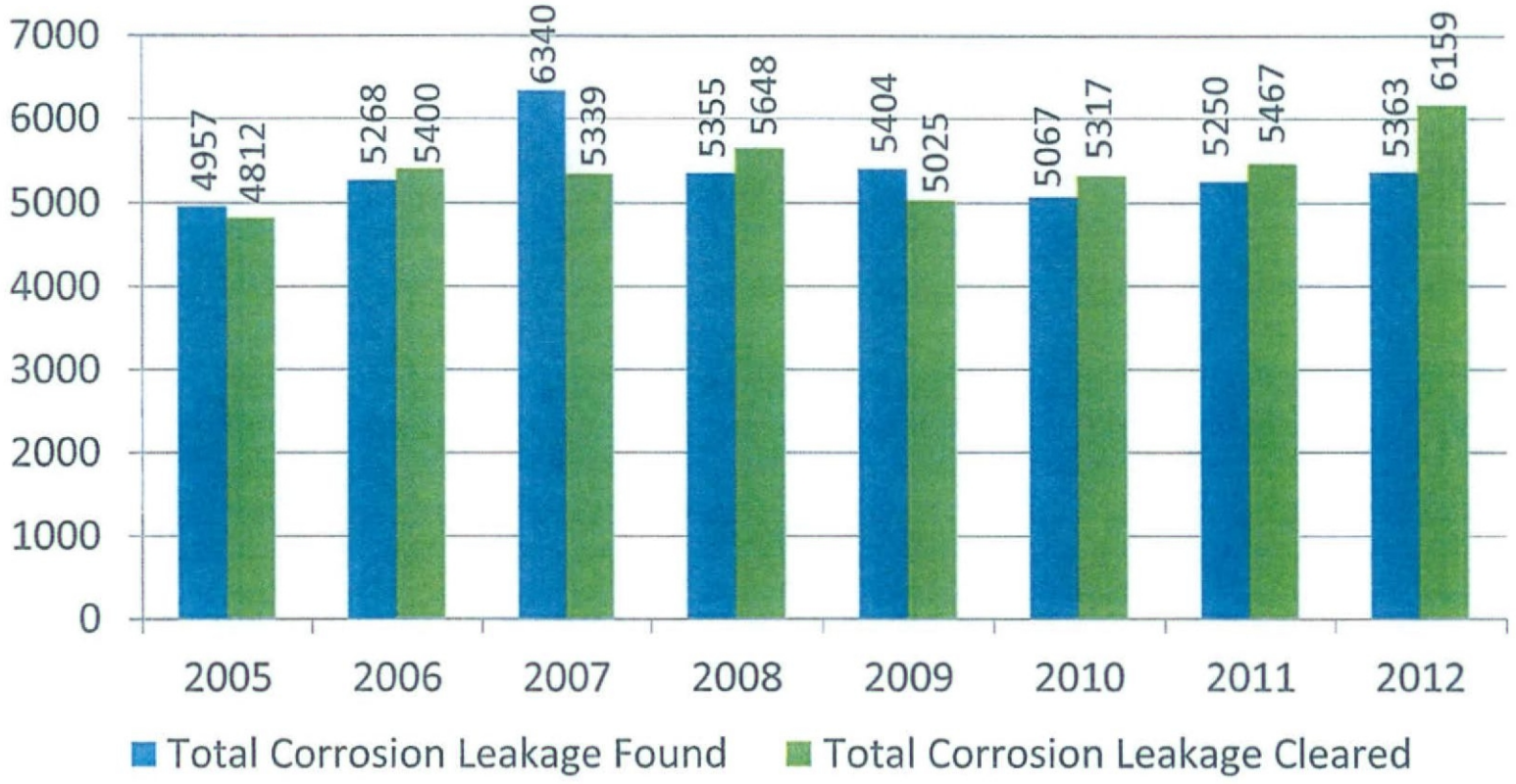


CPA Total Open Grade 2/2+ Leaks



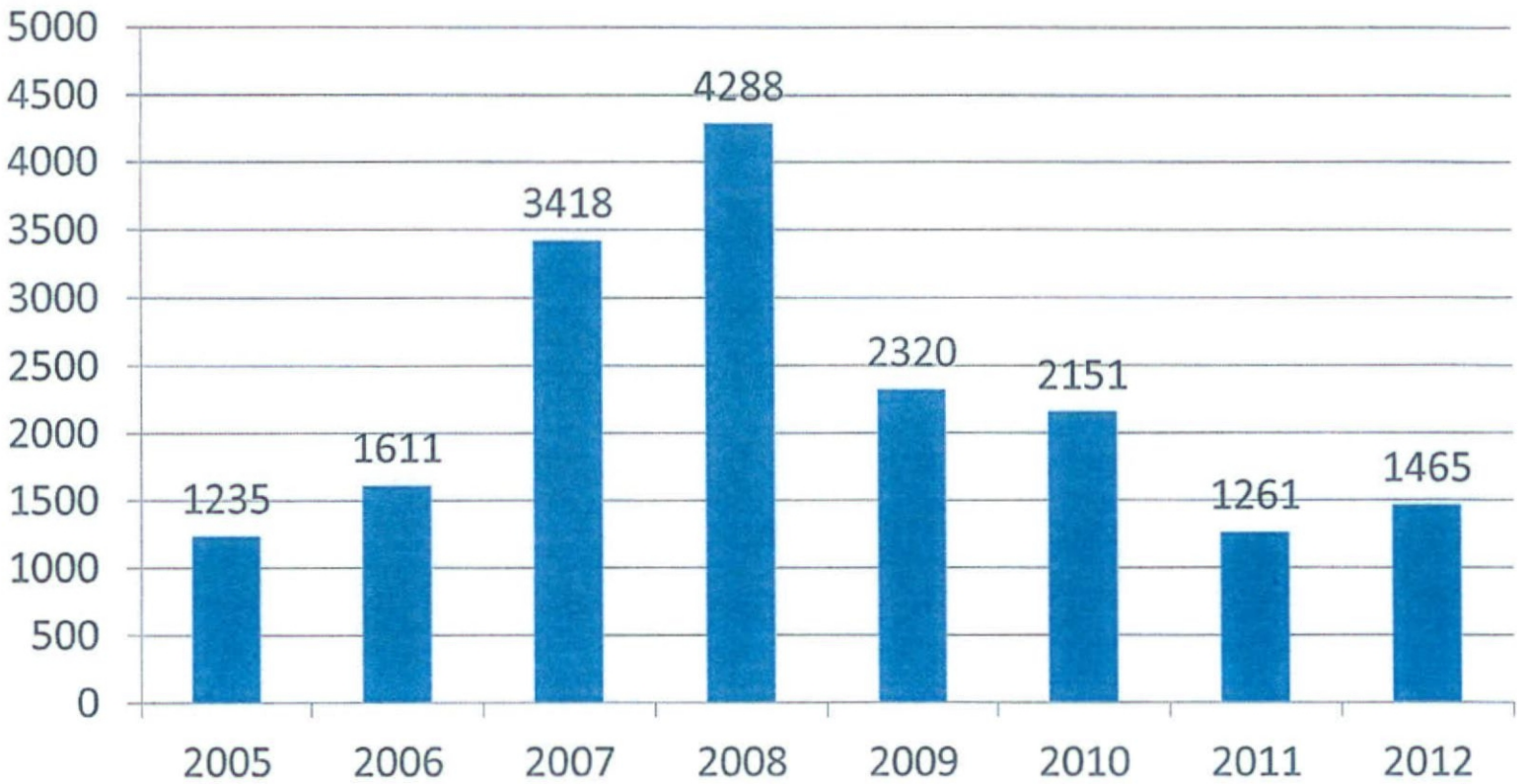
Leak Repair – Deliberate and by the Numbers

CPA Total Corrosion Leakage



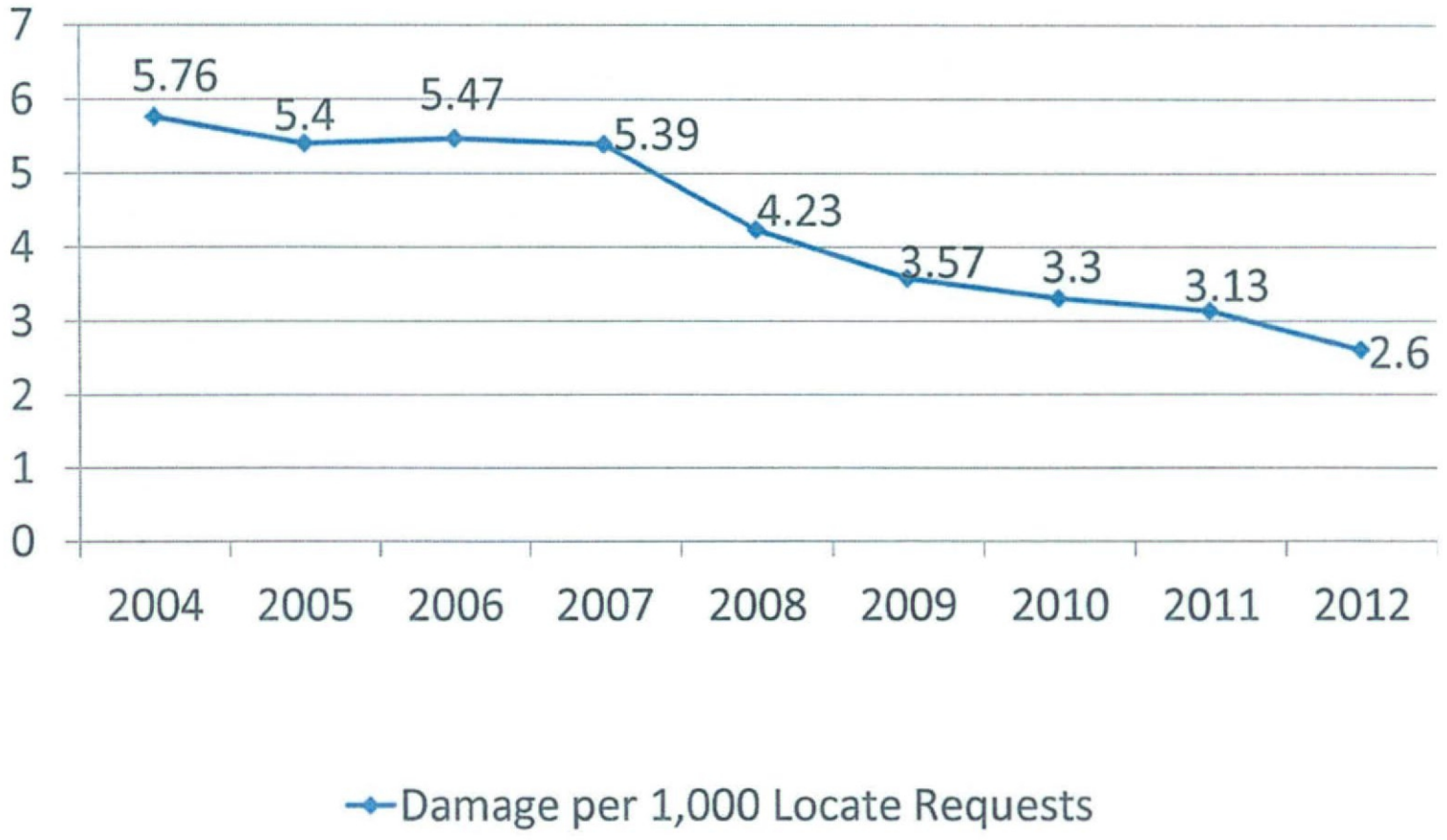
Corrosion Leakage Remains a CPA Challenge

CPA Service Abandonments



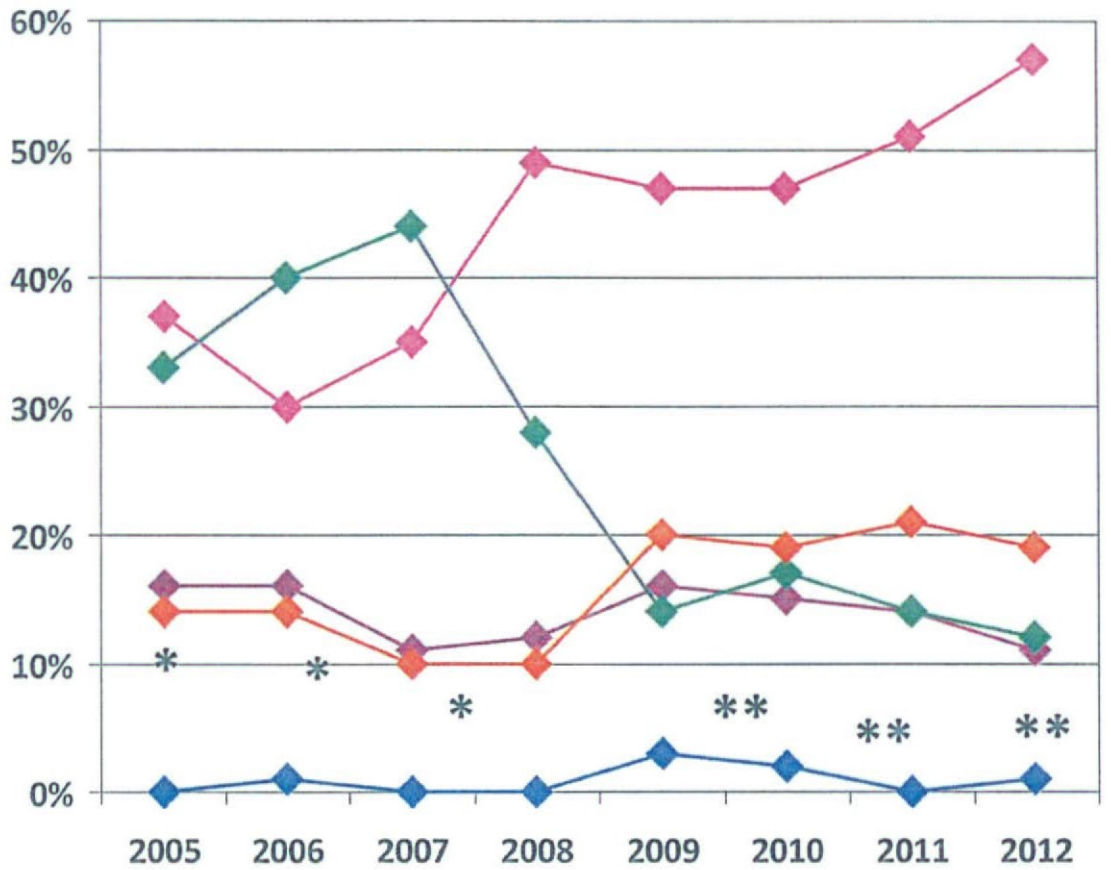
Blocking and Tackling for System Safety

CPA Facility Damages



Excavator Negligence #1 Cause of Damage

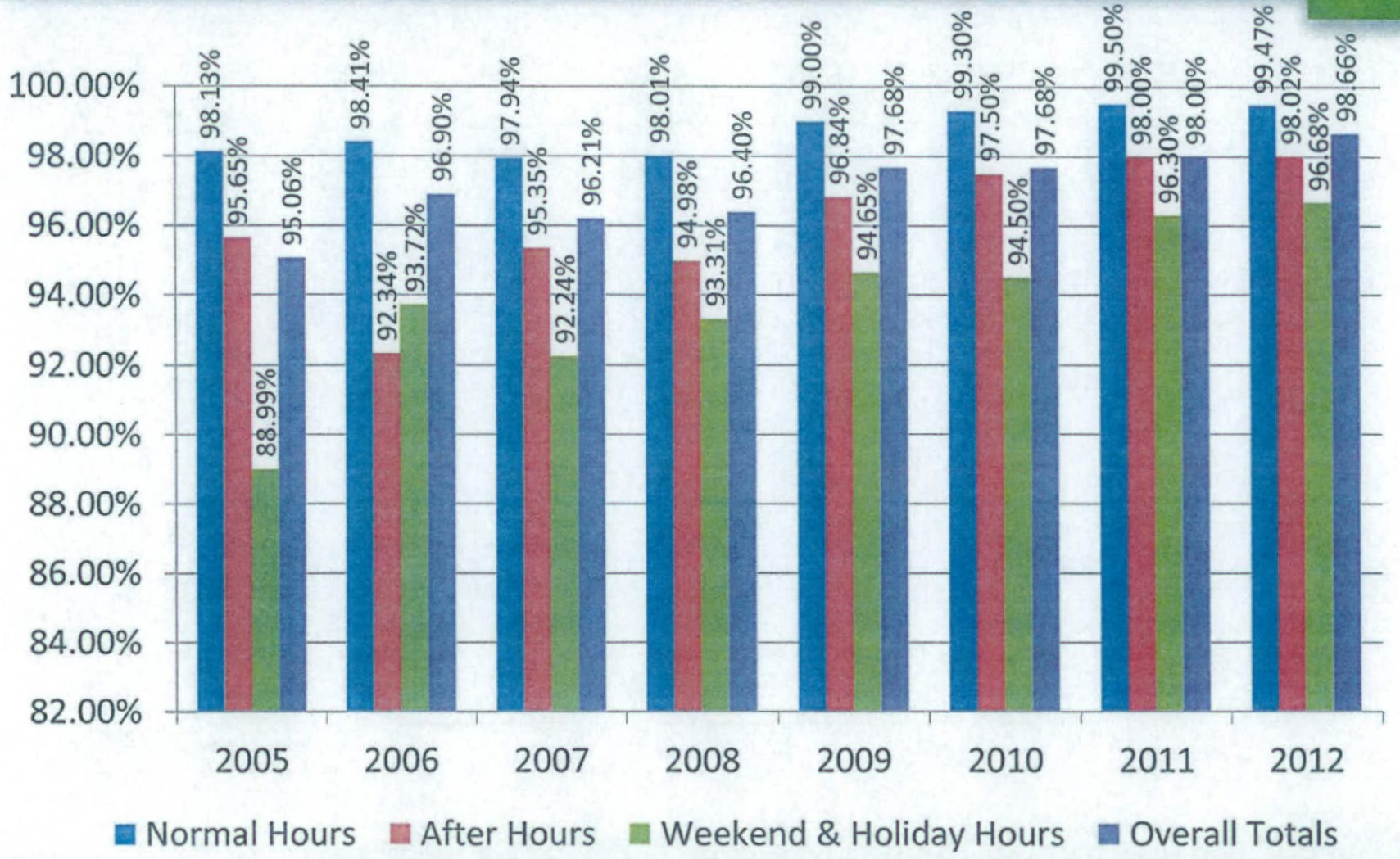
CPA Damages by Cause



* Poor Records captured in Other category.

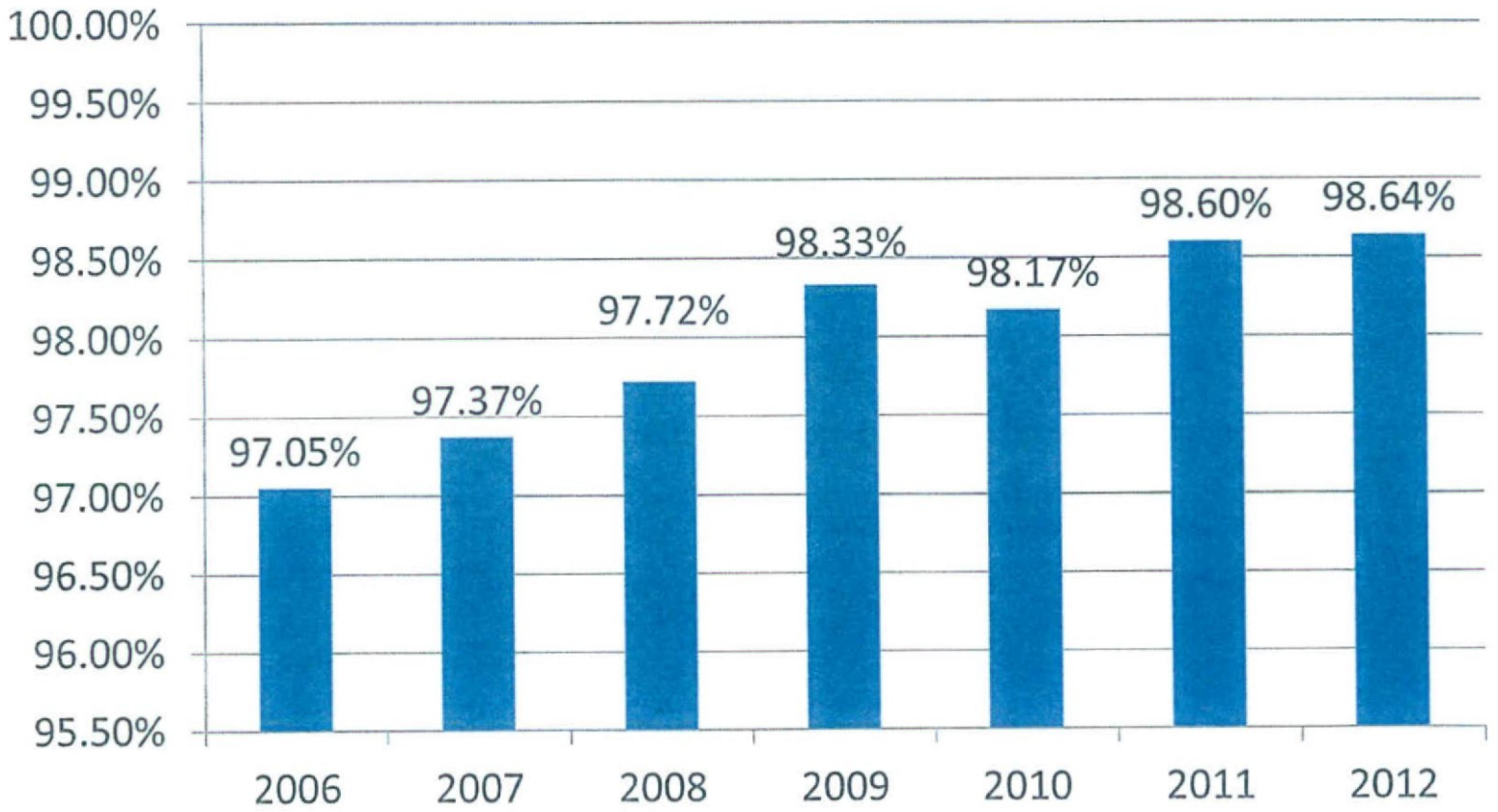
** Other Category is anything that did not fall into the four other categories.

CPA 1-Hour Emergency Response



Trend Line – Going in the Right Direction

CPA Service Appointments Met



Our Customers – Don't Forget Who Pays the Bill

Other Programs

- **DOT Reportable Incidents**
  - No DOT Reportable Incidents in 2012.
- **Atmospheric Corrosion**
  - Completed 4 years of a 6 year program - $500K per year.
  - Addressing exposed pipe on Bridges, Regulator Stations, Valve Nests and etc.
- **Critical Valve Initiative**
  - 2009-2013
  - 1,110 Critical Valves will be added to our system.
  - To date we have addressed 373 critical valves.
- **Meter Protection Pilot (York-2010)**
  - To date Leak Inspectors identified 1591 meter sets needing protection.
  - To date 1453 meters were protected.
- **In-sourcing Facility Locates**
  - All Pennsylvania areas now have insourced Facility Locators.

Other Programs (Cont'd)

- Electronic Markers
  - Started installation in 2010. Provides a secondary means of locating if tracer wire loses continuity and accurately indicates the location of certain pipeline features
- Excess Flow Valves
  - Installing on all services <5,000 cfh
- AMR
  - This project is complete.
  - 351,000 AMR devices were installed.

COLUMBIA STATEMENT NO. 109-R

2-13-13
Hbg R

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission ,	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

JOHN E. SKIRTICH

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. My name is John E. Skirtich and my business address is 279 Old Trail Dr. Columbus, Ohio OH 43213

Q. Are you the same John E. Skirtich that filed direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. I will be addressing positions taken by Mr. Knecht, witness for the Pennsylvania Office of Small Business Advocate, Mr. Watkins, witness for the Pennsylvania Office of Consumer Advocate ("OCA"), and Mr. Hubert, witness for the Bureau of Investigation and Enforcement ("I&E") of the Pennsylvania Public Utility Commission, regarding my Class Cost of Service Studies ("CCOSS") and/or ("studies"). I will also be addressing their positions on my System Charge calculation.

Q. Do you have any corrections and/or adjustments to your CCOSS as initially filed in this case.

A. Yes. During the period of investigation, several errors were identified related to information provided by the company plus linkage problems in my model that impact certain allocation factors. In addition I have accepted two changes suggested by Mr. Knecht in his testimony, rent revenue and uncollectibles, and corrected one allocation factor which I address later in my testimony. I have corrected the allocation factors and am submitting revised studies as Exhibits JES – 1R, Exhibit JES-2R, and Exhibit JES-3R for the Customer-Demand Study, the Peak and

Average Study, and the Average Study, respectively.

Q. Could you pleased describe the corrections you made to the studies?

A. The table below describes the allocation factor changes and notes the source of the changes.

Table JES-1

Allocation Factor	Description	Source of change
5 & 20 – Composite of 1 & 3 and Minimum System Mains	Overstatement of low pressure footage and linkage of mains investment	OSBA I -0011 & OCA V -007
15 - Services	Correction of duplicative service count in query	OSBA I -022
21 – Large Customer Relations	Inadvertent assignment of LDS customer counts to SDS	OSBA I -025
25 – Sales and CHOICE Transportation	Inadvertently excluded Rate SCD Volume from factor	OSBA I -012
1 – Design Day	Inadvertently assigned PPS Res. Design Day to SGS	OSBA Statement No. 1, Page 34.
7 & 23 – Distribution Uncollectibles and Unbundled Uncollectibles	Accepted Mr. Knecht allocation of uncollectibles	OSBA Statement No. 1, Pages 35 - 37

Q. Did you provide a comparison of the corrected allocation factors?

A. Yes. Exhibit JES-4R provides a comparison of the allocation factors as filed to the corrected ones. Exhibits JES-5R and 6R provide the support for the corrected Factors 5 and 20, respectively. Exhibits JES -5R and 6R also correct Exhibit JES-3,

Pages 5 and 6, respectively, as initially filed.

Q. How did the corrections impact the results of the studies?

A. Other than on LGS, the impact on the rates of return was inconsequential in relationship to the rates of return as initially filed. Exhibit JES-7R compares the rates of return for the three corrected studies to the returns for the three studies as initially filed. Because of the small number of customers under LGS, the correction of Allocation Factor 21, Large Customer Relations, positively impacted the rates of return for LGS by 4% to 7% at present and proposed rates under the three studies.

Q. How have these corrections affected the Revenue Change at System Average for LDS that you presented in Exhibit JES-5?

A. Since the rates of return were not significantly impacted by the corrections for LDS, the revenue change at the system average was small. Exhibit JES-8R compares the revenue change at the system average for LDS as corrected to the as filed amounts.

Q. Did you make any other changes to your studies?

A. The company provides support for minimum or system charges in its Customer Demand Study. The company submitted support under two different approaches; one incorporating a customer portion of mains, which the company uses in support of its system charges, and one without a customer component of mains.

As addressed in its response to OSBA I -019, the company agreed that "other rate base items" particularly accumulated deferred income taxes, customer advances and customer deposits should be included in the system charge calculations, The Company had not included these items previously. Exhibit JES-1R, pages 14

through 18 which contain the support for system charges has been revised to incorporate "other rate base items".

In addition, during my review of the system charge calculation under the customer component of mains approach (page 14), a linkage problem was discovered with Account 887, Mains, (Line 6) resulting in no mains expense being assigned to the calculation. The cell was relinked which added $5,276,224 to the customer component.

Exhibit JES-9R compares the system charges as revised and corrected to the levels initially filed in the case. Only the LGS rate schedule has a noticeable change in its system charge level.

Q. With these corrections and revisions, has the company changed or amended its position or underlying support related to its studies?

A. The company believes that the Customer Demand Study and the Peak & Average Study provide a reasonable range of returns for use as a guide in establishing appropriate rates. The corrections and revisions to the studies as initially filed had limited impact on the range and the Average Study.

Q. Did you provide the results of these corrected studies to Witness Strauss?

A. Yes. She has addressed how these studies impacted the Company's proposed rate design and revenue allocation in her rebuttal testimony.

CLASS COST OF SERVICE STUDIES

Q. Do you have any general comments regarding CCOSS as they related to

Pennsylvania remaking?

A. Yes. The Commission has consistently leaned toward CCOSS that reflect annual or average usage in allocating mains investment. It also has not in the past recognized a customer component of mains. The results of studies prepared in this manner generally over assign costs to the high load factor customers at the benefit of the smaller customers. As a result, rates for the larger customers exceed the cost to serve, which puts the utility at risk of bypass and fuel switching. These large customers are bypass threats because the cost to construct alternatives is much lower than what is derived from allocated cost of service studies, which over assigns costs, in setting rates. These customers can be served by large, dedicated facilities, and do not need to use all of the mains constructed to serve small use customers. This can be seen with customers served on Columbia's MDS rate schedule, where the customers are served by mains directly connected nearby interstate facilities. Furthermore, as I will explain later, these customers overwhelmingly do not use Columbia's small mains in receiving service from Columbia.

To respond to the ability of large customers to install lower cost alternatives to the Company's rate, that reflect allocation of mains costs in excess of the real cost to serve, utilities must flex rates to these customers to avoid losing them. If studies that recognized a customer component of mains, rely less on annual throughput, and reflect the large mains-small mains distinction, as reflected in the Company's studies, were given more weight in setting rates for the larger costumers, specifically the LDS rate class, then utilities rates would be more reflective of the

actual cost to serve such customers and the need to flex to avoid by-pass or fuel switching would be minimized.

Looking at the table below, the cost to serve LDS customers under the Company's Customer-Demand study is approximately $5.37 million. The average rate per DTH would be in the 30 cent range if set on the $5.37 million which is well below what Columbia is flexing on average at nearly 43 cents per DTH at current rates.

Table JES - 2

Item	LDS @ Current Rates		
	Customer /Demand Study	All Customers	Flex Customers
Cost to Serve	5,367,000	12,850,848	3,369,813
Total Volume DTH	17,788,342	17,788,342	7,989,927
Average Rate per DTH	$0.3017	$0.7224	$0.4281

Q. Is Columbia recommending that the Commission adopt the Customer-Demand type studies in setting rates?

A. As I stated in my direct testimony, the use of more than one cost allocation methodology allows for the recognition of judgment and gives the Commission a useful range of results. I believe the Commission should consider the use of a range of cost studies results in evaluating class cost of service as the Company has presented. If the Commission concludes that a single study should be used that

should be my Average study which reflects an average of the results of my Customer-Demand and Peak and Average studies.

Q. Please summarize the positions of OSBA, OCA and I&E regarding the Company's CCOSS.

A. Yes. The following summarizes their positions:

- OSBA – Mr. Knecht conducted two CCOSS studies; one using the Average and Excess method for allocating mains and mains related costs and a second one using the zero-intercept method to determine the customer company of mains with the remainder allocated based on demand. In addition, he excludes the small mains/large mains distinction in my cost studies. He compares the results of his studies to the Company's Customer-Demand Study and Peak and Average Study in Table IEc-7 of Mr. Knecht's testimony.
- OCA – Mr. Watkins conducted a CCOSS using a Peak and Average demand allocation method with no customer component of mains. He relies on the Company's Peak and Average study but adjusts Factor 5, which provides an equal weighting of design day and throughput for allocating mains and mains related costs, for the assignment of the 2" Pipe and Non 2" Low Pressure Pipe to RS/RDS and SGS/RDS customers.
- I&E – Mr. Hubert recommends the Commission rely on the Company's CCOSS that is based on allocating mains on the Peak and Average method with no customer component of mains.

Q. Do you agree with Mr. Knecht's discussion on the role or purpose and underlying

principles of CCOSS?

A. Yes I do. As Mr. Knecht explains, CCOSS are analytical tools with which the company's total cost of service or revenue requirement is assign to each rate class. They are used as a guide to establish the rates to charge each customer class with the ultimate goal to have rates set to recover the cost to serve each class. Further, the CCOSS can provide useful information for setting the customer charge, demand charge and commodity charge. Again as Mr. Knecht explains, the underlying principle in preparing the CCOSS is that costs are assigned to each rate class based on the class that causes the costs or more commonly used phrase costs are assigned based on cause causation.

Q. Is the biggest issue regarding CCOSS the classification and allocation of mains plant?

A. Yes. First, a gas utility's biggest investment is in mains. Columbia's mains investment in service at the end of the historic test year totals $603,233,938 or 60.2% of total utility plant in service. By the end of the fully forecasted test year, Columbia's mains investment is projected to grow to $911,044,198 or 61.7& of projected utility plant in service. The allocation of mains has a big impact on the level of rate base assigned to each customer plus the allocation of certain O&M costs are directly tied to mains investment such as accounts 874 and 887. Secondly, there are a number of acceptable or at least supportable methods to allocate the mains investment. As noted in my direct testimony, some favor the smaller size customers and some favor the larger customers. That is why Columbia has

historically filed multiple studies recognizing that there in not right study and that the two studies traditionally filed by Columbia provides a reasonable range of returns for use as a guide in establishing rates.

Q. Briefly describe the studies you prepared and filed in this case.

A. As in the past, a customer-demand study reflecting a customer component of mains based on a 2 inch minimum system and a peak and average study with no customer component of mains reflected were filed. In both studies, mains excluding mains directly assigned to the MLS/MDS class, were separated by the portion of mains that can only serve residential and SGS/SGDS customers ("smaller customer mains") and that portion of mains that can be used to serve all customers. The smaller customer mains were assigned to residential and SGS/SGDS customers with the remaining portion of mains assigned to all customers. The studies as noted above provide a reasonable range of rates of return. A third study was prepared averaging the two mains factors to provide a benchmark or guide that the parties and Commission can use as a guide in revenue allocation.

Q. Did Mr. Knecht agree with the assignment of the smaller customer mains to just the residential and SGS/SDGS customers?

A. Mr. Knecht noted that the approach has cost causation logic, but he rejects the approach noting that it is based on the underlying assumption that all customers are served by all of the large diameter high pressure mains, and only smaller customers are served by the small diameter low pressure mains. Thus, if the smaller mains serve only small customers, and the larger mains proportionately serve all

rates, the company's approach would be reasonable. He rejects the Company's method saying we did not demonstrate that the company's gas system in fact operates precisely in line with the allocation procedure for large customers. Further, Mr. Knecht lists some flaws which he claims overstates costs to smaller customers.

Q. Do you agree with Mr. Knecht's arguments?

A. No. I believe the identification and assignment of the small customer mains to residential and SGS/SGDS customers is consistent with cost causation principles and appropriate. We know that Columbia's large customers' requirements cannot be served from a low pressure system. Further, it was confirmed via a computer program that no LDS and only 19 LGS and 36 SDS accounts[1] out of 79 and 416_ accounts, respectively, rely on either a 2-inch or low pressure main. It appears these few customers are customers with multiple meters with combined usage that brings them within these intermediate size rate classes. Based on initial estimates, the impacts on the rates of return under the Customer-Demand study if the LGS and SDS classes were allocated small mains in proportion to the number of customers served are negligible and range from less than 1.5% on SDS to less than a .1% on RS/RDS and SGS/SGDS for the Peak and Average study. It is completely inconsistent with cost causation principles to assign small mains investment to these rate classes in the manner adopted by Mr. Knecht. The flaws claimed by Mr. Knecht in Columbia's approach are mere refinements that would enhance cost

[1] In response to OSBA I -011, 21 LGS and 38 SDS accounts were reported. It was later discovered that 2 LGS and 2 SDS accounts were actually company facilities such as exchange stations.

causation, but are in no way a reason to revert to a method that assigns costs to customers that do not create the cost. In that regard, I note that Mr. Knecht observed in his direct testimony that it is preferable to use a reasonable approximation in allocating costs than to adopt a methodology that is incorrect.

Q. Did Mr. Knecht try to further refine the assignment of mains to classes?

A. No. Mr. Knecht turned to the more traditional approaches to the assignment of mains that he has supported in previous cases. He filed two studies; one containing a customer component of mains using the zero-intercept method and assigning the remainder on demand and a second using the average and excess method.

Q. Did Mr. Knecht note any other issues regarding your studies?

A. Mr. Knecht addressed issues regarding a few items incorporating a couple of changes which I will address individually:

- **Meter costs;** Mr. Knecht recognizes that the company's approach to assigning meter costs is not unreasonable, however, he notes that the average costs of the various size meters are not intuitive. In addition, Mr. Knecht argues that the assignment of the various size meters to the rate classes is also not intuitive with the larger rate classes being assigned a number of small meters. The average costs are based on the company's plant accounting records, and age of the meters has a direct impact on the average costs which could cause some disparity. As he notes, some large accounts may have multiple premises with small meter settings which are combined for billing such as a hospital or college campus. The Company's approach of identifying the size meter for each class and applying the average

cost for each size meter is a reasonable method in assigning meter costs.

- **Services costs;** the service cost factor, No. 15, is based on the average cost of services under 3" and 3" and larger applied to the number of services by size in each rate class. Mr. Knecht argues that this approach assumes that the service line cost for each of the larger customers is the same as that of a residential or small business. Averages do over and/or under assign as a customer or group of customers costs are different from the average. However, when missing needed information and when lacking a basis for a reasoned modification, averaging techniques are acceptable. Further, the cost of some larger customers that have combined accounts could have the same service line costs as a residential customer.
- **Design Day;** Mr. Knecht makes two adjustments to the Company's design day level. The first adjustment revises the SDS and LDS design day amounts to reflect their peak day demands for SDS and LDS recognizing that the distribution system must generally be sized to meet the demand for the customer's peak day rather than on the system peak day. He also shifted some NSS design day from SGS/SGDS to MDS referencing the response to OSBA I – 12 (b). Regarding Mr. Knecht's moving to more of a non-coincident peak day approach, it is another method as he even notes that there are several accepted methods. Columbia has always used the company's design day to develop its CCOSS. On the second adjustment Mr. Knecht identifies correctly that residential PPS design day volume were assigned to SGS/SGDS, however, he

moves design day volume for NSS demand to MDS based on the response provided to OSBA-I-012. The response to OSBA –I-012 (b) explains that certain SGS/SGDS customers were taking firm service under Columbia's Negotiated Sale Service ("NSS") at the time of developing the forecast. Their design day volume was assigned to SGS/SGDS in developing the forecast. These customers are no longer contracting for NSS but are taking firm service, which Columbia has the commitment, under SGS/SGDS. These are not MLS/MDS customers and are properly included under SGS/SGDS.

- **Industrial metering and regulating ("M&R") equipment cost allocation;** Columbia developed, as in the past, its M&R factor based on M&R stations assigned to the various rate classes from its Distribution Information System ("DIS") and applying the average cost developed from its plant accounting records. Mr. Knecht noted that this approach may over and/or under assign costs to the rate schedules as they differ from the average. He calculated, based on the cost per station of Non-MDS and MDS customers, a linear relationship between the unit costs and average size customer. He applied this relationship to derive an alternative allocation factor. I agree with Mr. Knecht that using averages may somewhat impact customer classes unfairly. However, as Mr. Knecht states, his alternative approach has only a relatively modest impact on the allocation of the cost, therefore, I see no reason to change the approach the company has consistently used in preparing its CCOSS.
- **Uncollectibles;**. After reviewing the Company's new write-off reports and

aging reports, it is apparent that the residential customer class creates the substantial portion of the Company's uncollectibles. The DIS revenue factor overstates the assignment of distribution and demand gas cost write-off to the other classes. Due to the lack of rate schedule information by the Company, I've elected to accept Mr. Knecht's allocation. To incorporate his allocation of uncollectibles expense, I have changed Factor 7 and Factor 23 with Factor 23 now titled Distribution Uncollectible and allocating uncollectible excluding Direct USP Uncollectibles and Uncollectibles-Unbundled Gas. The Direct USP Uncollectibles are directly assigned to RS/RDS and the Uncollectibles-Unbundled Gas allocated to RS/GS and SGS/SGDS on the new percentages. The amounts assigned to each rate class match in total the amounts shown in Mr. Knecht's CCOSS, IEcZI Coss and IEc A&E Coss, as provided to the Company in response to the company's data request.

- **Storage gas working capital allocation;** Mr. Knecht notes that storage working capital should be allocated based on excess winter volume over summer which more accurately reflect cost causation. But since the Commission precedent has been to allocate storage costs on a volumetric basis, as the Company has, he accepts the approach.
- **Rent revenues;** the rental income is for company facilities. The allocation assignment was changed to general plant for the revised studies.
- **Large customer relations costs;** a number of SDS customers were assigned to rate class LGS in developing Factor 21 for Columbia's initial filing. The correct

number of customers is reflected in Columbia's revised studies.

- **Sale plus CHOICE allocation factor;** transportation volume for rate class SCD was inadvertently excluded in developing Factor 25. The revised studies reflect the correction.

Q. How do Mr. Knecht's results compare to Columbia's?

A. Mr. Knecht compares the filed for RORs to his in Table IEc-7. As he comments, his studies present results very similar to the Company's for the classes except for SDS and LDS. The principal reason for the difference appears to be due to his failure to reflect the distinction in allocation between small mains and large mains.

Q. What comments do you have regarding Mr. Watkins' CCOSS?

A. Mr. Watkins relies on the Peak and Average methodology stating in his opinion that it more reasonably assigns cost responsibility to customer classes. He adjusted the Company's Peak and Average study for two items. He eliminated the assignment of the small customer mains to RS/RDS and SGS/SGDS and updated Factor 25 to include volumes related to SCD which were omitted by the Company, but he also included volume related to SGDS with no explanation.

Q. Do you agree with these changes?

A. I agree with adjusting Factor 25 for the SCD volume as I explained earlier that it was a linkage error. I do not agree with the eliminations of the assignment of the small customer mains to RS/RDS and SGS/SGDS. As I addressed earlier, without the small customer mains assignment, the cost to serve the larger customers will be overstated. Mr. Watkins has accepted the direct assignment of mains and other

plant to the MLS/MDS class. The assignment of the small customer mains is consistent with the direct assignment to MLS/MDS based on the cost to serve those customers, therefore, the assignment of the small customer mains is also consistent with cause-causation principles as I mentioned earlier.

Q. Mr. Walkins disagrees with your Customer-Demand study because it doesn't consider annual usage. Do you agree with his arguments?

A. Mr. Watkins states that customers connect to the system to meet their natural gas needs throughout the year. The mains are utilized each and every day of the year so annual throughput is a logical basis for cost assignment. It is generally true, in my opinion, that most customers expect service 365 days a year. But, residential customers take gas because of the advantages, in terms of cost and warmth, it provides during the winter as indicated by the fact that Columbia has a 98% heating saturation for residential customers which implies more of a peak approach versus an annual throughput approach. Furthermore, annual throughput is not a basis for costs. For the larger customers, the customer's peak hourly demand is critical in ensuring the correct facilities are installed.

He also states that the customer-demand study assumes an optimally designed and installed system to meet today's mix and level of customers which is not true. All COSS have certain assumptions in them, but we are not assuming an optimal system but are reflecting the fact that large customers are not served

by small mains and small customers either are served by large mains or are served by small mains generally fed from large mains.

Q. Do you have any comments regarding Mr. Hubert's position?

A. Mr. Hubert relies on the Commission using the Peak and Average method to allocate the revenue increase. However, from my experience the Commission has recognized that there is no one correct study in determining the cost to serve a customer group. The Company believes that the Commission should look at all the CCOSS in determining revenue allocation.

Q. Could you please explain what the impact would be if the company lost NGDC bypass customers?

A. In the short term, the company would lose the revenue preventing or at least reducing the company's opportunity to earn its fair rate of return. In the next rate case, when CCOSS are prepared, the costs will be shifted to all other customers since virtually all the costs are fixed and could not be shed. Allocation factors will change based on the new data which will be absent of the NGDC amounts. This will increase the percentages to the smaller customers shifting costs and requiring more revenue to be provided by the smaller customers. The fixed cost recovery provided by the NGDC customers will be lost and picked up by the smaller customers.

Q. Could you summarize your position on CCOSS?

A. As stated in my direct testimony, Columbia recognizes that no one cost of service study is the "right" study in calculating the true cost to serve each customer class,

and believes that two such studies provides a reasonable range of returns to be used as a guide to establishing rate. However, the Commission has historically leaned to the cost of service studies that rely more heavily on annual or average throughput (Peak and Average and Average Excess). This results in pushing a substantial amount of costs to the larger, competitive customers forcing utilities to flex its rates for such customers or risk losing them to alternate fuel at no one's long term benefit. The Commission needs to recognize in setting rates that the cost to serve the large customers is in no way close to what is reflected in the throughput studies. The commission needs to consider the range of results in evaluating the class cost responsibility in setting rates.

SYSTEM ("CUSTOMER") CHARGE ANALYSIS

Q. Do you have any organizational/clarifying features related to this topic in your rebuttal testimony?

A. The Company proposed to change its Customer Charge designation to System Charge. The "as filed" supporting analysis included in Exhibit No. 111, Schedule 1 displays it as System Charge. However, the witnesses referred to it in their supporting analysis and testimony as Customer Charge. To avoid confusion when comparing the supporting analyses, I will be using the term Customer Charge.

Q. Do you have any comments regarding Mr. Hubert's customer charge analysis?

A. Mr. Hubert states that the customer charge should include only those direct

customer costs which increases each time a new customer is added or decreases when a customer is lost.

Q. What items did Mr. Hubert include in his analysis?

A. He presents his customer charge analysis in his Exhibit No. 3, Schedule 9. The analysis includes meter and regulator expenses, expenses for services and customer installations, meter and regulator maintenance expenses, expenses for meter reading and customer records & collections, customer assistance expense, depreciation expense and net salvage amortized for meters, services regulators, meters installations, and industrial measure and regulating equipment, and the rate base related return and income taxes on customer-based rate base.

Q. Did Mr. Hubert include any indirect costs related to these direct costs?

A. No. Mr. Hubert excluded both indirect benefits and other A&G costs related to these direct costs.

Q. What was the basis for Mr. Hubert including just the direct costs?

A. Mr. Hubert stated that the Commission affirmed its long-standing principle that only direct customer costs should be recovered in a customer charge in Columbia's last rate case at Docket No. R-2010-2215623 with the adoption of the I&E recommendation to limit the determination of the customer charge to those direct cost items.

Q. Has the Commission recently included indirect customer and other costs in approving customer charge levels?

A. As I understand it, the Commission, in the PPL Electric Utilities Corporation

("PPL") general rate case at Docket No. R-2012-2290597, concluded that the Administrative Law Judges' ("ALJ") correctly recommended that other customer-related costs are properly includable in a customer charge analysis. The other costs included PPL's Meter Data System, employee benefits and Administrative and General, and other O&M expense related to the direct costs. The ALJ relied on the Commission's Order in the Aqua Pennsylvania, Inc. case at Docket No. R-00038805. Based on these cases, Mr. Hubert should have included at a minimum similar type costs. The Company's Cost Analysis excluding a customer component of mains presented in Exhibit No. 111, Schedule 1, Pages 17 and 18 identified such costs.

Q. How did Mr. Watkins calculate his Residential Customer Charge Analysis?

A. As with Mr. Hubert, Mr. Watkins presented a traditional direct Customer Charge Analysis reflecting net plant related to Services, Meters, Automatic Meter Reading Devices, House Regulators and House Regulator Installations. In addition he included related depreciation and direct Operating and Maintenance expenses to these plant accounts and direct Meter Reading costs, Billing and Accounting costs, and Rendering Bills costs. He did not include any indirect benefits and other A&G costs. He showed two calculations; one using the proposed rate of return by the company and one at the rate of return as recommended by OCA witness Kahal. His results are shown on Schedule GAW-4.

Q. What comments do you have regarding Mr. Watkins' analysis?

A. Based on the latest Commission order on customer costs, as discussed above, he

has omitted employee benefits and other A&G expenses related to the direct costs he included. Also, I noticed that he did not include any operating costs for service included in FERC account 874, Mains and Services. This account included operating costs related to both Mains and Services and some portion of this account related to services should be included in the analysis. Not to include the cost understates the customer costs.

Q. Do you have any comments regarding Mr. Knecht's customer charge position?

A. Mr. Knecht has traditionally reflected a customer component of mains in his analysis which the company concurs.

Q. Do you agree with Mr. Knecht that it should be recognized that the customer costs assigned to smaller SGSS/SGDS customer costs should be exactly the same as the customer cost assigned to the typical residential customer?

A. This is more a rate design issue. In discussing with the Engineering and the New Business departments whether the smaller SGS/SGD initial new customer investment is relatively the same for a typical new residential customer, they indicated they could be close. But just looking at meters, the residential customer meter size is typically an AC250, which costs between $100 and $250 installed. While it is true that a small commercial customer may also require an AC 250 meter, at the top of the first tier, which is annual usage of 6438 therms, of the SGS/SDS rate class, commercial customers would require a larger meter size, an AL 425, which costs between $250 and $400. So the costs are not identical. However, Ms. Strauss needs to address if is acceptable to set the smaller

customer charge level at the residential level and the larger customers set at a level to ensure it gives the Company a reasonable opportunity to recover the class' customer-related cost.

Q. Please summarize your rebuttal testimony related to customer costs?

A. The customer cost analyses prepared by Mr. Hubert and Mr. Watkins are significantly deficient. Based on the Commission's order in the PPL case, Mr. Hubert and Mr. Watkins should have included, at the least, indirect benefits and other O&M and A&G expenses related to the direct cost. The Commission should reject both of these studies and rely on the Company's analysis inclusive of a customer component of mains which fully supports all customer related costs.

Q. Does this complete your rebuttal testimony?

A. Yes.

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - PROFORMA @ PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 1 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
1	TOTAL REVENUE [PAGE 6]		456,618,492	336,141,012	89,814,318	6,171,022	10,113,990	12,874,610	1,503,541
2	PRODUCTS PURCHASED [PAGE 7]		149,947,002	108,320,476	37,601,396	4,025,130	-	-	251,625
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		138,880,661	116,274,253	17,810,538	428,364	1,675,619	2,549,531	142,356
4	DEPRECIATION & AMORTIZATION [PAGE 5]		41,961,336	35,279,555	5,396,349	120,250	474,033	678,280	12,870
5	TAXES OTHER THAN INCOME [PAGE 9]		3,688,203	3,030,929	534,986	12,133	46,383	62,040	1,732
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		334,477,202	262,905,213	61,343,268	4,585,877	2,196,034	3,289,851	408,583
7	OPERATING INCOME BEFORE TAXES		121,889,665	73,235,799	28,471,049	1,585,144	7,917,956	9,584,758	1,094,958
8	INCOME TAXES		36,054,400	18,229,909	9,919,734	600,485	3,125,943	3,727,529	450,799
9	INVESTMENT TAX CREDIT	12	(360,239)	(303,156)	(45,387)	(1,034)	(4,190)	(6,373)	(101)
10	NET INCOME TAXES		35,694,161	17,926,754	9,874,348	599,451	3,121,753	3,721,157	450,698
11	OPERATING INCOME		86,195,504	55,309,045	18,596,702	985,694	4,796,203	5,863,601	644,259
12	RATE BASE [PAGE 10]		1,011,680,660	845,636,729	133,352,706	4,330,241	10,904,926	17,221,274	234,783
13	RATE OF RETURN EARNED ON RATE BASE		8.520%	6.541%	13.946%	22.763%	43.982%	34.049%	274.406%
14	UNITIZED RETURN		1.00	0.77	1.64	2.67	5.16	4.00	32.21

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - CURRENT @ CURRENT RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 2 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
1	TOTAL REVENUE [PAGE 6]		379,306,896	274,361,314	75,458,368	5,588,931	9,532,302	12,863,599	1,502,383
2	PRODUCTS PURCHASED [PAGE 7]		150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		137,753,458	115,373,505	17,601,228	419,877	1,667,138	2,549,371	142,340
4	DEPRECIATION & AMORTIZATION [PAGE 5]		41,961,336	35,279,555	5,396,349	120,250	474,033	678,280	12,870
5	TAXES OTHER THAN INCOME [PAGE 9]		3,688,203	3,030,929	534,986	12,133	46,383	62,040	1,732
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		333,601,624	262,004,465	61,133,959	4,577,391	2,187,553	3,289,691	408,566
7	OPERATING INCOME BEFORE TAXES		45,705,272	12,356,849	14,324,410	1,011,541	7,344,749	9,573,908	1,093,816
8	INCOME TAXES [PAGE 11]		4,442,828	(7,030,898)	4,049,798	362,476	2,888,099	3,723,027	450,326
9	INVESTMENT TAX CREDIT	12	(360,239)	(303,156)	(45,387)	(1,034)	(4,190)	(6,373)	(101)
10	NET INCOME TAXES		4,082,589	(7,334,053)	4,004,412	361,442	2,883,909	3,716,655	450,225
11	OPERATING INCOME		41,622,683	19,690,902	10,319,998	650,098	4,460,840	5,857,253	643,591
12	RATE BASE [PAGE 10]		1,011,680,660	845,636,729	133,352,706	4,330,241	10,904,926	17,221,274	234,783
13	RATE OF RETURN EARNED ON RATE BASE		4.114%	2.329%	7.739%	15.013%	40.907%	34.012%	274.121%
14	UNITIZED RETURN		1.00	0.57	1.88	3.65	9.94	8.27	66.63

COLUMBIA GAS OF PENNSYLVANIA, INC.
GROSS PLANT (Accounts 101 & 106)
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	301-305	INTANGIBLE PLANT	11	13,197,924	11,111,200	1,657,527	36,954	154,152	234,395	3,695
2	350-362	UNDERGROUND STORAGE PLANT	25	6,014,913	4,535,605	1,342,047	128,839	-	-	8,421
		DISTRIBUTION PLANT								
3	374.10	LAND - CITY GATE & M/L IND M&R	20	186,844	156,440	24,032	633	2,840	4,899	-
4	374.20	LAND - OTHER DISTRIBUTION	20	480,964	398,435	61,208	1,611	7,234	12,476	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	20	95,361	78,998	12,136	320	1,434	2,474	-
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	20	1,783,038	1,477,087	226,910	5,973	26,817	46,252	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		3	-	-	-	-	-	3
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	20	13	11	2	-	-	0	-
9	374.50	RIGHTS OF WAY	20	3,231,844	2,677,292	411,284	10,827	48,607	83,834	-
10	374.50	DIRECT - RIGHTS OF WAY		1,195	-	-	-	-	-	1,195
11	375.20	M & R STRUCTURES - CITY GATE	20	813,126	673,602	103,479	2,724	12,229	21,093	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	20	4,012	3,324	511	13	60	104	-
13	375.40	M & R STRUCTURES - REGULATING	20	2,714,399	2,248,635	345,434	9,093	40,825	70,412	-
14	375.60	M & R STRUCTURES - DIST. IND. M & R	17	87,692	(0)	58,671	5,195	17,109	6,718	-
15	375.70	M & R STRUCTURES - OTHER	11	4,150,247	3,494,052	521,230	11,621	48,475	73,708	1,162
16	375.71	M & R STRUCTURES - OTHER LEASED	11	1,031,960	868,797	129,604	2,890	12,053	18,328	289
17	375.80	M & R STRUCTURES - COMMUNICATION	20	16,515	13,681	2,102	55	248	428	-
18	376.00	MAINS	20	811,843,757	672,539,487	103,315,237	2,719,677	12,210,130	21,059,227	-
19	376.00	DIRECT - MAINS		98,881	-	-	-	-	-	98,881
20	376.08	MAINS-CSL REPLACEMENTS	20	23,059,830	19,102,994	2,934,594	77,250	346,820	598,172	-
21	376.30	MAINS-BARE STEEL	20	75,183,814	62,283,024	9,567,892	251,866	1,130,765	1,950,268	-
22	376.30	DIRECT - MAINS-BARE STEEL		118,511	-	-	-	-	-	118,511
23	376.80	MAINS-CAST IRON	20	739,405	612,531	94,097	2,477	11,121	19,180	-
24	378.10	M & R EQUIP - GENERAL	20	58,867	48,766	7,492	197	885	1,527	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	20	18,916,204	15,670,373	2,407,276	63,369	284,500	490,686	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		1,178	-	-	-	-	-	1,178
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	20	486,506	403,027	61,913	1,630	7,317	12,620	-
28	379.10	M & R EQUIP - CITY GATE	20	147,820	122,456	18,812	495	2,223	3,835	-
29	379.11	M & R EQUIP - EXCHANGE GAS	20	5,974	4,949	760	20	90	155	-
30	380.00	SERVICES	15	373,962,974	343,200,780	30,081,582	149,585	340,306	190,721	-
31	380.00	DIRECT - SERVICES		37,630	-	-	-	-	-	37,630
32	380.12	CSL REPLACEMENT	15	-	-	-	-	-	-	-
33	381.00	METERS	16	34,301,875	25,721,261	8,124,056	94,673	278,874	78,551	4,459
34	381.10	AUTOMATIC METER READING	16	20,548,041	15,407,948	4,866,598	56,713	167,056	47,055	2,671
35	382.00	METER INSTALLATIONS	16	35,468,816	26,596,292	8,400,435	97,894	288,362	81,224	4,611
36	383.00	HOUSE REGULATORS	16	10,741,363	8,054,411	2,543,984	29,646	87,327	24,598	1,396
37	384.00	HOUSE REG INSTALLATIONS	16	3,864,772	2,897,999	915,333	10,667	31,421	8,850	502
38	385.00	IND M&R EQUIPMENT	17	5,355,556	-	3,583,135	317,263	1,044,869	410,289	-
39	385.00	DIRECT - IND M&R EQUIPMENT		122,846	-	-	-	-	-	122,846
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	1,356,628	-	907,652	80,367	264,678	103,931	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	16,603	13,978	2,085	47	194	295	5
42	387.20	OTHER EQUIP ODORIZATION	11	121,943	102,662	15,315	341	1,424	2,166	34
43	387.42	OTHER EQUIP RADIO	11	130,407	109,788	16,378	365	1,523	2,316	37
44	387.44	OTHER EQUIP COMMUNICATION	11	664,599	559,519	83,467	1,861	7,763	11,803	186
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	259,436	218,417	32,583	726	3,030	4,608	73
46		TOTAL DISTRIBUTION PLANT		##########	##########	179,877,273	4,008,084	16,728,609	25,442,803	395,670
47	389-398	GENERAL PLANT	11	25,681,927	21,621,357	3,225,393	71,909	299,965	456,111	7,191
48	TOTAL GROSS PLANT			##########	##########	186,102,241	4,245,787	17,182,725	26,133,309	414,977

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEPRECIATION RESERVE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 4 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	301-305	INTANGIBLE PLANT	11	4,670,206	3,931,800	586,531	13,077	54,548	82,943	1,308
2	350-362	UNDERGROUND STORAGE PLANT	25	1,332,255	1,004,600	297,253	28,537	-	-	1,865
		DISTRIBUTION PLANT								
3	374.10	LAND - CITY GATE & M/L IND M&R	20	-	-	-	-	-	-	-
4	374.20	LAND - OTHER DISTRIBUTION	20	(24,311)	(20,140)	(3,094)	(81)	(366)	(631)	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	20	-	-	-	-	-	-	-
6	*374.40*	*LAND RIGHTS - OTHER DISTRIBUTION*	20	*635,353*	*526,333*	*80,855*	*2,128*	*9,556*	*16,481*	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		1	-	-	-	-	-	1
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	20	-	-	-	-	-	-	-
9	374.50	RIGHTS OF WAY	20	1,495,661	1,239,021	190,338	5,011	22,495	38,798	-
10	374.50	DIRECT - RIGHTS OF WAY		664	-	-	-	-	-	664
11	375.20	M & R STRUCTURES - CITY GATE	20	-	-	-	-	-	-	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	20	-	-	-	-	-	-	-
13	375.40	M & R STRUCTURES - REGULATING	20	789,197	653,779	100,433	2,644	11,870	20,472	-
14	375.60	M & R STRUCTURES - DIST. IND. M & R	17	71,206	-	47,640	4,218	13,892	5,455	-
15	375.70	M & R STRUCTURES - OTHER	11	2,143,906	1,804,933	269,253	6,003	25,041	38,076	600
16	375.71	M & R STRUCTURES - OTHER LEASED	11	971,923	818,252	122,064	2,721	11,352	17,261	272
17	375.80	M & R STRUCTURES - COMMUNICATION	20	5,681	4,706	723	19	85	147	-
18	376.00	MAINS	20	121,479,094	100,634,496	15,459,430	406,955	1,827,046	3,151,168	-
19	376.00	DIRECT - MAINS		58,002	-	-	-	-	-	58,002
20	376.08	MAINS-CSL REPLACEMENTS	20	-	-	-	-	-	-	-
21	376.30	MAINS-BARE STEEL	20	45,736,016	37,888,173	5,820,365	153,216	687,870	1,186,392	-
22	376.30	DIRECT - MAINS-BARE STEEL		96,966	-	-	-	-	-	96,966
23	376.80	MAINS-CAST IRON	20	12,008	9,948	1,528	40	181	312	-
24	378.10	M & R EQUIP - GENERAL	20	-	-	-	-	-	-	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	20	6,461,419	5,352,704	822,280	21,646	97,180	167,609	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		870	-	-	-	-	-	870
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	20	-	-	-	-	-	-	-
28	379.10	M & R EQUIP - CITY GATE	20	94,719	78,466	12,054	317	1,425	2,457	-
29	379.11	M & R EQUIP - EXCHANGE GAS	20	-	-	-	-	-	-	-
30	380.00	SERVICES	15	101,680,586	93,316,341	8,179,186	40,672	92,529	51,857	-
31	380.00	DIRECT - SERVICES		21,889	-	-	-	-	-	21,889
32	*380.12*	*CSL REPLACEMENT*	*15*	-	-	-	-	-	-	-
33	381.00	METERS	16	14,998,136	11,246,352	3,552,159	41,395	121,935	34,346	1,950
34	381.10	AUTOMATIC METER READING	16	4,440,562	3,329,755	1,051,703	12,256	36,102	10,169	577
35	382.00	METER INSTALLATIONS	16	10,435,222	7,824,851	2,471,478	28,801	84,838	23,897	1,357
36	383.00	HOUSE REGULATORS	16	2,868,259	2,150,764	679,319	7,916	23,319	6,568	373
37	384.00	HOUSE REG INSTALLATIONS	16	2,788,621	2,091,048	660,457	7,697	22,672	6,386	363
38	385.00	IND M&R EQUIPMENT	17	3,181,978	-	2,128,902	186,500	620,804	243,771	-
39	385.00	DIRECT - IND M&R EQUIPMENT		44,342	-	-	-	-	-	44,342
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	73,950	0	49,476	4,381	14,428	5,665	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	-	-	-	-	-	-	-
42	387.20	OTHER EQUIP ODORIZATION	11	-	-	-	-	-	-	-
43	387.42	OTHER EQUIP RADIO	11	-	-	-	-	-	-	-
44	387.44	OTHER EQUIP COMMUNICATION	11	-	-	-	-	-	-	-
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	545,616	459,349	68,524	1,528	6,373	9,690	153
46		TOTAL DISTRIBUTION PLANT		321,107,516	269,409,132	41,765,073	937,983	3,730,624	5,036,346	228,358
47	389-398	GENERAL PLANT	11	15,890,423	13,377,988	1,995,678	44,493	185,600	282,214	4,449
48	*TOTAL DEPRECIATION RESERVE*			343,000,400	287,723,520	44,644,535	1,024,090	3,970,772	5,401,503	235,980

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 5 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	301-305	INTANGIBLE PLANT	11	1,756,935	1,479,146	220,654	4,919	20,521	31,203	492
2	350-362	UNDERGROUND STORAGE PLANT	25	163,868	123,566	36,562	3,510	-	-	229
		DISTRIBUTION PLANT								
3	374.10	LAND - CITY GATE & M/L IND M&R	20	-	-	-	-	-	-	-
4	374.20	LAND - OTHER DISTRIBUTION	20	-	-	-	-	-	-	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	20	-	-	-	-	-	-	-
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	20	35,574	29,470	4,527	119	535	923	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		0	-	-	-	-	-	0
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	20	-	-	-	-	-	-	-
9	374.50	RIGHTS OF WAY	20	43,000	35,622	5,472	144	647	1,116	-
10	374.50	DIRECT - RIGHTS OF WAY		16	-	-	-	-	-	16
11	375.20	M & R STRUCTURES - CITY GATE	20	-	-	-	-	-	-	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	20	-	-	-	-	-	-	-
13	375.40	M & R STRUCTURES - REGULATING	20	81,608	67,605	10,385	273	1,227	2,117	-
14	375.60	M & R STRUCTURES - DIST. IND. M & R	17	973	0	651	58	190	75	-
15	375.70	M & R STRUCTURES - OTHER	11	161,680	136,117	20,305	453	1,888	2,871	45
16	375.71	M & R STRUCTURES - OTHER LEASED	11	182,501	153,646	22,920	511	2,132	3,241	51
17	375.80	M & R STRUCTURES - COMMUNICATION	20	342	283	44	1	5	9	-
18	376.00	MAINS	20	16,635,509	13,781,022	2,117,035	55,729	250,198	431,525	-
19	376.00	DIRECT - MAINS		1,641	-	-	-	-	-	1,641
20	376.08	MAINS-CSL REPLACEMENTS	20	-	-	-	-	-	-	-
21	376.30	MAINS-BARE STEEL	20	1,725,309	1,429,264	219,563	5,780	25,949	44,755	-
22	376.30	DIRECT - MAINS-BARE STEEL		2,501	-	-	-	-	-	2,501
23	376.80	MAINS-CAST IRON	20	409	339	52	1	6	11	-
24	378.10	M & R EQUIP - GENERAL	20	-	-	-	-	-	-	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	20	563,688	466,965	71,735	1,888	8,478	14,622	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		29	-	-	-	-	-	29
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	20	-	-	-	-	-	-	-
28	379.10	M & R EQUIP - CITY GATE	20	5,023	4,161	639	17	76	130	-
29	379.11	M & R EQUIP - EXCHANGE GAS	20	-	-	-	-	-	-	-
30	380.00	SERVICES	15	10,309,953	9,461,656	829,333	4,124	9,382	5,258	-
31	380.00	DIRECT - SERVICES		963	-	-	-	-	-	963
32	380.12	CSL REPLACEMENT	15	-	-	-	-	-	-	-
33	381.00	METERS	16	835,931	626,823	197,982	2,307	6,796	1,914	109
34	381.10	AUTOMATIC METER READING	16	1,778,260	1,333,428	421,163	4,908	14,457	4,072	231
35	382.00	METER INSTALLATIONS	16	707,167	530,269	167,485	1,952	5,749	1,619	92
36	383.00	HOUSE REGULATORS	16	284,993	213,702	67,498	787	2,317	653	37
37	384.00	HOUSE REG INSTALLATIONS	16	72,465	54,338	17,163	200	589	166	9
38	385.00	IND M&R EQUIPMENT	17	245,096	0	163,982	14,520	47,818	18,777	-
39	385.00	DIRECT - IND M&R EQUIPMENT		4,644	-	-	-	-	-	4,644
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	4,212	-	2,818	250	822	323	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	-	-	-	-	-	-	-
42	387.20	OTHER EQUIP ODORIZATION	11	-	-	-	-	-	-	-
43	387.42	OTHER EQUIP RADIO	11	-	-	-	-	-	-	-
44	387.44	OTHER EQUIP COMMUNICATION	11	-	-	-	-	-	-	-
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	49,407	41,595	6,205	138	577	878	14
46		TOTAL DISTRIBUTION PLANT		33,732,894	28,366,604	4,346,957	94,159	379,838	535,053	10,382
47	389-398	GENERAL PLANT	11	1,443,308	1,215,107	181,265	4,041	16,858	25,633	404
48		NET DEPRECIATION & AMORTIZATION EXPENSE		37,097,005	31,184,323	4,785,438	106,630	417,217	591,890	11,508
49		AMORTIZATION OF NET NEGATIVE SALVAGE	11	4,864,331	4,095,232	610,911	13,620	56,815	86,391	1,362
50	TOTAL AMORTIZATION AND DEPRECIATION EXPENSE			41,961,336	35,279,555	5,396,349	120,250	474,033	678,280	12,870

COLUMBIA GAS OF PENNSYLVANIA, INC.
OPERATING REVENUE @ PROPOSED & CURRENT RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 6 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
		PROPOSED OPERATING REVENUE								
		SALES REVENUE								
1	480/481	SALES BASE REVENUE		214,061,481	173,800,330	38,100,661	2,130,998	-	-	19,492
2		USP REVENUE		8,309,047	8,309,047	-	-	-	-	-
3		STAS REVENUE		-	-	-	-	-	-	-
4		UNBUNDLED UNCOLLECTIBLES REVENUE		1,848,276	1,363,655	484,621	-	-	-	-
5		GAS PROCUREMENT REVENUE	2	465,287	332,745	118,253	13,410	-	-	879
6		GAS COST REVENUE		141,900,550	102,129,786	35,494,009	4,025,130	-	-	251,625
7		TOTAL SALES REVENUE		366,574,641	285,935,563	74,197,544	6,169,538	-	-	271,996
		TRANSPORTATION REVENUE								
8	489.00	TRANSPORTATION BASE REVENUE		73,174,899	40,288,371	13,273,361	-	9,900,113	9,492,046	221,008
9		USP REVENUE		2,549,024	2,549,024	-	-	-	-	-
10		STAS REVENUE		-	-	-	-	-	-	-
11		FLEX REVENUE		4,613,061	-	32,146		201,904	3,369,813	1,009,198
12		GAS COST REVENUE		8,298,077	6,190,690	2,107,387	-	-	-	-
13		TOTAL TRANSPORTATION REVENUE		88,635,061	49,028,085	15,412,894	-	10,102,017	12,861,859	1,230,206
		MISCELLANEOUS REVENUE								
14	487.00	FORFEITED DISCOUNTS	10	944,367	766,231	156,633	944	9,661	9,614	1,284
15	488.00	MISCELLANEOUS REVENUE	6	146,687	133,632	12,845	28	147	32	3
16	493.00	RENTS	11	173,011	145,656	21,729	484	2,021	3,073	48
17	495.00	OTHER	6	144,725	131,845	12,674	28	145	32	3
18		TOTAL MISCELLANEOUS REVENUE		1,408,790	1,177,364	203,880	1,484	11,973	12,751	1,339
19		TOTAL PROPOSED OPERATING REVENUE		456,618,492	336,141,012	89,814,318	6,171,022	10,113,990	12,874,610	1,503,541
		CURRENT OPERATING REVENUE								
		SALES REVENUE								
20	480/481	SALES BASE REVENUE		138,032,974	112,543,257	23,906,093	1,564,132	-	-	19,492
21		USP REVENUE		8,309,047	8,309,047	-	-	-	-	-
22		STAS REVENUE		(181,366)	(151,797)	(27,731)	(1,815)	-	-	(23)
23		UNBUNDLED UNCOLLECTIBLES REVENUE		1,848,276	1,363,655	484,621	-	-	-	-
24		GAS COST REVENUE		141,900,550	102,129,786	35,494,009	4,025,130	-	-	251,625
25		TOTAL SALES REVENUE		289,909,481	224,193,948	59,856,992	5,587,447	-	-	271,094
		TRANSPORTATION REVENUE								
26	489.00	TRANSPORTATION BASE REVENUE		72,604,033	40,288,371	13,273,361	-	9,329,247	9,492,046	221,008
27		USP REVENUE		2,549,024	2,549,024	-	-	-	-	-
28		STAS REVENUE		(75,570)	(38,083)	(15,398)	-	(10,822)	(11,011)	(256)
29		FLEX REVENUE		4,613,061	-	32,146	-	201,904	3,369,813	1,009,198
30		GAS COST REVENUE		8,298,077	6,190,690	2,107,387	-	-	-	-
31		TOTAL TRANSPORTATION REVENUE		87,988,625	48,990,002	15,397,496	-	9,520,329	12,850,848	1,229,950
		MISCELLANEOUS REVENUE								
32	487.00	FORFEITED DISCOUNTS	10	944,367	766,231	156,633	944	9,661	9,614	1,284
33	488.00	MISCELLANEOUS REVENUE	6	146,687	133,632	12,845	28	147	32	3
34	493.00	RENTS	11	173,011	145,656	21,729	484	2,021	3,073	48
35	495.00	OTHER	6	144,725	131,845	12,674	28	145	32	3
36		TOTAL MISCELLANEOUS REVENUE		1,408,790	1,177,364	203,880	1,484	11,973	12,751	1,339
37		TOTAL CURRENT OPERATING REVENUE		379,306,896	274,361,314	75,458,368	5,588,931	9,532,302	12,863,599	1,502,383

COLUMBIA GAS OF PENNSYLVANIA, INC.
PRODUCTION & DISTRIBUTION O&M EXPENSES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 7 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
		PURCHASED GAS EXPENSES								
1		GAS PURCHASED COST		149,947,002	108,320,476	37,601,396	4,025,130	-	-	251,625
2	807.00	PURCHASED GAS EXPENSE	4	1,036,138	747,242	259,387	27,769	-	-	1,741
3	807.00	GAS PROCUREMENT EXPENSE	4	465,287	335,556	116,480	12,470	-	-	782
4		TOTAL PURCHASED GAS		151,448,427	109,403,274	37,977,263	4,065,368	-	-	254,147
		UNDERGROUND STORAGE OPERATIONS EXPENSES								
5	816.00	WELLS	25	10,754	8,109	2,389	230	-	-	15
6	817.00	LINES	25	37,625	28,371	8,395	806	-	-	53
7	818.00	COMPRESSOR STATION	25	150,458	113,455	33,570	3,223	-	-	211
8	820.00	M & R	25	15,840	11,944	3,534	339	-	-	22
9	821.00	PURIFICATION	25	3,082	2,324	688	66	-	-	4
10	823.00	GAS LOSSES	25	2,052	1,547	458	44	-	-	3
11	825.00	STORAGE WELL ROYALTIES	25	5,977	4,507	1,334	128	-	-	8
12		TOTAL UNDERGROUND STORAGE OPERATIONS		225,787	170,257	50,378	4,836	-	-	316
		UNDERGROUND STORAGE MAINTENANCE EXPENSES								
13	832.00	WELLS	25	7,823	5,899	1,745	168	-	-	11
14	834.00	COMPRESSOR STATION	25	6,230	4,698	1,390	134	-	-	9
15	836.00	PURIFICATION	25	6,789	5,120	1,515	145	-	-	10
16		TOTAL UNDERGROUND STORAGE MAINTENANCE		20,843	15,717	4,650	447	-	-	29
17		TOTAL UNDERGROUND STORAGE		246,630	185,974	55,028	5,283	-	-	345
		DISTRIBUTION OPERATIONS EXPENSES								
18	870.00	SUPERVISION & ENGINEERING	18	4,666,895	3,816,353	697,467	15,401	60,110	76,724	840
19	871.00	LOAD DISPATCHING	13	124,644	103,231	15,859	418	1,875	3,232	30
20	874.00	MAINS & SERVICES	14	10,868,086	9,263,954	1,234,723	27,062	118,788	201,386	2,174
21	875.00	M & R - GENERAL	13	590,194	488,805	75,090	1,977	8,877	15,304	142
22	876.00	M & R - INDUSTRIAL	17	245,982	-	164,574	14,572	47,991	18,845	-
23	878.00	METERS & HOUSE REGULATORS	16	2,455,745	1,841,440	581,619	6,778	19,965	5,624	319
24	879.00	CUSTOMER INSTALLATIONS	16	4,813,089	3,609,095	1,139,932	13,284	39,130	11,022	626
25	880.00	OTHER	18	4,881,051	3,991,480	729,473	16,108	62,868	80,245	879
26	881.00	RENTS	18	273,398	223,571	40,859	902	3,521	4,495	49
27		TOTAL DISTRIBUTION OPERATIONS		28,919,083	23,357,929	4,679,597	96,501	363,125	416,875	5,058
		DISTRIBUTION MAINTENANCE EXPENSES								
28	885.00	SUPERVISION & ENGINEERING	18	51,399	42,032	7,682	170	662	845	9
29	886.00	STRUCTURES AND IMPROVEMENTS	13	52,374	43,376	6,664	176	788	1,358	13
30	887.00	MAINS	13	10,193,632	8,442,468	1,296,936	34,149	153,312	264,321	2,447
31	889.00	M & R - GENERAL	13	609,180	504,529	77,506	2,041	9,162	15,796	146
32	890.00	M & R - INDUSTRIAL	17	127,109	-	85,042	7,530	24,799	9,738	-
33	892.00	SERVICES	15	3,008,381	2,760,911	241,994	1,203	2,738	1,534	-
34	893.00	METERS & HOUSE REGULATORS	16	286,063	214,505	67,751	790	2,326	555	37
35	894.00	OTHER EQUIPMENT	18	796,193	651,087	118,991	2,627	10,255	13,089	143
36		TOTAL DISTRIBUTION MAINTENANCE		15,124,330	12,658,907	1,902,565	48,685	204,041	307,337	2,795
37		TOTAL DISTRIBUTION		44,043,414	36,016,836	6,582,162	145,186	567,166	724,211	7,853

COLUMBIA GAS OF PENNSYLVANIA, INC.
OTHER O&M EXPENSES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 8 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
		CUSTOMER ACCOUNTS EXPENSES								
1	901.00	SUPERVISION	6	-	-	-	-	-	-	-
2	902.00	METER READING	6	2,126,147	1,936,920	186,187	404	2,126	468	43
3	903.00	COLLECTING-DELINQUENT ACCTS	6	1,072,108	976,690	93,885	204	1,072	236	21
4	903.00	COLLECTING-CURRENT ACCTS	6	7,959	7,251	697	2	8	2	0
5	903.00	BILLING & ACCOUNTING	6	5,797,611	5,281,623	507,697	1,102	5,798	1,276	116
6	903.00	RENDERING BILLS	6	2,484,720	2,263,580	217,587	472	2,485	547	50
7	904.00	UNCOLLECTIBLES-DIS REVENUE	7	3,037,943	2,601,391	415,165	3,949	7,139	9,509	790
8	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	7	38,961	33,362	5,324	51	92	122	10
9	904.00	UNCOLLECTIBLES-UNBUNDLED GAS	23	1,848,276	1,593,898	254,378	-	-	-	-
10	904.00	DIRECT USP UNCOLLECTIBLES		8,469,295	8,469,295	-	-	-	-	-
11	905.00	MISCELLANEOUS	6	17,448	15,895	1,528	3	17	4	0
12	921.00	OFFICE SUPPLIES & EXPENSES	6	4,212	3,837	369	1	4	1	-
13		TOTAL CUSTOMER ACCOUNTS		24,904,680	23,183,743	1,682,817	6,187	18,741	12,163	1,030
		CUST SERVICE & INFORMATION EXPENSES								
14	907.00	SUPERVISION	6	-	-	-	-	-	-	-
15	908.00	CUSTOMER ASSISTANCE	6	613,463	558,877	53,721	117	614	135	-
16	908.00	DIRECT USP/LIURP/HEEP		2,388,776	2,388,776	-	-	-	-	-
17	909.00	INFORMATIONAL & INSTRUCTIONAL EXPENSES	6	38,185	34,786	3,344	7	38	8	1
18	910.00	MISCELLANEOUS	6	600,792	547,321	52,611	114	601	132	12
19	910.00	LARGE CUSTOMER RELATIONS	21	986,406	0	113,091	12,567	245,033	552,890	62,824
20	921.00	OFFICE SUPPLIES & EXPENSES	6	9,085	8,277	796	2	9	2	-
21	931.00	RENTS - GENERAL	6	140	128	12	-	-	-	-
22		TOTAL CUST SERVICE & INFORMATION		4,636,846	3,538,165	223,575	12,807	246,295	553,168	62,837
		SALES EXPENSES								
23	912.00	DEMONSTRATION	6	650,917	592,985	57,001	124	651	143	13
24	913.00	ADVERTISING	6	128,865	117,396	11,285	25	129	28	3
25		TOTAL SALES		779,782	710,381	68,286	148	780	172	16
		ADMINISTRATIVE AND GENERAL EXPENSES								
26	920.00	SALARIES	19	3,908,071	3,215,053	538,493	13,327	53,502	82,929	4,768
27	921.00	OFFICE SUPPLIES & EXPENSES	19	2,016,774	1,659,139	277,891	6,877	27,610	42,796	2,461
28	922.00	ADMIN. EXPENSE TRANSFERRED	19	-	-	-	-	-	-	-
29	923.00	OUTSIDE SERVICES EMPLOYED	19	41,245,654	33,931,562	5,683,239	140,648	564,653	875,233	50,320
30	924.00	PROPERTY INSURANCE	19	157,493	129,565	21,701	537	2,156	3,342	192
31	925.00	INJURIES AND DAMAGES	19	3,725,912	3,065,196	513,393	12,705	51,008	79,064	4,546
32	926.00	EMPLOYEE PENSIONS & BENEFITS	24	8,294,725	6,769,491	1,262,955	28,119	103,850	127,656	2,654
33	928.00	REGULATORY COMMISSION EXPENSES	19	1,428,131	1,174,880	196,782	4,870	19,551	30,305	1,742
34	930.00	MISCELLANEOUS GENERAL	19	568,725	467,873	78,365	1,939	7,786	12,068	694
35	931.00	RENTS-GENERAL	19	295,199	242,851	40,675	1,007	4,041	6,264	360
36		TOTAL ADMINISTRATIVE & GENERAL		61,640,682	50,655,609	8,613,494	210,029	834,156	1,259,657	67,736
37		TOTAL O & M EXPENSES		287,700,461	223,693,981	55,202,624	4,445,007	1,667,138	2,549,371	393,965

COLUMBIA GAS OF PENNSYLVANIA, INC.
TAXES OTHER THAN INCOME TAXES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 9 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
		FEDERAL TAXES								
1	408.00	FEDERAL UNEMPLOYMENT	24	45,196	36,885	6,882	153	566	696	15
2	408.00	FICA	24	2,190,869	1,788,012	333,582	7,427	27,430	33,718	701
3		TOTAL FEDERAL TAXES		2,236,065	1,824,897	340,463	7,580	27,996	34,413	716
		STATE TAXES								
4	408.00	PA PROPERTY TAXES	11	642,142	540,613	80,647	1,798	7,500	11,404	180
5	408.00	PA STATE UNEMPLOYMENT	24	161,920	132,146	24,654	549	2,027	2,492	52
6	408.00	STATE CAPITAL STOCK TAX	11	-	-	-	-	-	-	-
7	408.00	LICENSE AND FRANCHISE TAX	11	6,251	5,263	785	18	73	111	2
8	408.00	STATE SALES AND USE TAX	19	614,394	505,444	84,657	2,095	8,411	13,037	750
9	408.00	OTHER	19	27,431	22,567	3,780	94	376	582	34
10		TOTAL STATE TAXES		1,452,138	1,206,032	194,523	4,553	18,387	27,627	1,017
11		TOTAL TAXES OTHER THAN INCOME		3,688,203	3,030,929	534,986	12,133	46,383	62,040	1,732

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE BASE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 10 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	101-107	GROSS PLANT [PAGE 3]		1,477,108,215	1,243,029,177	186,102,241	4,245,787	17,182,725	26,133,309	414,977
2	117.00	GAS STORED UNDERGROUND - NON CURRENT	25	3,794,990	2,861,650	846,738	81,289	-	-	5,313
3	108-111	DEPRECIATION RESERVE [PAGE 4]		(343,000,400)	(287,723,520)	(44,644,535)	(1,024,090)	(3,970,772)	(5,401,503)	(235,980)
4	117.00	GAS LOST-UNDERGROUND STORAGE	1	(163,458)	(99,739)	(37,756)	(1,944)	(8,717)	(15,303)	-
5		NET PLANT		1,137,739,347	958,067,569	142,266,688	3,301,042	13,203,236	20,716,503	184,310
		WORKING CAPITAL								
6	154.00	MATERIALS & SUPPLIES	11	663,015	558,186	83,268	1,856	7,744	11,775	186
7	164.00	GAS STORED UNDERGROUND - FSS	25	74,526,147	56,197,186	16,628,274	1,596,350	-	-	104,337
8	165.00	PREPAYMENTS	19	1,651,928	1,358,992	227,619	5,633	22,615	35,054	2,015
9		CASH WORKING CAPITAL - GAS PURCHASES	4	-	-	-	-	-	-	-
10		CASH WORKING CAPITAL - ALL OTHER	19	-	-	-	-	-	-	-
11		TOTAL WORKING CAPITAL		76,841,090	58,114,364	16,939,161	1,603,840	30,359	46,829	106,538
		DEFERRED INCOME TAXES								
12	190.00	ACCUMULATED DEF INCOME TAX	12	3,351,427	2,820,360	422,246	9,619	38,977	59,287	938
13	282.00	ACCUMULATED DEF INCOME TAX	12	(203,338,966)	(171,117,874)	(25,618,676)	(583,583)	(2,364,832)	(3,597,066)	(56,935)
14	283.00	ACCUMULATED DEF INCOME TAX	12	(23,454)	(19,737)	(2,955)	(67)	(273)	(415)	(7)
15		TOTAL DEFERRED INCOME TAXES		(200,010,993)	(168,317,251)	(25,199,385)	(574,032)	(2,326,128)	(3,538,195)	(56,003)
16	235.00	CUSTOMER DEPOSITS	9	(2,671,287)	(2,044,844)	(626,444)	-	-	-	-
17	252.00	CUSTOMER ADVANCES	11	(217,497)	(183,109)	(27,315)	(609)	(2,540)	(3,863)	(61)
18		RATE BASE		1,011,680,660	845,636,729	133,352,706	4,330,241	10,904,926	17,221,274	234,783

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATE/FEDERAL INCOME TAXES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 11 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
	STATE INCOME TAX								
1	OPERATING INCOME BEFORE TAXES (PG. 2, LINE 8)		45,705,272	12,356,849	14,324,410	1,011,541	7,344,749	9,573,908	1,093,816
2	STATUTORY ADJUSTMENTS	12	(37,630,943)	(31,667,943)	(4,741,123)	(108,001)	(437,648)	(665,691)	(10,537)
3	INTEREST ON DEBT		(26,607,201)	(22,240,246)	(3,507,176)	(113,885)	(286,800)	(452,920)	(6,175)
4	PA BONUS DEPRECIATION ADJUSTMENT	12	(5,114,711)	(4,304,234)	(644,402)	(14,679)	(59,484)	(90,479)	(1,432)
5	STATE TAXABLE INCOME		(23,647,583)	(45,855,574)	5,431,708	774,975	6,560,816	8,364,817	1,075,673
6	NET OPERATING LOSS DEDUCTION	12	-	-	-	-	-	-	-
	STATE TAXABLE INCOME		(23,647,583)	(45,855,574)	5,431,708	774,975	6,560,818	8,364,817	1,075,673
7	STATE NET INCOME TAX @ 9.99%		(2,362,394)	(4,580,972)	542,628	77,420	655,426	835,645	107,460
8	DEFERRED INCOME TAXES	12	1,566,210	1,318,028	197,327	4,495	18,215	27,706	439
9	STATE INCOME TAX		(796,184)	(3,262,943)	739,954	81,915	673,641	863,352	107,898
	FEDERAL INCOME TAX								
10	OPERATING INCOME BEFORE TAXES (PG. 2, LINE 8)		45,705,272	12,356,849	14,324,410	1,011,541	7,344,749	9,573,908	1,093,816
11	STATE NET INCOME TAX (LINE 7)		2,362,394	4,580,972	(542,628)	(77,420)	(655,426)	(835,645)	(107,460)
12	STATUTORY ADJUSTMENTS (LINES 2 & 3)	12	(64,238,144)	(53,908,189)	(8,248,299)	(221,886)	(724,447)	(1,118,611)	(16,712)
13	FEDERAL TAXABLE INCOME		(16,170,478)	(36,970,369)	5,533,483	712,234	5,964,876	7,619,651	969,645
14	FEDERAL INCOME TAX @ 35%		(5,659,667)	(12,939,629)	1,936,719	249,282	2,087,707	2,666,878	339,376
15	DEFERRED INCOME TAXES	12	16,164,641	13,603,192	2,036,583	46,393	187,995	285,953	4,526
16	TAX REFUND AMORTIZATION	12	(4,089,420)	(3,441,411)	(515,226)	(11,737)	(47,560)	(72,342)	(1,145)
17	FLOW BACK OF EXCESS DEFERRED TAXES	12	(628,368)	(528,797)	(79,168)	(1,803)	(7,308)	(11,116)	(176)
18	EFFECT OF CNIT DEFERRED TAX ON FIT	12	(548,174)	(461,310)	(69,064)	(1,573)	(6,375)	(9,697)	(154)
19	FEDERAL INCOME TAX		5,239,012	(3,767,954)	3,309,844	280,561	2,214,458	2,859,676	342,427
20	STATE NET INCOME TAX (LINE 9)		(796,184)	(3,262,943)	739,954	81,915	673,641	863,352	107,898
21	TOTAL INCOME TAXES		4,442,828	(7,030,898)	4,049,798	362,476	2,888,099	3,723,027	450,326

COLUMBIA GAS OF PENNSYLVANIA, INC.
ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 12 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	DESCRIPTION (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	RS/RDS (D)	SGS/SGDS (E)	LGS (F)	SDS (G)	LDS (H)	MDS (I)
1	DESIGN DAY	1	781,900	477,100	180,600	9,300	41,700	73,200	0
2	PERCENT		100.000%	61.018%	23.098%	1.189%	5.333%	9.362%	0.000%
3	THROUGHPUT EXCLUDING TRANSPORTATION	2	32,319,197	23,112,788	8,213,924	931,484	0	0	61,000
4	PERCENT		100.000%	71.514%	25.415%	2.882%	0.000%	0.000%	0.189%
5	THROUGHPUT EXCLUDING MDS	3	71,872,223	32,785,788	13,343,450	931,484	7,023,159	17,788,342	0
6	PERCENT		100.000%	45.617%	18.566%	1.296%	9.772%	24.750%	0.000%
7	GAS PURCHASED EXPENSE	4	150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
8	PERCENT		100.000%	72.118%	25.034%	2.680%	0.000%	0.000%	0.168%
9	COMPOSITE ALLOCATORS 1 & 3	5							
10	PERCENT		100.000%	61.213%	23.975%	0.712%	4.328%	9.772%	0.000%
11	AVERAGE NO. OF CUSTOMERS	6	415,347	378,379	36,372	79	416	91	10
12	PERCENT		100.000%	91.099%	8.757%	0.019%	0.100%	0.022%	0.002%
13	DISTRIBUTION UNCOLLECTIBLES	7	3,076,904	2,634,761	420,478	4,012	7,222	9,629	802
14	PERCENT		100.000%	85.630%	13.666%	0.130%	0.235%	0.313%	0.026%
15	CURRENT GMB/GTS REVENUE	8	32,051,476	-	2,862,902	5,587,447	9,520,329	12,850,848	1,229,950
16	PERCENT		100.000%	0.000%	8.932%	17.433%	29.703%	40.094%	3.837%
17	DIRECT ASSIGNMENT - CUSTOMER DEPOSITS	9	1,962,296	1,502,111	460,185	-	-	-	-
18	PERCENT		100.000%	76.549%	23.451%	0.000%	0.000%	0.000%	0.000%
19	FORFEITED DISCOUNTS	10	751,992	610,142	124,726	753	7,695	7,653	1,024
20	PERCENT		100.000%	81.137%	16.586%	0.100%	1.023%	1.018%	0.136%
21	DIST. PLANT EXCL ACCTS 375.70, 375.71, & 387	11	1,425,838,257	1,200,393,802	179,076,612	3,990,233	16,654,146	25,329,579	393,885
22	PERCENT		100.000%	84.189%	12.559%	0.280%	1.168%	1.776%	0.028%
23	GROSS PLANT	12	1,477,108,215	1,243,029,177	186,102,241	4,245,787	17,182,725	26,133,309	414,977
24	PERCENT		100.000%	84.153%	12.599%	0.287%	1.163%	1.769%	0.028%

COLUMBIA GAS OF PENNSYLVANIA, INC.
ALLOCATION FACTORS (CONT.)
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 13 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	DESCRIPTION (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	RS/RDS (D)	SGS/SGDS (E)	LGS (F)	SDS (G)	LDS (H)	MDS (I)
1	MAINS - ACCOUNT 376	13	911,044,198	754,538,035	115,911,819	3,051,270	13,698,835	23,626,847	217,392
2	PERCENT		100.000%	82.821%	12.723%	0.335%	1.504%	2.593%	0.024%
3	COMPOSITE DIRECT PLANT - ACCTS 376 & 380	14	1,285,044,803	1,097,738,815	145,993,401	3,200,855	14,039,142	23,817,569	255,022
4	PERCENT		100.000%	85.424%	11.361%	0.249%	1.093%	1.853%	0.020%
5	DIRECT ASSIGNMENT - SERVICES	15	228,607,626	209,802,788	18,388,728	91,824	208,528	115,758	-
6	PERCENT		100.000%	91.774%	8.044%	0.040%	0.091%	0.051%	0.000%
7	DIRECT ASSIGNMENT - METERS	16	24,235,911	18,173,549	5,739,937	66,820	196,940	55,413	3,252
8	PERCENT		100.000%	74.986%	23.684%	0.276%	0.813%	0.229%	0.013%
9	DIRECT ASSIGNMENT - IND M & R	17	6,712,184	-	4,490,787	397,657	1,309,527	514,212	-
10	PERCENT		100.000%	0.000%	66.905%	5.924%	19.510%	7.661%	0.000%
11	OTHER DISTRIBUTION O & M EXPENSES	18	33,374,478	27,292,314	4,987,689	109,978	429,750	548,814	5,933
12	PERCENT		100.000%	81.776%	14.945%	0.330%	1.288%	1.644%	0.018%
13	O & M EXCL GAS PUR, UNCOLLECTIBLES, & A & G	19	60,329,525	49,631,174	8,312,866	205,848	825,751	1,280,083	73,803
14	PERCENT		100.000%	82.267%	13.779%	0.341%	1.369%	2.122%	0.122%
15	MINIMUM SYSTEM MAINS	20							
16	PERCENT		100.000%	82.841%	12.726%	0.335%	1.504%	2.594%	0.000%
17	LARGE CUSTOMER RELATIONS	21	157	-	18	2	39	88	10
18	PERCENT		100.00%	0.000%	11.465%	1.274%	24.841%	56.051%	6.369%
19	AVERAGE - ALLOCATORS 5 & 20	22							
20	PERCENT		100.00%	72.026%	18.351%	0.524%	2.916%	6.183%	0.000%
21	UNBUNDLED UNCOLLECTIBLES	23	1,848,276	1,593,907	254,369	-	-	-	-
22	PERCENT		100.000%	86.237%	13.763%	0.000%	0.000%	0.000%	0.000%
23	LABOR	24	24,202,825	19,752,433	3,685,241	81,995	302,939	372,366	7,851
24	PERCENT		100.000%	81.612%	15.226%	0.339%	1.252%	1.539%	0.032%
25	SALES AND CHOICE TRANSPORTATION	25	43,479,194	32,785,788	9,700,922	931,484	-	-	61,000
26	PERCENT		100.000%	75.406%	22.312%	2.142%	0.000%	0.000%	0.140%

COLUMBIA GAS OF PENNSYLVANIA, INC.
CUSTOMER BASED COSTS - SYSTEM CHARGE CALCULATION WITH MAINS COMPONENT
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 14 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D)	RS/RDS (E)	SGS/SGDS (F)	LGS (G)	SDS (H)	LDS (I)	MDS (J)
				$	$	$	$	$	$	$
1	874.00	MAINS & SERVICES [1]	14	3,137,834	2,680,463	356,489	7,813	34,297	58,144	628
2	875.00	M & R - GENERAL	13	590,194	488,805	75,090	1,977	8,877	15,304	142
3	876.00	M & R - INDUSTRIAL	17	245,982	-	164,574	14,572	47,991	18,845	-
4	878.00	METERS & HOUSE REGULATORS	16	2,455,745	1,841,440	581,819	6,778	19,965	5,624	319
5	879.00	CUSTOMER INSTALLATIONS	16	4,813,089	3,609,095	1,139,932	13,284	39,130	11,022	626
6	887.00	MAINS [2]	13	5,276,224	4,369,821	671,294	17,675	79,354	136,812	1,266
7	889.00	M & R - GENERAL	13	609,180	504,529	77,506	2,041	9,162	15,796	146
8	890.00	M & R - INDUSTRIAL	17	127,109	-	85,042	7,530	24,799	9,738	-
9	892.00	SERVICES [3]	15	2,984,103	2,738,631	240,041	1,194	2,716	1,522	-
10	893.00	METERS & HOUSE REGULATORS	16	286,063	214,504	67,751	790	2,326	655	37
11		TOTAL DISTRIBUTION		20,525,522	16,447,288	3,459,339	73,654	268,616	273,461	3,164
12	901.00	SUPERVISION	6	-	-	-	-	-	-	-
13	902.00	METER READING	6	2,126,147	1,936,920	186,187	404	2,126	468	43
14	903.00	COLLECTING-DELINQUENT ACCTS	6	1,072,108	976,690	93,884	204	1,072	236	21
15	903.00	COLLECTING-CURRENT ACCTS	6	7,959	7,251	697	2	8	2	0
16	903.00	BILLING & ACCOUNTING	6	5,797,611	5,281,623	507,697	1,102	5,798	1,275	116
17	903.00	RENDERING BILLS	6	2,484,720	2,263,580	217,587	472	2,485	547	50
18	904.00	UNCOLLECTIBLES-DIS REVENUE	7	3,037,943	2,601,391	415,165	3,949	7,139	9,509	790
19	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	7	38,961	33,362	5,324	51	92	122	10
20	905.00	MISCELLANEOUS	6	17,448	15,895	1,528	3	17	4	0
21	921.00	OFFICE SUPPLIES & EXPENSES	6	4,212	3,837	369	1	4	1	0
22		TOTAL CUSTOMER ACCOUNTS		14,587,109	13,120,549	1,428,438	6,187	18,741	12,163	1,030
23	907.00	SUPERVISION	6	-	-	-	-	-	-	-
24	908.00	CUSTOMER ASSISTANCE	6	613,463	558,865	53,721	117	613	135	12
25	909.00	INFORMATIONAL & INSTRUCTIONAL EXPENSES	6	38,185	34,786	3,344	7	38	8	1
26	910.00	MISCELLANEOUS	6	600,792	547,321	52,611	114	601	132	12
27	910.00	LARGE CUSTOMER RELATIONS	21	986,406	-	113,091	12,567	245,033	552,890	62,824
28	921.00	OFFICE SUPPLIES & EXPENSES	6	9,085	8,276	796	2	9	2	0
29	931.00	RENTS - GENERAL	6	140	128	12	0	0	0	0
30		TOTAL CUST SERVICE & INFORMATION		2,248,070	1,149,376	223,575	12,807	246,295	553,168	62,849
31	912.00	DEMONSTRATION	6	650,917	592,985	57,001	124	651	143	13
32	913.00	ADVERTISING	6	128,865	117,396	11,285	24	129	28	3
33		TOTAL SALES		779,782	710,381	68,285	148	780	172	16
34	920-931	CUSTOMER-RELATED A&G [4]		30,057,846	24,701,195	4,200,198	102,416	406,760	614,247	33,030
35	TOTAL CUST-RELATED O&M [LINES 11, 22, 30, 33 & 34]			68,198,328	56,128,789	9,378,836	195,212	941,191	1,453,210	100,089
36	DEPRECIATION & AMORTIZATION EXPENSE [PAGE 3, LINE 20]			29,960,335	25,311,942	3,861,122	78,634	305,285	393,434	9,917
37	INCOME TAXES			25,551,095	21,727,678	3,118,783	63,214	257,911	379,343	4,167
38	RETURN ON RATE BASE [PAGE 2, LINE 47]			52,149,831	44,346,230	6,365,441	129,020	526,396	774,239	8,505
39		TOTAL ANNUAL CUSTOMER-BASED COST		175,859,589	147,514,639	22,725,182	466,079	2,030,783	3,000,227	122,679
40		AVERAGE ANNUAL CUSTOMER BILLS [5]		5,050,351	4,603,511	439,658	945	5,028	1,101	108
41		**MONTHLY CUSTOMER BASED COST/BILL**		**$ 34.82**	**$ 32.04**	**$ 51.69**	**$ 493.21**	**$ 403.89**	**$ 2,725.00**	**$ 1,135.91**

[1] MAINS AND SERVICES @ 28.872% OF TOTAL ACCOUNT 874.
[2] MAINS @ 51.760% OF ACCOUNT 887.
[3] SERVICES @ 99.193% OF ACCOUNT 892.
[4] CUSTOMER-RELATED A&G @ 48.763% OF A&G (PAGE 9, LINE 38).
[5] AVERAGE ANNUAL CUSTOMER BILLS INCLUDE FINAL BILLS.

COLUMBIA GAS OF PENNSYLVANIA, INC.
CUSTOMER BASED COSTS - SYSTEM CHARGE CALCULATION WITH MAINS COMPONENT
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 15 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (I) $	MDS (J) $
1	303.30	CUSTOMER & OTHER-BASED SOFTWARE	11	12,725,296	10,713,300	1,598,170	35,631	148,631	226,001	3,563
2	376.00	MAINS [1]	20	420,210,329	348,106,438	53,475,966	1,407,705	6,319,963	10,900,256	-
3	376.00	DIRECT - MAINS [1]		51,181	-	-	-	-	-	51,181
4	376.08	MAINS-CSL REPLACEMENTS [1]	20	11,935,768	9,887,709	1,518,946	39,985	179,514	309,614	-
5	376.30	MAINS-BARE STEEL [1]	20	38,915,142	32,237,693	4,952,341	130,366	585,284	1,009,459	-
6	376.30	DIRECT - MAINS-BARE STEEL [1]		61,341	-	-	-	-	-	61,341
7	376.80	MAINS-CAST IRON [1]	20	382,716	317,046	48,704	1,282	5,756	9,928	-
8	378.10	M & R EQUIP - GENERAL [1]	20	30,470	25,241	3,878	102	458	790	-
9	378.20	M & R EQUIP - GENERAL - REGULATING [1]	20	9,791,027	8,110,985	1,246,006	32,800	147,257	253,979	-
10	378.20	DIRECT - M & R EQUIP-GEN-REG [1]	20	610	-	-	-	-	-	610
11	380.00	SERVICES [2]	15	370,945,093	340,431,150	29,838,823	148,378	337,660	189,182	-
12	380.00	DIRECT - SERVICES [2]		37,326	-	-	-	-	-	37,326
13	380.12	CSL REPLACEMENT [2]	16	-	-	-	-	-	-	-
14	381.00	METERS	16	34,301,875	25,721,261	8,124,056	94,673	278,874	78,551	4,459
15	381.10	AUTOMATIC METER READING	16	20,548,041	15,407,948	4,866,598	56,713	167,056	47,055	2,671
16	382.00	METER INSTALLATIONS	16	36,468,816	26,596,292	8,400,434	97,894	288,361	81,224	4,611
17	383.00	HOUSE REGULATORS	16	10,741,363	8,054,411	2,543,984	29,646	87,327	24,598	1,396
18	384.00	HOUSE REG INSTALLATIONS	16	3,864,772	2,897,999	915,333	10,667	31,421	8,850	502
19	385.00	IND M&R EQUIPMENT	17	5,356,556	-	3,583,135	317,263	1,044,869	410,289	-
20	385.00	DIRECT - IND M&R EQUIPMENT		122,846	-	-	-	-	-	122,846
21	385.10	IND M&R EQUIPMENT - LG VOLUME	17	1,356,628	(0)	907,652	80,367	264,678	103,931	-
22	389-398	GENERAL PLANT [3]	11	17,284,707	14,551,822	2,170,786	48,397	201,885	306,976	4,840
23		TOTAL GROSS PLANT		994,130,905	843,059,296	124,194,813	2,531,868	10,088,896	13,960,684	295,348
24	303.30	CUSTOMER & OTHER-BASED SOFTWARE	11	4,671,864	3,933,196	586,739	13,081	54,567	82,972	1,308
25	376.00	MAINS [1]	20	62,877,579	52,088,415	8,001,801	210,640	945,679	1,631,044	0
26	376.00	DIRECT - MAINS [1]		30,022	-	-	-	-	-	30,022
27	376.08	MAINS-CSL REPLACEMENTS [1]	20	-	-	-	-	-	-	0
28	376.30	MAINS-BARE STEEL [1]	20	23,672,962	19,610,918	3,012,621	79,304	356,041	614,077	0
29	376.30	DIRECT - MAINS-BARE STEEL [1]		50,190	-	-	-	-	-	50,190
30	376.80	MAINS-CAST IRON [1]	20	6,215	5,149	791	21	93	161	0
31	378.10	M & R EQUIP - GENERAL [1]	20	-	-	-	-	-	-	0
32	378.20	M & R EQUIP - GENERAL - REGULATING [1]	20	3,344,431	2,770,560	425,612	11,204	50,300	86,755	0
33	378.20	DIRECT - M & R EQUIP-GEN-REG [1]	20	450	-	-	-	-	-	450
34	380.00	SERVICES [2]	16	100,860,024	92,563,279	8,113,180	40,344	91,783	51,439	0
35	380.00	DIRECT - SERVICES [2]		21,692	-	-	-	-	-	21,692
36	380.12	CSL REPLACEMENT [2]	15	-	-	-	-	-	-	0
37	381.00	METERS	16	14,998,136	11,246,352	3,552,159	41,395	121,935	34,346	1,950
38	381.10	AUTOMATIC METER READING	16	4,440,562	3,329,755	1,051,703	12,256	36,102	10,169	577
39	382.00	METER INSTALLATIONS	16	10,435,222	7,824,851	2,471,478	28,801	84,838	23,897	1,357
40	383.00	HOUSE REGULATORS	16	2,868,259	2,150,764	679,318	7,916	23,319	6,568	373
41	384.00	HOUSE REG INSTALLATIONS	16	2,788,621	2,091,048	660,457	7,697	22,672	6,386	363
42	385.00	IND M&R EQUIPMENT	17	3,181,978	-	2,128,902	188,500	620,804	243,771	0
43	385.00	DIRECT - IND M&R EQUIPMENT		44,342	-	-	-	-	-	44,342
44	385.10	IND M&R EQUIPMENT - LG VOLUME	17	73,950	0	49,476	4,381	14,428	5,665	0
45	389-398	GENERAL PLANT [3]	11	10,694,731	9,003,788	1,343,151	29,945	124,915	189,938	2,995
46		TOTAL DEPRECIATION RESERVE		245,061,230	206,618,074	32,077,389	675,486	2,547,475	2,987,188	155,618
47	154.00	CUSTOMER BASED MATERIALS & SUPPLIES		448,316	360,274	55,998	1,138	4,528	6,244	133
48	190-282-283	CUSTOMER BASED DEFFERED INCOME TAXES		(134,612,419)	(114,156,245)	(16,816,864)	(342,833)	(1,366,108)	(1,890,376)	(39,992)
49	235.00	CUSTOMER DEPOSITS	9	(2,671,287)	(2,044,844)	(626,444)	-	-	-	-
50	252.00	CUSTOMER BASED ADVANCES		(147,067)	(124,746)	(18,370)	(373)	(1,485)	(2,048)	(44)
51	TOTAL CUSTOMER-BASED RATE BASE			612,087,219	520,495,661	74,711,745	1,514,314	6,178,355	9,087,315	99,828
52	EQUITY CAPITAL @ 52.320%			320,244,033	272,323,330	39,089,185	792,289	3,232,515	4,754,483	52,230
53	RETURN ON RATE BASE @ 8.520%			52,149,831	44,346,230	6,365,441	129,020	526,396	774,239	8,505
54	RETURN ON EQUITY @ 11.250%			36,054	30,636,375	4,397,533	89,133	363,658	534,879	5,876

COLUMBIA GAS OF PENNSYLVANIA, INC.
CUSTOMER BASED COSTS - SYSTEM CHARGE CALCULATION WITH MAINS COMPONENT
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 16 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (I) $	MDS (J) $
1	303.30	CUSTOMER & OTHER-BASED SOFTWARE	11	1,756,935	1,479,146	220,653	4,919	20,521	31,203	492
2	376.00	MAINS [1]	20	8,610,539	7,133,057	1,095,777	28,845	129,503	223,357	-
3	376.00	DIRECT - MAINS [1]		850	-	-	-	-	-	850
4	376.08	MAINS-CSL REPLACEMENTS [1]	20	-	-	-	-	-	-	-
5	376.30	MAINS-BARE STEEL [1]	20	893,020	739,787	113,646	2,992	13,431	23,165	-
6	376.30	DIRECT - MAINS-BARE STEEL [1]		1,294	-	-	-	-	-	1,294
7	376.80	MAINS-CAST IRON [1]	20	212	175	27	1	3	5	-
8	378.10	M & R EQUIP - GENERAL [1]	20	-	-	-	-	-	-	-
9	378.20	M & R EQUIP - GENERAL - REGULATING [1]	20	291,785	241,701	37,130	977	4,388	7,568	-
10	378.20	DIRECT - M & R EQUIP-GEN-REG [1]	20	15	-	-	-	-	-	15
11	380.00	SERVICES [2]	15	10,226,751	9,385,499	822,640	4,091	9,306	5,216	-
12	380.00	DIRECT - SERVICES [2]		956	-	-	-	-	-	956
13	380.12	CSL REPLACEMENT [2]	15	-	-	-	-	-	-	-
14	381.00	METERS	16	835,931	626,823	197,982	2,307	6,796	1,914	109
15	381.10	AUTOMATIC METER READING	16	1,778,260	1,333,428	421,163	4,908	14,457	4,072	231
16	382.00	METER INSTALLATIONS	16	707,167	530,269	167,486	1,952	5,749	1,619	92
17	383.00	HOUSE REGULATORS	16	284,993	213,702	67,498	787	2,317	653	37
18	384.00	HOUSE REG INSTALLATIONS	16	72,465	54,338	17,163	200	589	166	9
19	385.00	IND M&R EQUIPMENT	17	245,096	-	163,982	14,520	47,818	18,777	-
20	385.00	DIRECT - IND M&R EQUIPMENT		4,644	-	-	-	-	-	4,644
21	385.10	IND M&R EQUIPMENT - LG VOLUME	17	4,212	-	2,818	250	822	323	-
22	*389-398*	*GENERAL PLANT [3]*	11	971,390	817,803	121,997	2,720	11,346	17,252	272
23		TOTAL DEPRECIATION EXPENSES		26,686,494	22,555,728	3,449,961	69,468	267,047	335,291	9,000
24		TOTAL NET SALVAGE AMORTIZED [3]	11	3,273,841	2,756,214	411,162	9,167	38,238	58,143	917
25		TOTAL DEPRECIATION & AMORTIZATION EXPENSES		29,960,335	25,311,942	3,861,122	78,634	305,285	393,434	9,917

[1] MAINS AND RELATED @ 51.760% OF GROSS PLANT, DEPRECIATION RESERVE, & DEPRECIATION EXPENSES.
[2] SERVICES @ 99.193% OF GROSS PLANT, DEPRECIATION RESERVE, & DEPRECIATION EXPENSES.
[3] GENERAL PLANT & NET SALVAGE @ 67.303% OF GROSS PLANT, DEPRECIATION RESERVE, & DEPRECIATION EXPENSES.

COLUMBIA GAS OF PENNSYLVANIA, INC.
CUSTOMER BASED COSTS - SYSTEM CHARGE CALCULATION EXCLUDING MAINS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

EXHIBIT JES-1R
PAGE 17 OF 18
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D)	RS/RDS (E)	SGS/SGDS (F)	LGS (G)	SDS (H)	LDS (I)	MDS (J)
				$	$	$	$	$	$	$
1	874.00	MAINS & SERVICES [SERVICES ONLY][1]	15	3,137,845	2,879,726	252,408	1,255	2,856	1,600	-
2	876.00	M & R - INDUSTRIAL	17	245,982	-	164,574	14,572	47,991	18,845	-
3	878.00	METERS & HOUSE REGULATORS	16	2,455,745	1,841,440	581,619	6,778	19,965	5,624	319
4	879.00	CUSTOMER INSTALLATIONS	16	4,813,089	3,609,095	1,139,932	13,284	39,130	11,022	626
5	890.00	M & R - INDUSTRIAL	17	127,109	-	85,042	7,530	24,799	9,738	-
6	892.00	SERVICES [2]	15	2,984,103	2,738,631	240,041	1,194	2,716	1,522	-
7	893.00	METERS & HOUSE REGULATORS	16	286,063	214,504	67,751	790	2,326	655	37
8		TOTAL DISTRIBUTION		14,049,936	11,283,396	2,531,368	45,402	139,782	49,005	982
9	901.00	SUPERVISION	6	-	-	-	-	-	-	-
10	902.00	METER READING	6	2,126,147	1,936,920	186,187	404	2,126	468	43
11	903.00	COLLECTING-DELINQUENT ACCTS	6	1,072,108	976,690	93,885	204	1,072	236	21
12	903.00	COLLECTING-CURRENT ACCTS	6	7,959	7,251	697	2	8	2	0
13	903.00	BILLING & ACCOUNTING	6	5,797,611	5,281,623	507,697	1,102	5,798	1,275	116
14	903.00	RENDERING BILLS	6	2,484,720	2,263,580	217,587	472	2,485	547	50
15	904.00	UNCOLLECTIBLES-DIS REVENUE	7	3,037,943	2,601,391	415,165	3,949	7,139	9,509	790
16	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	7	38,961	33,362	5,324	51	92	122	10
17	905.00	MISCELLANEOUS	6	17,448	15,895	1,528	3	17	4	0
18	921.00	OFFICE SUPPLIES & EXPENSES	6	4,212	3,837	369	1	4	1	0
19		TOTAL CUSTOMER ACCOUNTS		14,587,109	13,120,550	1,428,438	6,187	18,741	12,163	1,030
20	907.00	SUPERVISION	6	-	-	-	-	-	-	-
21	908.00	CUSTOMER ASSISTANCE	6	613,463	558,877	53,721	117	614	135	-
22	909.00	INFORMATIONAL & INSTRUCTIONAL EXPENSES	6	38,185	34,786	3,344	7	38	8	1
23	910.00	MISCELLANEOUS	6	600,792	547,321	52,611	114	601	132	12
24	910.00	LARGE CUSTOMER RELATIONS	21	986,406	-	113,091	12,567	245,033	552,890	62,824
25	921.00	OFFICE SUPPLIES & EXPENSES	6	9,085	8,276	796	2	9	2	0
26	931.00	RENTS - GENERAL	6	140	128	12	0	0	0	0
27		TOTAL CUST SERVICE & INFORMATION		2,248,070	1,149,388	223,575	12,807	246,295	553,168	62,837
28	912.00	DEMONSTRATION	6	650,917	592,985	57,001	124	651	143	13
29	913.00	ADVERTISING	6	128,865	117,396	11,285	25	129	28	3
30		TOTAL SALES		779,782	710,381	68,285	148	780	172	16
31		CUSTOMER-RELATED BENEFITS	24	3,715,749	3,032,497	565,760	12,596	46,521	57,185	1,189
32	TOTAL CUST-RELATED O&M [LINES 8, 19, 27, 30 & 31]			35,380,645	29,296,212	4,817,427	77,140	452,119	671,693	66,054
33	DEPRECIATION EXPENSE [PAGE 2, LINE 42]			17,577,947	15,021,194	2,289,931	38,582	127,771	93,434	7,034
34	INCOME TAXES			11,749,853	10,292,794	1,362,824	17,060	50,947	22,808	3,400
35	RETURN ON RATE BASE [PAGE 2, LINE 25]			23,981,471	21,007,612	2,781,526	34,860	103,982	46,552	6,940
36		TOTAL ANNUAL CUSTOMER-BASED COST		88,689,915	75,617,812	11,251,707	167,662	734,819	834,487	83,428
37		AVERAGE ANNUAL CUSTOMER BILLS [3]		5,050,351	4,603,511	439,658	945	5,028	1,101	108
38		MONTHLY CUSTOMER BASED COST/BILL [LINE 36 / LINE 37]		$ 17.56	$ 16.43	$ 25.59	$ 177.42	$ 146.15	$ 757.94	$ 772.48

[1] MAINS AND SERVICES @ 28.872% OF TOTAL ACCOUNT 874.
[2] SERVICES @ 99.193% OF ACCOUNT 892.
[3] AVERAGE ANNUAL CUSTOMER BILLS INCLUDE FINAL BILLS.

COLUMBIA GAS OF PENNSYLVANIA, INC.
CUSTOMER BASED COSTS - SYSTEM CHARGE CALCULATION EXCLUDING MAINS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND - CORRECTED

LINE NO.	ACCT NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (I) $	MDS (J) $
1	303.30	CUSTOMER & OTHER-BASED SOFTWARE	11	12,725,296	10,713,300	1,598,170	35,631	148,631	226,001	3,563
2	380.00	SERVICES [1]	15	370,945,093	340,431,150	29,838,823	148,378	337,560	189,182	-
3	380.00	DIRECT - SERVICES [1]		37,326	-	-	-	-	-	37,326
4	380.12	CSL REPLACEMENT [1]	15	-	-	-	-	-	-	-
5	381.00	METERS	16	34,301,875	25,721,261	8,124,056	94,673	278,874	78,551	4,459
6	381.10	AUTOMATIC METER READING	16	20,548,041	15,407,948	4,866,598	56,713	167,056	47,055	2,671
7	382.00	METER INSTALLATIONS	16	35,468,816	26,596,292	8,400,434	97,894	288,361	81,224	4,611
8	383.00	HOUSE REGULATORS	16	10,741,363	8,054,411	2,543,984	29,646	87,327	24,598	1,396
9	384.00	HOUSE REG INSTALLATIONS	16	3,864,772	2,897,999	915,333	10,667	31,421	8,850	502
10	385.00	IND M&R EQUIPMENT	17	5,355,556	-	3,583,135	317,263	1,044,869	410,289	-
11	385.00	DIRECT - IND M&R EQUIPMENT		122,846	-	-	-	-	-	122,846
12	385.10	IND M&R EQUIPMENT - LG VOLUME	17	1,356,628	-	907,652	80,367	264,678	103,931	-
13		TOTAL GROSS PLANT		495,467,613	429,822,361	60,778,185	871,231	2,648,778	1,169,682	177,376
14	303.30	CUSTOMER & OTHER-BASED SOFTWARE	11	4,671,864	3,933,196	586,739	13,081	54,567	82,972	1,308
15	380.00	SERVICES [1]	15	100,860,024	92,563,279	8,113,180	40,344	91,783	51,439	-
16	380.00	DIRECT - SERVICES [1]		21,692	-	-	-	-	-	21,692
17	380.12	CSL REPLACEMENT [1]	15	-	-	-	-	-	-	-
18	381.00	METERS	16	14,998,136	11,246,352	3,552,159	41,395	121,935	34,346	1,950
19	381.10	AUTOMATIC METER READING	16	4,440,562	3,329,755	1,051,703	12,256	36,102	10,169	577
20	382.00	METER INSTALLATIONS	16	10,435,222	7,824,851	2,471,478	28,801	84,838	23,897	1,357
21	383.00	HOUSE REGULATORS	16	2,868,259	2,150,764	679,318	7,916	23,319	6,568	373
22	384.00	HOUSE REG INSTALLATIONS	16	2,768,621	2,091,048	660,457	7,697	22,672	6,386	363
23	385.00	IND M&R EQUIPMENT	17	3,181,978	-	2,128,902	188,500	620,804	243,771	-
24	385.00	DIRECT - IND M&R EQUIPMENT		44,342	-	-	-	-	-	44,342
25	385.10	IND M&R EQUIPMENT - LG VOLUME	17	73,950	-	49,476	4,381	14,428	5,665	-
26		TOTAL DEPRECIATION RESERVE		144,384,650	123,139,245	19,293,413	344,371	1,070,447	465,213	71,961
27	154.00	CUSTOMER BASED MATERIALS & SUPPLIES		224,475	194,886	27,519	389	1,163	439	81
28	190-282-283	CUSTOMER BASED DEFFERED INCOME TAXES		(67,089,851)	(58,201,015)	(8,229,800)	(117,971)	(358,663)	(158,383)	(24,018)
29	235.00	CUSTOMER DEPOSITS	9	(2,671,287)	(2,044,844)	(626,444)	-	-	-	-
30	252.00	CUSTOMER BASED ADVANCES		(73,637)	(63,931)	(9,027)	(127)	(381)	(144)	(27)
31	TOTAL CUSTOMER-BASED RATE BASE			281,472,863	248,568,213	32,647,020	409,150	1,220,449	546,380	81,451
32	EQUITY CAPITAL @ 52.320%			147,266,498	129,004,489	17,080,921	214,067	638,539	285,866	42,615
33	RETURN ON RATE BASE @ 8.520%			23,981,471	21,007,612	2,781,526	34,860	103,982	46,552	6,940
34	RETURN ON EQUITY @ 11.250%			16,567,481	14,513,005	1,921,604	24,083	71,836	32,160	4,794
35	303.30	CUSTOMER & OTHER-BASED SOFTWARE	11	1,756,935	1,479,146	220,653	4,919	20,521	31,203	492
36	380.00	SERVICES [1]	15	10,226,751	9,386,499	822,640	4,091	9,306	5,216	-
37	380.00	DIRECT - SERVICES [1]		956	-	-	-	-	-	956
38	380.12	CSL REPLACEMENT [1]	15	-	-	-	-	-	-	-
39	381.00	METERS	16	835,931	626,823	197,982	2,307	6,796	1,914	109
40	381.10	AUTOMATIC METER READING	16	1,778,260	1,333,428	421,163	4,908	14,457	4,072	231
41	382.00	METER INSTALLATIONS	16	707,167	530,269	167,485	1,962	5,749	1,619	92
42	383.00	HOUSE REGULATORS	16	284,993	213,702	67,498	787	2,317	653	37
43	384.00	HOUSE REG INSTALLATIONS	16	72,485	54,338	17,163	200	589	166	9
44	385.00	IND M&R EQUIPMENT	17	245,096	-	163,982	14,520	47,818	18,777	-
45	385.00	DIRECT - IND M&R EQUIPMENT		4,644	-	-	-	-	-	4,644
46	385.10	IND M&R EQUIPMENT - LG VOLUME	17	4,212	-	2,818	250	822	323	-
47		TOTAL DEPRECIATION EXPENSES		15,917,410	13,623,205	2,081,384	33,933	108,376	63,943	6,569
48		TOTAL NET SALVAGE AMORTIZED [2]	11	1,660,537	1,397,989	208,547	4,650	19,395	29,491	465
49	TOTAL DEPRECIATION & AMORTIZATION EXPENSES			17,577,947	15,021,194	2,289,931	38,582	127,771	93,434	7,034

[1] SERVICES @ 99.193% OF GROSS PLANT, DEPRECIATION RESERVE, & DEPRECIATION EXPENSES.

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - PROFORMA @ PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 1 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
1	TOTAL REVENUE [PAGE 6]		456,618,492	336,116,349	89,827,147	6,171,451	10,117,210	12,882,795	1,503,541
2	PRODUCTS PURCHASED [PAGE 7]		149,947,002	108,320,476	37,601,396	4,025,130	-	-	251,625
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		138,880,661	105,051,301	23,647,914	623,903	3,140,576	6,274,612	142,356
4	DEPRECIATION & AMORTIZATION [PAGE 5]		41,961,336	29,944,958	8,171,008	213,198	1,170,554	2,448,749	12,870
5	TAXES OTHER THAN INCOME [PAGE 9]		3,688,203	2,631,530	742,751	19,078	98,508	194,604	1,732
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		334,477,202	245,948,265	70,163,068	4,881,309	4,409,637	8,917,965	408,583
7	OPERATING INCOME BEFORE TAXES		121,889,665	90,168,085	19,664,078	1,290,142	5,707,572	3,964,830	1,094,958
8	INCOME TAXES		36,054,400	27,276,237	5,214,516	442,852	1,944,952	725,043	450,799
9	INVESTMENT TAX CREDIT	12	(360,239)	(252,009)	(71,987)	(1,927)	(10,868)	(23,347)	(101)
10	NET INCOME TAXES		35,694,161	27,024,228	5,142,529	440,925	1,934,084	701,696	450,698
11	OPERATING INCOME		86,195,504	63,143,857	14,521,549	849,217	3,773,488	3,263,134	644,259
12	RATE BASE [PAGE 10]		1,011,680,660	705,781,802	206,094,341	6,766,939	29,165,628	63,637,166	234,783
13	RATE OF RETURN EARNED ON RATE BASE		8.520%	8.947%	7.046%	12.550%	12.938%	5.128%	274.406%
14	UNITIZED RETURN		1.00	1.05	0.83	1.47	1.52	0.60	32.21

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - CURRENT @ CURRENT RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 2 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
1	TOTAL REVENUE [PAGE 6]		379,306,896	274,336,651	75,471,197	5,589,360	9,535,522	12,871,784	1,502,383
2	PRODUCTS PURCHASED [PAGE 7]		150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		137,753,458	104,150,553	23,438,604	615,416	3,132,095	6,274,451	142,340
4	DEPRECIATION & AMORTIZATION [PAGE 5]		41,961,336	29,944,958	8,171,008	213,198	1,170,554	2,448,749	12,870
5	TAXES OTHER THAN INCOME [PAGE 9]		3,688,203	2,631,530	742,751	19,078	98,508	194,604	1,732
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		333,601,624	245,047,517	69,953,759	4,872,822	4,401,156	8,917,804	408,566
7	OPERATING INCOME BEFORE TAXES		45,705,272	29,289,134	5,517,438	716,538	5,134,366	3,953,980	1,093,816
8	INCOME TAXES [PAGE 11]		4,442,828	2,015,429	(655,420)	204,844	1,707,109	720,541	450,326
9	INVESTMENT TAX CREDIT	12	(360,239)	(252,009)	(71,987)	(1,927)	(10,868)	(23,347)	(101)
10	NET INCOME TAXES		4,082,589	1,763,420	(727,407)	202,917	1,696,240	697,194	450,225
11	OPERATING INCOME		41,622,683	27,525,714	6,244,845	513,622	3,438,125	3,256,785	643,591
12	RATE BASE [PAGE 10]		1,011,680,660	705,781,802	206,094,341	6,766,939	29,165,628	63,637,166	234,783
13	RATE OF RETURN EARNED ON RATE BASE		4.114%	3.900%	3.030%	7.590%	11.788%	5.118%	274.121%
14	UNITIZED RETURN		1.00	0.95	0.74	1.84	2.87	1.24	66.63

COLUMBIA GAS OF PENNSYLVANIA, INC.
GROSS PLANT (Accounts 101 & 106)
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 3 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	301-305	INTANGIBLE PLANT	11	13,197,924	9,229,836	2,636,153	69,685	399,765	858,789	3,695
2	350-362	UNDERGROUND STORAGE PLANT	25	6,014,913	4,535,605	1,342,047	128,839	-	-	8,421
		DISTRIBUTION PLANT								
3	374.10	LAND - CITY GATE & M/L IND M&R	5	188,844	115,597	45,275	1,345	8,173	18,454	-
4	374.20	LAND - OTHER DISTRIBUTION	5	480,964	294,412	115,311	3,425	20,816	47,000	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	5	95,361	58,373	22,863	679	4,127	9,319	-
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	5	1,783,038	1,091,451	427,483	12,695	77,170	174,239	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		3	-	-	-	-	-	3
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	5	13	9	3	-	-	1	-
9	374.50	RIGHTS OF WAY	5	3,231,844	1,978,308	774,835	23,011	139,874	315,816	-
10	374.50	DIRECT - RIGHTS OF WAY		1,195	-	-	-	-	-	1,195
11	375.20	M & R STRUCTURES - CITY GATE	5	813,126	497,739	194,947	5,790	35,192	79,459	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	5	4,012	2,456	962	29	174	392	-
13	375.40	M & R STRUCTURES - REGULATING	5	2,714,399	1,661,565	650,777	19,327	117,479	265,251	-
14	375.60	M & R STRUCTURES - DIST. IND. M & R	17	87,692	(0)	58,671	5,195	17,109	6,718	-
15	375.70	M & R STRUCTURES - OTHER	11	4,150,247	2,902,434	828,970	21,913	125,711	270,057	1,162
16	375.71	M & R STRUCTURES - OTHER LEASED	11	1,031,960	721,691	206,124	5,449	31,258	67,150	289
17	375.80	M & R STRUCTURES - COMMUNICATION	5	16,515	10,109	3,960	118	715	1,614	-
18	376.00	MAINS	5	811,843,757	496,953,919	194,639,541	5,780,328	35,136,598	79,333,372	-
19	376.00	DIRECT - MAINS		98,881	-	-	-	-	-	98,881
20	376.08	MAINS-CSL REPLACEMENTS	5	23,059,830	14,115,614	5,528,594	164,186	998,029	2,253,407	-
21	376.30	MAINS-BARE STEEL	5	75,183,814	46,022,268	18,025,320	535,309	3,253,956	7,346,962	-
22	376.30	DIRECT - MAINS-BARE STEEL		118,511	-	-	-	-	-	118,511
23	376.80	MAINS-CAST IRON	5	739,405	452,612	177,272	5,265	32,002	72,255	-
24	378.10	M & R EQUIP - GENERAL	5	58,867	36,035	14,114	419	2,548	5,753	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	5	18,916,204	11,579,176	4,535,160	134,683	818,693	1,848,492	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		1,178	-	-	-	-	-	1,178
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	5	486,506	297,805	116,640	3,464	21,056	47,541	-
28	379.10	M & R EQUIP - CITY GATE	5	147,820	90,485	35,440	1,053	6,398	14,445	-
29	379.11	M & R EQUIP - EXCHANGE GAS	5	5,974	3,657	1,432	43	259	584	-
30	380.00	SERVICES	15	373,962,974	343,200,780	30,081,582	149,585	340,306	190,721	-
31	380.00	DIRECT - SERVICES		37,630	-	-	-	-	-	37,630
32	380.12	CSL REPLACEMENT	15	-	-	-	-	-	-	-
33	381.00	METERS	16	34,301,875	25,721,261	8,124,056	94,673	278,874	78,551	4,459
34	381.10	AUTOMATIC METER READING	16	20,548,041	15,407,948	4,866,598	56,713	167,056	47,055	2,671
35	382.00	METER INSTALLATIONS	16	35,468,816	26,596,292	8,400,435	97,894	288,362	81,224	4,611
36	383.00	HOUSE REGULATORS	16	10,741,363	8,054,411	2,543,984	29,646	87,327	24,598	1,396
37	384.00	HOUSE REG INSTALLATIONS	16	3,864,772	2,897,999	915,333	10,667	31,421	8,850	502
38	385.00	IND M&R EQUIPMENT	17	5,355,556	-	3,583,135	317,263	1,044,869	410,289	-
39	385.00	DIRECT - IND M&R EQUIPMENT		122,846	-	-	-	-	-	122,846
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	1,356,628	-	907,852	80,367	264,678	103,931	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	16,603	11,611	3,316	88	503	1,080	5
42	387.20	OTHER EQUIP ODORIZATION	11	121,943	85,279	24,357	644	3,694	7,935	34
43	387.42	OTHER EQUIP RADIO	11	130,407	91,199	26,048	689	3,950	8,486	37
44	387.44	OTHER EQUIP COMMUNICATION	11	664,599	464,781	132,747	3,509	20,131	43,246	186
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	259,436	181,434	51,820	1,370	7,858	16,882	73
46		TOTAL DISTRIBUTION PLANT		##########	##########	286,064,754	7,566,828	43,386,364	93,201,125	395,670
47	389-398	GENERAL PLANT	11	25,681,9[illegible]	17,960,399	5,129,708	135,601	777,906	1,671,123	7,191
48	TOTAL GROSS PLANT			##########	##########	295,172,663	7,900,953	44,564,034	95,731,037	414,977

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEPRECIATION RESERVE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 4 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	301-305	INTANGIBLE PLANT	11	4,670,206	3,266,062	932,827	24,659	141,461	303,890	1,308
2	350-362	UNDERGROUND STORAGE PLANT	25	1,332,255	1,004,600	297,253	28,537	-	-	1,865
		DISTRIBUTION PLANT								
3	374.10	LAND - CITY GATE & M/L IND M&R	5	-	-	-	-	-	-	-
4	374.20	LAND - OTHER DISTRIBUTION	5	(24,311)	(14,881)	(5,829)	(173)	(1,052)	(2,376)	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	5	-	-	-	-	-	-	-
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	5	635,353	388,919	152,326	4,524	27,498	62,087	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		1	-	-	-	-	-	1
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	5	-	-	-	-	-	-	-
9	374.50	RIGHTS OF WAY	5	1,495,661	915,539	358,585	10,649	64,732	146,156	-
10	374.50	DIRECT - RIGHTS OF WAY		664	-	-	-	-	-	664
11	375.20	M & R STRUCTURES - CITY GATE	5	-	-	-	-	-	-	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	5	-	-	-	-	-	-	-
13	375.40	M & R STRUCTURES - REGULATING	5	789,197	483,091	189,210	5,619	34,156	77,120	-
14	375.60	M & R STRUCTURES - DIST. IND. M & R	17	71,206	-	47,640	4,218	13,892	5,455	-
15	375.70	M & R STRUCTURES - OTHER	11	2,143,906	1,499,319	428,224	11,320	64,939	139,504	600
16	375.71	M & R STRUCTURES - OTHER LEASED	11	971,923	679,705	194,132	5,132	29,440	63,243	272
17	375.80	M & R STRUCTURES - COMMUNICATION	5	5,681	3,478	1,362	40	246	555	-
18	376.00	MAINS	5	121,479,094	74,360,998	29,124,613	864,931	5,257,615	11,870,937	-
19	376.00	*DIRECT - MAINS*		58,002	-	-	-	-	-	58,002
20	376.08	MAINS-CSL REPLACEMENTS	5	-	-	-	-	-	-	-
21	376.30	MAINS-BARE STEEL	5	45,736,016	27,996,387	10,965,210	325,640	1,979,455	4,469,324	-
22	376.30	DIRECT - MAINS-BARE STEEL		96,966	-	-	-	-	-	96,966
23	376.80	MAINS-CAST IRON	5	12,008	7,351	2,879	86	520	1,173	-
24	378.10	M & R EQUIP - GENERAL	5	-	-	-	-	-	-	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	5	6,461,419	3,955,229	1,549,125	46,005	279,650	631,410	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		870	-	-	-	-	-	870
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	5	-	-	-	-	-	-	-
28	379.10	M & R EQUIP - CITY GATE	5	94,719	57,980	22,709	674	4,099	9,256	-
29	379.11	M & R EQUIP - EXCHANGE GAS	5	-	-	-	-	-	-	-
30	380.00	SERVICES	15	101,680,586	93,316,341	8,179,186	40,672	92,529	51,857	-
31	380.00	DIRECT - SERVICES		21,869	-	-	-	-	-	21,869
32	380.12	CSL REPLACEMENT	15	-	-	-	-	-	-	-
33	381.00	METERS	16	14,998,136	11,246,352	3,552,159	41,395	121,935	34,346	1,950
34	381.10	AUTOMATIC METER READING	16	4,440,562	3,329,755	1,051,703	12,256	36,102	10,169	577
35	382.00	METER INSTALLATIONS	16	10,435,222	7,824,851	2,471,478	28,801	84,838	23,897	1,357
36	383.00	*HOUSE REGULATORS*	16	2,868,259	2,150,764	679,319	7,916	23,319	6,568	373
37	384.00	HOUSE REG INSTALLATIONS	16	2,788,621	2,091,048	660,457	7,697	22,672	6,386	363
38	385.00	IND M&R EQUIPMENT	17	3,181,978	-	2,128,902	188,500	620,804	243,771	-
39	385.00	DIRECT - IND M&R EQUIPMENT		44,342	-	-	-	-	-	44,342
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	73,950	0	49,476	4,381	14,428	5,665	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	-	-	-	-	-	-	-
42	387.20	OTHER EQUIP ODORIZATION	11	-	-	-	-	-	-	-
43	387.42	OTHER EQUIP RADIO	11	-	-	-	-	-	-	-
44	387.44	OTHER EQUIP COMMUNICATION	11	-	-	-	-	-	-	-
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	545,616	381,571	108,981	2,881	16,527	35,503	163
46		TOTAL DISTRIBUTION PLANT		321,107,516	230,673,797	61,911,847	1,613,165	8,788,343	17,892,007	228,358
47	389-398	GENERAL PLANT	11	15,890,423	11,112,609	3,173,953	83,901	481,321	1,033,990	4,449
48	TOTAL DEPRECIATION RESERVE			343,000,400	246,057,267	66,315,879	1,750,262	9,411,125	19,229,887	235,980

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 5 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	301-305	INTANGIBLE PLANT	11	1,756,935	1,228,695	350,930	9,277	53,218	114,324	492
2	350-362	UNDERGROUND STORAGE PLANT	25	163,868	123,586	36,562	3,510	-	-	229
		DISTRIBUTION PLANT								
3	374.10	LAND - CITY GATE & M/L IND M&R	5	-	-	-	-	-	-	-
4	374.20	LAND - OTHER DISTRIBUTION	5	-	-	-	-	-	-	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	5	-	-	-	-	-	-	-
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	5	35,574	21,776	8,529	253	1,540	3,476	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		0	-	-	-	-	-	0
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	5	-	-	-	-	-	-	-
9	374.50	RIGHTS OF WAY	5	43,000	26,322	10,309	306	1,861	4,202	-
10	374.50	DIRECT - RIGHTS OF WAY		16	-	-	-	-	-	16
11	375.20	M & R STRUCTURES - CITY GATE	5	-	-	-	-	-	-	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	5	-	-	-	-	-	-	-
13	375.40	M & R STRUCTURES - REGULATING	5	81,608	49,955	19,566	581	3,532	7,975	-
14	375.60	M & R STRUCTURES - DIST. IND. M & R	17	973	0	651	58	190	75	-
15	375.70	M & R STRUCTURES - OTHER	11	161,680	113,069	32,294	854	4,897	10,521	45
16	375.71	M & R STRUCTURES - OTHER LEASED	11	182,501	127,630	36,453	964	5,528	11,875	51
17	375.80	M & R STRUCTURES - COMMUNICATION	5	342	209	82	2	15	33	-
18	376.00	MAINS	5	16,635,509	10,183,094	3,988,363	118,445	719,985	1,625,622	-
19	376.00	DIRECT - MAINS		1,641	-	-	-	-	-	1,641
20	376.08	MAINS-CSL REPLACEMENTS	5	-	-	-	-	-	-	-
21	376.30	MAINS-BARE STEEL	5	1,725,309	1,056,114	413,643	12,284	74,671	168,597	-
22	376.30	DIRECT - MAINS-BARE STEEL		2,501	-	-	-	-	-	2,501
23	376.80	MAINS-CAST IRON	5	409	250	98	3	18	40	-
24	378.10	M & R EQUIP - GENERAL	5	-	-	-	-	-	-	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	5	563,688	345,050	135,144	4,014	24,396	55,084	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		29	-	-	-	-	-	29
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	5	-	-	-	-	-	-	-
28	379.10	M & R EQUIP - CITY GATE	5	5,023	3,075	1,204	36	217	491	-
29	379.11	M & R EQUIP - EXCHANGE GAS	5	-	-	-	-	-	-	-
30	380.00	SERVICES	15	10,309,953	9,461,856	829,333	4,124	9,382	5,258	-
31	380.00	DIRECT - SERVICES		963	-	-	-	-	-	963
32	380.12	CSL REPLACEMENT	15	-	-	-	-	-	-	-
33	381.00	METERS	16	835,931	626,823	197,982	2,307	6,796	1,914	109
34	381.10	AUTOMATIC METER READING	16	1,778,260	1,333,428	421,163	4,908	14,457	4,072	231
35	382.00	METER INSTALLATIONS	16	707,167	530,269	167,485	1,952	5,749	1,619	92
36	383.00	HOUSE REGULATORS	16	284,993	213,702	67,498	787	2,317	653	37
37	384.00	HOUSE REG INSTALLATIONS	16	72,465	54,338	17,163	200	589	166	9
38	385.00	IND M&R EQUIPMENT	17	245,096	0	183,982	14,520	47,818	18,777	-
39	385.00	DIRECT - IND M&R EQUIPMENT		4,644	-	-	-	-	-	4,644
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	4,212	-	2,818	250	822	323	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	-	-	-	-	-	-	-
42	387.20	OTHER EQUIP ODORIZATION	11	-	-	-	-	-	-	-
43	387.42	OTHER EQUIP RADIO	11	-	-	-	-	-	-	-
44	387.44	OTHER EQUIP COMMUNICATION	11	-	-	-	-	-	-	-
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	49,407	34,552	9,869	261	1,497	3,215	14
46		TOTAL DISTRIBUTION PLANT		33,732,894	24,181,513	6,523,628	167,107	926,278	1,923,987	10,382
47	389-398	GENERAL PLANT	11	1,443,308	1,009,363	288,286	7,621	43,718	93,916	404
48		NET DEPRECIATION & AMORTIZATION EXPENSE		37,097,005	26,543,137	7,199,406	187,514	1,023,213	2,132,227	11,508
49		AMORTIZATION OF NET NEGATIVE SALVAGE	11	4,864,331	3,401,821	971,602	25,684	147,341	316,622	1,362
50	TOTAL AMORTIZATION AND DEPRECIATION EXPENSE			41,961,336	29,944,958	8,171,008	213,198	1,170,554	2,448,749	12,870

COLUMBIA GAS OF PENNSYLVANIA, INC.
OPERATING REVENUE @ PROPOSED & CURRENT RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 6 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
		PROPOSED OPERATING REVENUE								
		SALES REVENUE								
1	480/481	SALES BASE REVENUE		214,051,481	173,800,330	38,100,661	2,130,998	-	-	19,492
2		USP REVENUE		8,309,047	8,309,047	-	-	-	-	-
3		STAS REVENUE		-	-	-	-	-	-	-
4		UNBUNDLED UNCOLLECTIBLES REVENUE		1,848,276	1,363,655	484,621	-	-	-	-
5		*GAS PROCUREMENT REVENUE*	2	465,287	332,745	118,253	13,410	-	-	879
6		GAS COST REVENUE		141,900,550	102,129,786	35,494,009	4,025,130	-	-	251,625
7		TOTAL SALES REVENUE		366,574,641	285,935,563	74,197,544	6,169,538	-	-	271,996
		TRANSPORTATION REVENUE								
8	489.00	TRANSPORTATION BASE REVENUE		73,174,899	40,288,371	13,273,361	-	9,900,113	9,492,046	221,008
9		USP REVENUE		2,549,024	2,549,024	-	-	-	-	-
10		STAS REVENUE		-	-	-	-	-	-	-
11		FLEX REVENUE		4,613,061	-	32,146		201,904	3,369,813	1,009,198
12		GAS COST REVENUE		8,298,077	6,190,690	2,107,387	-	-	-	-
13		TOTAL TRANSPORTATION REVENUE		88,635,061	49,028,085	15,412,894	-	10,102,017	12,861,859	1,230,206
		MISCELLANEOUS REVENUE								
14	487.00	*FORFEITED DISCOUNTS*	10	*944,367*	*766,231*	*156,633*	*944*	*9,661*	*9,814*	*1,284*
15	488.00	MISCELLANEOUS REVENUE	6	146,687	133,632	12,845	28	147	32	3
16	493.00	RENTS	11	173,011	120,994	34,557	914	5,241	11,258	48
17	495.00	OTHER	6	144,725	131,845	12,674	28	145	32	3
18		TOTAL MISCELLANEOUS REVENUE		1,408,790	1,152,701	218,709	1,913	15,193	20,936	1,339
19		TOTAL PROPOSED OPERATING REVENUE		456,618,492	336,116,349	89,827,147	6,171,451	10,117,210	12,882,795	1,503,541
		CURRENT OPERATING REVENUE								
		SALES REVENUE								
20	480/481	SALES BASE REVENUE		138,032,974	112,543,257	23,906,093	1,564,132	-	-	19,492
21		USP REVENUE		8,309,047	8,309,047	-	-	-	-	-
22		STAS REVENUE		(181,366)	(151,797)	(27,731)	(1,815)	-	-	(23)
23		UNBUNDLED UNCOLLECTIBLES REVENUE		1,848,276	1,363,655	484,621	-	-	-	-
24		GAS COST REVENUE		141,900,550	102,129,786	35,494,009	4,025,130	-	-	251,625
25		TOTAL SALES REVENUE		289,909,481	224,193,948	59,856,992	5,587,447	-	-	271,094
		TRANSPORTATION REVENUE								
26	489.00	TRANSPORTATION BASE REVENUE		72,604,033	40,288,371	13,273,361	-	9,329,247	9,492,046	221,008
27		USP REVENUE		2,549,024	2,549,024	-	-	-	-	-
28		STAS REVENUE		(75,570)	(38,083)	(15,398)	-	(10,822)	(11,011)	(256)
29		FLEX REVENUE		4,613,061	-	32,146	-	201,904	3,369,813	1,009,198
30		GAS COST REVENUE		8,298,077	6,190,690	2,107,387	-	-	-	-
31		TOTAL TRANSPORTATION REVENUE		87,988,625	48,990,002	15,397,496	-	9,520,329	12,850,848	1,229,950
		MISCELLANEOUS REVENUE								
32	487.00	FORFEITED DISCOUNTS	10	944,367	766,231	156,633	944	9,661	9,814	1,284
33	488.00	MISCELLANEOUS REVENUE	6	146,687	133,632	12,845	28	147	32	3
34	493.00	RENTS	11	173,011	120,994	34,557	914	5,241	11,258	48
35	495.00	OTHER	6	144,725	131,845	12,674	28	145	32	3
36		TOTAL MISCELLANEOUS REVENUE		1,408,790	1,152,701	218,709	1,913	15,193	20,936	1,339
37		TOTAL CURRENT OPERATING REVENUE		379,306,896	274,336,651	75,471,197	5,589,360	9,535,522	12,871,784	1,502,383

COLUMBIA GAS OF PENNSYLVANIA, INC.
PRODUCTION & DISTRIBUTION O&M EXPENSES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 7 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
		PURCHASED GAS EXPENSES								
1		GAS PURCHASED COST		149,947,002	108,320,476	37,601,396	4,025,130	-	-	251,625
2	807.00	PURCHASED GAS EXPENSE	4	1,036,138	747,242	259,387	27,769	-	-	1,741
3	807.00	GAS PROCUREMENT EXPENSE	4	465,287	335,556	116,480	12,470	-	-	782
4		TOTAL PURCHASED GAS		151,448,427	109,403,274	37,977,263	4,065,368	-	-	254,147
		UNDERGROUND STORAGE OPERATIONS EXPENSES								
5	816.00	WELLS	25	10,754	8,109	2,399	230	-	-	15
6	817.00	LINES	25	37,625	28,371	8,395	806	-	-	53
7	818.00	COMPRESSOR STATION	25	150,458	113,455	33,570	3,223	-	-	211
8	820.00	M & R	25	15,840	11,944	3,534	339	-	-	22
9	821.00	PURIFICATION	25	3,082	2,324	688	66	-	-	4
10	823.00	GAS LOSSES	25	2,052	1,547	458	44	-	-	3
11	825.00	STORAGE WELL ROYALTIES	25	5,977	4,507	1,334	128	-	-	8
12		TOTAL UNDERGROUND STORAGE OPERATIONS		225,787	170,257	50,378	4,836	-	-	318
		UNDERGROUND STORAGE MAINTENANCE EXPENSES								
13	832.00	WELLS	25	7,823	5,899	1,745	168	-	-	11
14	834.00	COMPRESSOR STATION	25	6,230	4,698	1,390	134	-	-	9
15	836.00	PURIFICATION	25	6,789	5,120	1,515	145	-	-	10
16		TOTAL UNDERGROUND STORAGE MAINTENANCE		20,843	15,717	4,650	447	-	-	29
17		TOTAL UNDERGROUND STORAGE		246,630	185,974	55,028	5,283	-	-	345
		DISTRIBUTION OPERATIONS EXPENSES								
18	870.00	SUPERVISION & ENGINEERING	18	4,666,895	3,233,598	1,000,582	25,528	136,180	270,167	840
19	871.00	LOAD DISPATCHING	13	124,644	76,280	29,876	888	5,393	12,178	30
20	874.00	MAINS & SERVICES	14	10,868,086	7,617,985	2,101,236	56,079	336,259	754,354	2,174
21	875.00	M & R - GENERAL	13	590,194	361,187	141,464	4,202	25,538	57,662	142
22	876.00	M & R - INDUSTRIAL	17	245,982	-	164,574	14,572	47,991	18,845	-
23	878.00	METERS & HOUSE REGULATORS	16	2,455,745	1,841,440	581,619	6,778	19,965	5,624	319
24	879.00	CUSTOMER INSTALLATIONS	16	4,813,089	3,609,095	1,139,932	13,284	39,130	11,022	626
25	880.00	OTHER	18	4,881,051	3,381,983	1,046,497	26,699	142,429	282,564	879
26	881.00	RENTS	18	273,398	189,432	58,617	1,496	7,978	15,827	49
27		TOTAL DISTRIBUTION OPERATIONS		28,919,083	20,310,999	6,264,396	149,526	760,863	1,428,241	5,058
		DISTRIBUTION MAINTENANCE EXPENSES								
28	885.00	SUPERVISION & ENGINEERING	18	51,399	35,613	11,020	281	1,500	2,976	9
29	886.00	STRUCTURES AND IMPROVEMENTS	13	52,374	32,052	12,554	373	2,266	5,117	13
30	887.00	MAINS	13	10,193,632	6,238,299	2,443,312	72,579	441,079	995,918	2,447
31	889.00	M & R - GENERAL	13	609,190	372,806	146,014	4,337	26,359	59,517	146
32	890.00	M & R - INDUSTRIAL	17	127,109	-	85,042	7,530	24,799	9,738	-
33	892.00	SERVICES	15	3,008,381	2,760,911	241,994	1,203	2,738	1,534	-
34	893.00	METERS & HOUSE REGULATORS	16	286,063	214,505	67,751	790	2,326	655	37
35	894.00	OTHER EQUIPMENT	18	796,193	551,666	170,704	4,355	23,233	46,092	143
36		TOTAL DISTRIBUTION MAINTENANCE		15,124,330	10,205,851	3,178,391	91,448	524,299	1,121,546	2,795
37		TOTAL DISTRIBUTION		44,043,414	30,516,851	9,442,787	240,974	1,285,162	2,549,787	7,853

COLUMBIA GAS OF PENNSYLVANIA, INC.
OTHER O&M EXPENSES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 8 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
		CUSTOMER ACCOUNTS EXPENSES								
1	901.00	SUPERVISION	6	-	-	-	-	-	-	-
2	902.00	METER READING	6	2,126,147	1,936,920	186,187	404	2,126	468	43
3	903.00	COLLECTING-DELINQUENT ACCTS	6	1,072,108	976,690	93,885	204	1,072	236	21
4	903.00	COLLECTING-CURRENT ACCTS	6	7,959	7,251	697	2	8	2	0
5	903.00	BILLING & ACCOUNTING	6	5,797,611	5,281,623	507,697	1,102	5,798	1,276	116
6	903.00	RENDERING BILLS	6	2,484,720	2,263,580	217,587	472	2,485	547	50
7	904.00	UNCOLLECTIBLES-DIS REVENUE	7	3,037,943	2,601,391	415,165	3,949	7,139	9,509	790
8	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	7	38,961	33,362	5,324	51	92	122	10
9	904.00	UNCOLLECTIBLES-UNBUNDLED GAS	23	1,848,276	1,593,898	254,378	-	-	-	-
10	904.00	DIRECT USP UNCOLLECTIBLES		8,469,295	8,469,295	-	-	-	-	-
11	905.00	MISCELLANEOUS	6	17,448	15,895	1,528	3	17	4	0
12	921.00	OFFICE SUPPLIES & EXPENSES	6	4,212	3,837	369	1	4	1	-
13		TOTAL CUSTOMER ACCOUNTS		24,904,680	23,183,743	1,682,817	6,187	18,741	12,163	1,030
		CUST SERVICE & INFORMATION EXPENSES								
14	907.00	SUPERVISION	6	-	-	-	-	-	-	-
15	908.00	CUSTOMER ASSISTANCE	6	613,463	558,877	53,721	117	614	135	-
16	908.00	DIRECT USP/LIURP/HEEP		2,388,776	2,388,776	-	-	-	-	-
17	909.00	INFORMATIONAL & INSTRUCTIONAL EXPENSES	6	38,185	34,786	3,344	7	38	8	1
18	910.00	MISCELLANEOUS	6	600,792	547,321	52,611	114	601	132	12
19	910.00	LARGE CUSTOMER RELATIONS	21	986,406	0	113,091	12,567	245,033	552,890	62,824
20	921.00	OFFICE SUPPLIES & EXPENSES	6	9,085	8,277	796	2	9	2	-
21	931.00	RENTS - GENERAL	6	140	128	12	-	-	-	-
22		TOTAL CUST SERVICE & INFORMATION		4,636,846	3,538,165	223,575	12,807	246,295	553,168	62,837
		SALES EXPENSES								
23	912.00	DEMONSTRATION	6	650,917	592,985	57,001	124	651	143	13
24	913.00	ADVERTISING	6	128,865	117,396	11,285	25	129	28	3
25		TOTAL SALES		779,782	710,381	68,286	148	780	172	16
		ADMINISTRATIVE AND GENERAL EXPENSES								
26	920.00	SALARIES	19	3,908,071	2,858,754	723,814	19,540	100,008	201,188	4,768
27	921.00	OFFICE SUPPLIES & EXPENSES	19	2,016,774	1,475,270	373,527	10,084	51,609	103,824	2,461
28	922.00	ADMIN. EXPENSE TRANSFERRED	19	-	-	-	-	-	-	-
29	923.00	OUTSIDE SERVICES EMPLOYED	19	41,245,654	30,171,196	7,639,108	206,228	1,055,476	2,123,326	50,320
30	924.00	PROPERTY INSURANCE	19	157,493	115,206	29,169	788	4,030	8,108	192
31	925.00	INJURIES AND DAMAGES	19	3,725,912	2,725,505	690,076	18,630	95,346	191,810	4,546
32	926.00	EMPLOYEE PENSIONS & BENEFITS	24	8,294,725	5,910,074	1,710,041	43,050	215,995	412,911	2,654
33	928.00	REGULATORY COMMISSION EXPENSES	19	1,428,131	1,044,678	264,504	7,141	36,546	73,520	1,742
34	930.00	MISCELLANEOUS GENERAL	19	568,725	416,022	105,334	2,844	14,554	29,278	694
35	931.00	RENTS-GENERAL	19	295,199	215,938	54,674	1,476	7,554	15,197	360
36		TOTAL ADMINISTRATIVE & GENERAL		61,640,682	44,932,642	11,590,245	309,780	1,581,118	3,159,161	67,736
37		TOTAL O & M EXPENSES		287,700,461	212,471,029	61,040,000	4,640,546	3,132,095	6,274,451	393,965

COLUMBIA GAS OF PENNSYLVANIA, INC.
TAXES OTHER THAN INCOME TAXES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 9 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D)	RS/RDS (E)	SGS/SGDS (F)	LGS (G)	SDS (H)	LDS (I)	MDS (J)
		FEDERAL TAXES		$	$	$	$	$	$	$
1	408.00	FEDERAL UNEMPLOYMENT	24	45,196	32,203	9,318	235	1,177	2,250	15
2	408.00	FICA	24	2,190,869	1,561,016	451,670	11,371	57,050	109,062	701
3		TOTAL FEDERAL TAXES		2,236,065	1,593,219	460,987	11,605	58,227	111,311	716
		STATE TAXES								
4	408.00	PA PROPERTY TAXES	11	642,142	449,075	128,261	3,391	19,451	41,784	180
5	408.00	PA STATE UNEMPLOYMENT	24	161,920	115,370	33,381	840	4,216	8,060	52
6	408.00	STATE CAPITAL STOCK TAX	11	-	-	-	-	-	-	-
7	408.00	LICENSE AND FRANCHISE TAX	11	6,251	4,372	1,249	33	189	407	2
8	408.00	STATE SALES AND USE TAX	19	614,394	449,429	113,792	3,072	15,722	31,629	750
9	408.00	OTHER	19	27,431	20,066	5,081	137	702	1,412	34
10		TOTAL STATE TAXES		1,452,138	1,038,311	281,764	7,473	40,281	83,293	1,017
11		TOTAL TAXES OTHER THAN INCOME		3,688,203	2,631,530	742,751	19,078	98,508	194,604	1,732

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE BASE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 10 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	101-107	GROSS PLANT [PAGE 3]		1,477,108,215	1,033,324,551	295,172,663	7,900,953	44,564,034	95,731,037	414,977
2	117.00	GAS STORED UNDERGROUND - NON CURRENT	25	3,794,990	2,861,650	846,738	81,289	-	-	5,313
3	108-111	DEPRECIATION RESERVE [PAGE 4]		(343,000,400)	(246,057,267)	(66,315,879)	(1,750,262)	(9,411,125)	(19,229,887)	(235,980)
4	117.00	GAS LOST-UNDERGROUND STORAGE	1	(163,458)	(99,739)	(37,756)	(1,944)	(8,717)	(15,303)	-
5		NET PLANT		1,137,739,347	790,029,195	229,665,766	6,230,036	35,144,193	76,485,847	184,310
		WORKING CAPITAL								
6	154.00	MATERIALS & SUPPLIES	11	663,015	463,673	132,431	3,501	20,083	43,142	186
7	164.00	GAS STORED UNDERGROUND - FSS	25	74,526,147	56,197,186	16,628,274	1,596,350	-	-	104,337
8	165.00	PREPAYMENTS	19	1,651,928	1,208,385	305,954	8,260	42,273	85,041	2,015
9		CASH WORKING CAPITAL - GAS PURCHASES	4	-	-	-	-	-	-	-
10		CASH WORKING CAPITAL - ALL OTHER	19	-	-	-	-	-	-	-
11		TOTAL WORKING CAPITAL		76,841,090	57,869,245	17,066,658	1,608,110	62,356	128,184	106,538
		DEFERRED INCOME TAXES								
12	190.00	ACCUMULATED DEF INCOME TAX	12	3,351,427	2,344,524	669,716	17,930	101,113	217,206	938
13	282.00	ACCUMULATED DEF INCOME TAX	12	(203,338,966)	(142,247,807)	(40,633,226)	(1,087,864)	(6,134,737)	(13,178,398)	(56,935)
14	283.00	ACCUMULATED DEF INCOME TAX	12	(23,454)	(16,407)	(4,687)	(126)	(708)	(1,520)	(7)
15		TOTAL DEFERRED INCOME TAXES		(200,010,993)	(139,919,690)	(39,968,197)	(1,070,059)	(6,034,332)	(12,962,713)	(56,003)
16	235.00	CUSTOMER DEPOSITS	9	(2,671,287)	(2,044,844)	(626,444)	-	-	-	-
17	252.00	CUSTOMER ADVANCES	11	(217,497)	(152,104)	(43,443)	(1,148)	(6,588)	(14,153)	(61)
18		RATE BASE		1,011,680,660	705,781,802	206,094,341	6,766,939	29,165,628	63,637,166	234,783

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATE/FEDERAL INCOME TAXES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 11 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
	STATE INCOME TAX								
1	OPERATING INCOME BEFORE TAXES (PG. 2, LINE 8)		45,705,272	29,289,134	5,517,438	716,538	5,134,366	3,953,980	1,093,816
2	STATUTORY ADJUSTMENTS	12	(37,630,943)	(26,325,102)	(7,519,791)	(201,326)	(1,135,326)	(2,438,861)	(10,537)
3	INTEREST ON DEBT		(26,607,201)	(18,562,061)	(5,420,281)	(177,971)	(767,056)	(1,673,657)	(6,175)
4	PA BONUS DEPRECIATION ADJUSTMENT	12	(5,114,711)	(3,578,047)	(1,022,073)	(27,364)	(154,311)	(331,484)	(1,432)
5	STATE TAXABLE INCOME		(23,647,583)	(19,176,077)	(8,444,707)	309,879	3,077,673	(490,024)	1,075,673
6	NET OPERATING LOSS DEDUCTION	12	-	-	-	-	-	-	-
	STATE TAXABLE INCOME		(23,647,583)	(19,176,077)	(8,444,707)	309,879	3,077,673	(490,024)	1,075,673
7	STATE NET INCOME TAX @ 9.99%		(2,362,394)	(1,915,690)	(843,626)	30,957	307,460	(48,953)	107,460
8	DEFERRED INCOME TAXES	12	1,566,210	1,095,658	312,976	8,379	47,253	101,506	439
9	STATE INCOME TAX		(796,184)	(820,032)	(530,651)	39,336	354,712	52,553	107,898
	FEDERAL INCOME TAX								
10	OPERATING INCOME BEFORE TAXES (PG. 2, LINE 8)		45,705,272	29,289,134	5,517,438	716,538	5,134,366	3,953,980	1,093,816
11	STATE NET INCOME TAX (LINE 7)		2,362,394	1,915,690	843,626	(30,957)	(307,460)	48,953	(107,460)
12	STATUTORY ADJUSTMENTS (LINES 2 & 3)	12	(64,238,144)	(44,887,164)	(12,940,072)	(379,296)	(1,902,382)	(4,112,519)	(16,712)
13	FEDERAL TAXABLE INCOME		(16,170,478)	(13,682,339)	(6,579,008)	306,285	2,924,524	(109,586)	969,645
14	FEDERAL INCOME TAX @ 35%		(5,659,667)	(4,788,819)	(2,302,653)	107,200	1,023,584	(38,355)	339,376
15	DEFERRED INCOME TAXES	12	16,164,641	11,308,136	3,230,180	86,481	487,687	1,047,630	4,526
16	TAX REFUND AMORTIZATION	12	(4,089,420)	(2,860,795)	(817,189)	(21,878)	(123,378)	(265,035)	(1,145)
17	FLOW BACK OF EXCESS DEFERRED TAXES	12	(628,368)	(439,581)	(125,567)	(3,362)	(18,958)	(40,725)	(176)
18	EFFECT OF CNIT DEFERRED TAX ON FIT	12	(548,174)	(383,480)	(109,542)	(2,933)	(16,538)	(35,527)	(154)
19	FEDERAL INCOME TAX		5,239,012	2,835,461	(124,770)	165,508	1,352,397	667,988	342,427
20	STATE NET INCOME TAX (LINE 9)		(796,184)	(820,032)	(530,651)	39,336	354,712	52,553	107,898
21	TOTAL INCOME TAXES		4,442,828	2,015,429	(655,420)	204,844	1,707,109	720,541	450,326

COLUMBIA GAS OF PENNSYLVANIA, INC.
ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 12 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	DESCRIPTION (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	RS/RDS (D)	SGS/SGDS (E)	LGS (F)	SDS (G)	LDS (H)	MDS (I)
1	DESIGN DAY	1	781,900	477,100	180,600	9,300	41,700	73,200	0
2	PERCENT		100.000%	61.018%	23.098%	1.189%	5.333%	9.362%	0.000%
3	THROUGHPUT EXCLUDING TRANSPORTATION	2	32,319,197	23,112,788	8,213,924	931,484	0	0	61,000
4	PERCENT		100.000%	71.514%	25.415%	2.882%	0.000%	0.000%	0.189%
5	THROUGHPUT EXCLUDING MDS	3	71,872,223	32,785,788	13,343,450	931,484	7,023,159	17,788,342	0
6	PERCENT		100.000%	45.617%	18.566%	1.296%	9.772%	24.750%	0.000%
7	GAS PURCHASED EXPENSE	4	150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
8	PERCENT		100.000%	72.118%	25.034%	2.680%	0.000%	0.000%	0.168%
9	COMPOSITE ALLOCATORS 1 & 3	5							
10	PERCENT		100.000%	61.213%	23.975%	0.712%	4.328%	9.772%	0.000%
11	AVERAGE NO. OF CUSTOMERS	6	415,347	378,379	36,372	79	416	91	10
12	PERCENT		100.000%	91.099%	8.757%	0.019%	0.100%	0.022%	0.002%
13	DISTRIBUTION UNCOLLECTIBLES	7	3,076,904	2,634,761	420,478	4,012	7,222	9,629	802
14	PERCENT		100.000%	85.630%	13.666%	0.130%	0.235%	0.313%	0.026%
15	CURRENT GMB/GTS REVENUE	8	32,051,476	-	2,862,902	5,587,447	9,520,329	12,850,848	1,229,950
16	PERCENT		100.000%	0.000%	8.932%	17.433%	29.703%	40.094%	3.837%
17	DIRECT ASSIGNMENT - CUSTOMER DEPOSITS	9	1,962,296	1,502,111	460,185	-	-	-	-
18	PERCENT		100.000%	76.549%	23.451%	0.000%	0.000%	0.000%	0.000%
19	FORFEITED DISCOUNTS	10	751,992	610,142	124,726	753	7,695	7,653	1,024
20	PERCENT		100.000%	81.137%	16.586%	0.100%	1.023%	1.018%	0.136%
21	DIST. PLANT EXCL ACCTS 375.70, 375.71, & 387	11	1,425,838,257	997,140,282	284,791,373	7,533,167	43,193,259	92,786,291	393,885
22	PERCENT		100.000%	69.934%	19.974%	0.528%	3.029%	6.507%	0.028%
23	GROSS PLANT	12	1,477,108,215	1,033,324,551	295,172,663	7,900,953	44,564,034	95,731,037	414,977
24	PERCENT		100.000%	69.956%	19.983%	0.535%	3.017%	6.481%	0.028%

COLUMBIA GAS OF PENNSYLVANIA, INC.
ALLOCATION FACTORS (CONT.)
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE - CORRECTED

EXHIBIT JES-2R
PAGE 13 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	DESCRIPTION (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	RS/RDS (D)	SGS/SGDS (E)	LGS (F)	SDS (G)	LDS (H)	MDS (I)
1	MAINS - ACCOUNT 376	13	911,044,198	557,544,413	218,370,727	6,485,087	39,420,584	89,005,996	217,392
2	PERCENT		100.000%	61.198%	23.969%	0.712%	4.327%	9.770%	0.024%
3	COMPOSITE DIRECT PLANT - ACCTS 376 & 380	14	1,285,044,803	900,745,193	248,452,309	6,634,672	39,760,891	89,196,717	255,022
4	PERCENT		100.000%	70.094%	19.334%	0.516%	3.094%	6.941%	0.020%
5	DIRECT ASSIGNMENT - SERVICES	15	228,607,626	209,802,788	18,388,728	91,824	208,528	115,758	-
6	PERCENT		100.000%	91.774%	8.044%	0.040%	0.091%	0.051%	0.000%
7	DIRECT ASSIGNMENT - METERS	16	24,235,911	18,173,549	5,739,937	66,820	196,940	55,413	3,252
8	PERCENT		100.000%	74.986%	23.684%	0.276%	0.813%	0.229%	0.013%
9	DIRECT ASSIGNMENT - IND M & R	17	6,712,184	-	4,490,787	397,657	1,309,527	514,212	-
10	PERCENT		100.000%	0.000%	66.905%	5.924%	19.510%	7.661%	0.000%
11	OTHER DISTRIBUTION O & M EXPENSES	18	33,374,478	23,124,558	7,155,367	182,615	973,842	1,932,163	5,933
12	PERCENT		100.000%	69.288%	21.440%	0.547%	2.918%	5.789%	0.018%
13	O & M EXCL GAS PUR, UNCOLLECTIBLES, & A & G	19	60,329,525	44,131,189	11,173,491	301,637	1,543,747	3,105,659	73,803
14	PERCENT		100.000%	73.150%	18.521%	0.500%	2.559%	5.148%	0.122%
15	MINIMUM SYSTEM MAINS	20							
16	PERCENT		100.000%	82.841%	12.726%	0.335%	1.504%	2.594%	0.000%
17	LARGE CUSTOMER RELATIONS	21	157	-	18	2	39	88	10
18	PERCENT		100.00%	0.000%	11.465%	1.274%	24.841%	56.051%	6.369%
19	AVERAGE - ALLOCATORS 5 & 20	22							
20	PERCENT		100.00%	72.026%	18.351%	0.524%	2.918%	6.183%	0.000%
21	UNBUNDLED UNCOLLECTIBLES	23	1,848,276	1,593,907	254,369	-	-	-	-
22	PERCENT		100.000%	86.237%	13.763%	0.000%	0.000%	0.000%	0.000%
23	LABOR	24	24,202,825	17,244,564	4,989,629	125,676	630,321	1,204,783	7,851
24	PERCENT		100.000%	71.250%	20.616%	0.519%	2.604%	4.978%	0.032%
25	SALES AND CHOICE TRANSPORTATION	25	43,479,194	32,785,788	9,700,922	931,484	-	-	61,000
26	PERCENT		100.000%	75.406%	22.312%	2.142%	0.000%	0.000%	0.140%

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - PROFORMA @ PROPOSED RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 1 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
1	TOTAL REVENUE [PAGE 6]		456,618,492	336,128,678	89,820,733	6,171,236	10,115,601	12,878,703	1,503,541
2	PRODUCTS PURCHASED [PAGE 7]		149,947,002	108,320,476	37,601,396	4,025,130	-	-	251,625
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		138,880,661	110,662,804	20,729,532	526,565	2,407,262	4,412,141	142,356
4	DEPRECIATION & AMORTIZATION [PAGE 5]		41,961,336	32,611,939	6,783,816	166,819	822,336	1,563,557	12,870
5	TAXES OTHER THAN INCOME [PAGE 9]		3,688,203	2,831,235	638,896	15,609	72,418	128,313	1,732
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		334,477,202	254,426,454	65,753,640	4,734,123	3,302,016	6,104,011	408,583
7	OPERATING INCOME BEFORE TAXES		121,889,665	81,702,224	24,067,094	1,437,113	6,813,585	6,774,692	1,094,958
8	INCOME TAXES		36,054,400	22,753,277	7,566,887	521,407	2,535,787	2,226,243	450,799
9	INVESTMENT TAX CREDIT	12	(360,239)	(277,582)	(58,687)	(1,481)	(7,529)	(14,860)	(101)
10	NET INCOME TAXES		35,694,161	22,475,695	7,508,201	519,926	2,528,258	2,211,383	450,698
11	OPERATING INCOME		86,195,504	59,226,529	16,558,893	917,187	4,285,327	4,563,309	644,259
12	RATE BASE [PAGE 10]		1,011,680,660	775,701,321	169,727,446	5,552,414	20,035,368	40,429,327	234,783
13	RATE OF RETURN EARNED ON RATE BASE		8.520%	7.635%	9.756%	16.519%	21.389%	11.287%	274.406%
14	UNITIZED RETURN		1.00	0.90	1.15	1.94	2.51	1.32	32.21

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE OF RETURN BY CLASS - CURRENT @ CURRENT RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
1	TOTAL REVENUE [PAGE 6]		379,306,896	274,348,980	75,464,783	5,589,146	9,533,913	12,867,692	1,502,383
2	PRODUCTS PURCHASED [PAGE 7]		150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
3	OPERATING & MAINTENANCE EXPENSES [PAGES 7 & 8]		137,753,458	109,762,056	20,520,222	518,078	2,398,781	4,411,981	142,340
4	DEPRECIATION & AMORTIZATION [PAGE 5]		41,961,336	32,611,939	6,783,816	166,819	822,336	1,563,557	12,870
5	TAXES OTHER THAN INCOME [PAGE 9]		3,688,203	2,831,235	638,896	15,609	72,418	128,313	1,732
6	TOTAL EXPENSES & TAXES OTHER THAN INCOME		333,601,624	253,525,706	65,544,330	4,725,637	3,293,535	6,103,851	408,566
7	OPERATING INCOME BEFORE TAXES		45,705,272	20,823,274	9,920,454	863,509	6,240,378	6,763,841	1,093,816
8	INCOME TAXES [PAGE 11]		4,442,828	(2,507,531)	1,696,951	283,398	2,297,943	2,221,740	450,326
9	INVESTMENT TAX CREDIT	12	(360,239)	(277,582)	(58,687)	(1,481)	(7,529)	(14,860)	(101)
10	NET INCOME TAXES		4,082,589	(2,785,113)	1,638,265	281,918	2,290,414	2,206,880	450,225
11	OPERATING INCOME		41,622,683	23,608,386	8,282,189	581,591	3,949,964	4,556,961	643,591
12	RATE BASE [PAGE 10]		1,011,680,660	775,701,321	169,727,446	5,552,414	20,035,368	40,429,327	234,783
13	RATE OF RETURN EARNED ON RATE BASE		4.114%	3.043%	4.880%	10.475%	19.715%	11.271%	274.121%
14	UNITIZED RETURN		1.00	0.74	1.19	2.55	4.79	2.74	66.63

COLUMBIA GAS OF PENNSYLVANIA, INC.
GROSS PLANT (Accounts 101 & 106)
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 3 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	301-305	INTANGIBLE PLANT	11	13,197,924	10,170,320	2,146,906	53,320	277,024	546,658	3,695
2	350-362	UNDERGROUND STORAGE PLANT	25	6,014,913	4,535,605	1,342,047	128,839	-	-	8,421
		DISTRIBUTION PLANT								
3	374.10	LAND - CITY GATE & M/L IND M&R	22	168,844	136,017	34,655	990	5,507	11,676	-
4	374.20	LAND - OTHER DISTRIBUTION	22	480,964	346,419	88,262	2,520	14,025	29,738	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	22	95,361	68,685	17,500	500	2,781	5,896	-
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	22	1,783,038	1,284,251	327,205	9,343	51,993	110,245	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		3	-	-	-	-	-	3
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	22	13	10	2	-	-	1	-
9	374.50	RIGHTS OF WAY	22	3,231,844	2,327,768	593,076	16,935	94,241	199,825	-
10	374.50	DIRECT - RIGHTS OF WAY		1,195	-	-	-	-	-	1,195
11	375.20	M & R STRUCTURES - CITY GATE	22	813,126	585,662	149,217	4,261	23,711	50,276	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	22	4,012	2,890	736	21	117	248	-
13	375.40	M & R STRUCTURES - REGULATING	22	2,714,399	1,955,073	498,119	14,223	79,152	167,831	-
14	375.60	M & R STRUCTURES - DIST. IND. M & R	17	87,692	(0)	58,671	5,195	17,109	6,718	-
15	375.70	M & R STRUCTURES - OTHER	11	4,150,247	3,198,181	675,121	16,767	87,114	171,903	1,162
16	375.71	M & R STRUCTURES - OTHER LEASED	11	1,031,960	795,228	167,869	4,169	21,661	42,744	289
17	375.80	M & R STRUCTURES - COMMUNICATION	22	16,515	11,895	3,031	87	482	1,021	-
18	376.00	MAINS	22	811,843,757	584,738,584	148,981,448	4,254,061	23,673,364	50,196,300	-
19	376.00	DIRECT - MAINS		98,881	-	-	-	-	-	98,881
20	376.08	MAINS-CSL REPLACEMENTS	22	23,059,830	16,609,073	4,231,709	120,834	672,425	1,425,789	-
21	376.30	MAINS-BARE STEEL	22	75,183,814	54,151,894	13,796,982	393,963	2,192,360	4,648,615	-
22	376.30	DIRECT - MAINS-BARE STEEL		118,511	-	-	-	-	-	118,511
23	376.80	MAINS-CAST IRON	22	739,405	532,564	135,688	3,875	21,561	45,717	-
24	378.10	M & R EQUIP - GENERAL	22	58,867	42,400	10,803	309	1,717	3,640	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	22	18,916,204	13,624,586	3,471,313	99,121	551,597	1,169,589	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		1,178	-	-	-	-	-	1,178
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	22	486,506	350,411	89,279	2,549	14,187	30,081	-
28	379.10	M & R EQUIP - CITY GATE	22	147,820	106,469	27,127	775	4,310	9,140	-
29	379.11	M & R EQUIP - EXCHANGE GAS	22	5,974	4,303	1,096	31	174	369	-
30	380.00	SERVICES	15	373,962,974	343,200,780	30,081,582	149,585	340,306	190,721	-
31	380.00	DIRECT - SERVICES		37,630	-	-	-	-	-	37,630
32	380.12	CSL REPLACEMENT	15	-	-	-	-	-	-	-
33	381.00	METERS	16	34,301,875	25,721,261	8,124,056	94,673	278,874	78,551	4,459
34	381.10	AUTOMATIC METER READING	16	20,548,041	15,407,948	4,866,598	56,713	167,056	47,055	2,671
35	382.00	METER INSTALLATIONS	16	35,468,816	26,596,292	8,400,435	97,894	288,362	81,224	4,611
36	383.00	HOUSE REGULATORS	16	10,741,363	8,054,411	2,543,984	29,646	87,327	24,598	1,396
37	384.00	HOUSE REG INSTALLATIONS	16	3,864,772	2,897,999	915,333	10,667	31,421	8,850	502
38	385.00	IND M&R EQUIPMENT	17	5,355,556	-	3,583,135	317,263	1,044,869	410,289	-
39	385.00	DIRECT - IND M&R EQUIPMENT		122,846	-	-	-	-	-	122,846
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	1,356,628	-	907,652	80,367	264,678	103,931	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	16,603	12,795	2,701	67	349	688	5
42	387.20	OTHER EQUIP ODORIZATION	11	121,943	93,969	19,836	493	2,560	5,051	34
43	387.42	OTHER EQUIP RADIO	11	130,407	100,492	21,213	527	2,737	5,402	37
44	387.44	OTHER EQUIP COMMUNICATION	11	664,599	512,140	108,110	2,685	13,950	27,528	186
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	259,436	199,921	42,203	1,048	5,446	10,748	73
46		TOTAL DISTRIBUTION PLANT		##########	##########	232,975,744	5,792,155	30,057,518	59,321,996	395,670
47	389-398	GENERAL PLANT	11	25,681,927	19,790,493	4,177,679	103,755	539,064	1,063,745	7,191
48	TOTAL GROSS PLANT			##########	##########	240,642,377	6,078,069	30,873,606	60,932,399	414,977

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEPRECIATION RESERVE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 4 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	301-305	INTANGIBLE PLANT	11	4,670,206	3,598,861	759,702	18,868	98,028	193,440	1,308
2	350-362	UNDERGROUND STORAGE PLANT	25	1,332,255	1,004,600	297,253	28,537	-	-	1,865
		DISTRIBUTION PLANT								
3	374.10	LAND - CITY GATE & M/L IND M&R	22	-	-	-	-	-	-	-
4	374.20	LAND - OTHER DISTRIBUTION	22	(24,311)	(17,510)	(4,461)	(127)	(709)	(1,503)	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	22	-	-	-	-	-	-	-
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	22	635,353	457,619	116,594	3,329	18,527	39,284	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		1	-	-	-	-	-	1
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	22	-	-	-	-	-	-	-
9	374.50	RIGHTS OF WAY	22	1,495,661	1,077,265	274,469	7,837	43,614	92,477	-
10	374.50	DIRECT - RIGHTS OF WAY		664	-	-	-	-	-	664
11	375.20	M & R STRUCTURES - CITY GATE	22	-	-	-	-	-	-	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	22	-	-	-	-	-	-	-
13	375.40	M & R STRUCTURES - REGULATING	22	789,197	568,427	144,826	4,135	23,013	48,796	-
14	375.60	M & R STRUCTURES - DIST. IND. M & R	17	71,206	-	47,640	4,218	13,892	5,455	-
15	375.70	M & R STRUCTURES - OTHER	11	2,143,906	1,652,094	348,749	8,661	45,001	88,801	600
16	375.71	M & R STRUCTURES - OTHER LEASED	11	971,923	748,964	158,103	3,927	20,401	40,257	272
17	375.80	M & R STRUCTURES - COMMUNICATION	22	5,681	4,092	1,043	30	166	351	-
18	376.00	MAINS	22	121,479,094	87,496,532	22,292,629	636,551	3,542,330	7,511,052	-
19	376.00	DIRECT - MAINS		58,002	-	-	-	-	-	58,002
20	376.08	MAINS-CSL REPLACEMENTS	22	-	-	-	-	-	-	-
21	376.30	MAINS-BARE STEEL	22	45,736,016	32,941,823	8,393,016	239,657	1,333,662	2,827,858	-
22	376.30	DIRECT - MAINS-BARE STEEL		96,966	-	-	-	-	-	96,966
23	376.80	MAINS-CAST IRON	22	12,008	8,649	2,204	63	350	743	-
24	378.10	M & R EQUIP - GENERAL	22	-	-	-	-	-	-	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	22	6,461,419	4,653,902	1,185,735	33,858	188,415	399,510	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		870	-	-	-	-	-	870
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	22	-	-	-	-	-	-	-
28	379.10	M & R EQUIP - CITY GATE	22	94,719	68,222	17,382	496	2,762	5,857	-
29	379.11	M & R EQUIP - EXCHANGE GAS	22	-	-	-	-	-	-	-
30	380.00	SERVICES	15	101,680,586	93,316,341	8,179,186	40,672	92,529	51,857	-
31	380.00	DIRECT - SERVICES		21,869	-	-	-	-	-	21,869
32	380.12	CSL REPLACEMENT	15	-	-	-	-	-	-	-
33	381.00	METERS	16	14,998,136	11,246,352	3,552,159	41,395	121,935	34,346	1,950
34	381.10	AUTOMATIC METER READING	16	4,440,562	3,329,755	1,051,703	12,256	36,102	10,169	577
35	382.00	METER INSTALLATIONS	16	10,435,222	7,824,851	2,471,478	28,801	84,838	23,897	1,357
36	383.00	HOUSE REGULATORS	16	2,868,259	2,150,764	679,319	7,916	23,319	6,568	373
37	384.00	HOUSE REG INSTALLATIONS	16	2,788,621	2,091,048	660,457	7,697	22,672	6,386	363
38	385.00	IND M&R EQUIPMENT	17	3,181,978	-	2,128,902	188,500	620,804	243,771	-
39	385.00	DIRECT - IND M&R EQUIPMENT		44,342	-	-	-	-	-	44,342
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	73,950	0	49,476	4,381	14,428	5,665	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	-	-	-	-	-	-	-
42	387.20	OTHER EQUIP ODORIZATION	11	-	-	-	-	-	-	-
43	387.42	OTHER EQUIP RADIO	11	-	-	-	-	-	-	-
44	387.44	OTHER EQUIP COMMUNICATION	11	-	-	-	-	-	-	-
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	545,616	420,452	88,755	2,204	11,453	22,599	153
46		TOTAL DISTRIBUTION PLANT		321,107,516	250,039,642	51,839,362	1,276,458	6,259,502	11,464,195	228,358
47	389-398	GENERAL PLANT	11	15,890,423	12,245,160	2,584,895	64,197	333,540	658,181	4,449
48	TOTAL DEPRECIATION RESERVE			[illegible]0,400	266,888,263	55,481,212	1,388,059	6,691,070	12,315,816	235,980

COLUMBIA GA[illegible]ENNSYLVANIA, INC.
DEPRECIATION AND AMORTIZATION EXPENSE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 5 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT. NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	301-305	INTANGIBLE PLANT	11	1,756,935	1,353,894	285,801	7,098	36,878	72,772	492
2	350-362	UNDERGROUND STORAGE PLANT	25	163,868	123,566	36,562	3,510	-	-	229
		DISTRIBUTION PLANT								
3	374.10	LAND - CITY GATE & M/L IND M&R	22	-	-	-	-	-	-	-
4	374.20	LAND - OTHER DISTRIBUTION	22	-	-	-	-	-	-	-
5	374.30	LAND RIGHTS - CITY GATE MAIN LINE	22	-	-	-	-	-	-	-
6	374.40	LAND RIGHTS - OTHER DISTRIBUTION	22	35,574	25,623	6,528	186	1,037	2,200	-
7	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION		0	-	-	-	-	-	0
8	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	22	-	-	-	-	-	-	-
9	374.50	RIGHTS OF WAY	22	43,000	30,971	7,891	225	1,254	2,659	-
10	374.50	DIRECT - RIGHTS OF WAY		16	-	-	-	-	-	16
11	375.20	M & R STRUCTURES - CITY GATE	22	-	-	-	-	-	-	-
12	375.31	M & R STRUCTURES - LOCAL GAS PURCH	22	-	-	-	-	-	-	-
13	375.40	M & R STRUCTURES - REGULATING	22	81,608	58,779	14,976	428	2,380	5,046	-
14	375.60	M & R STRUCTURES - DIST. IND. M & R	17	973	0	651	58	190	75	-
15	375.70	M & R STRUCTURES - OTHER	11	161,680	124,591	26,301	653	3,394	6,697	45
16	375.71	M & R STRUCTURES - OTHER LEASED	11	182,501	140,635	29,687	737	3,831	7,559	51
17	375.80	M & R STRUCTURES - COMMUNICATION	22	342	246	63	2	10	21	-
18	376.00	MAINS	22	16,635,509	11,981,891	3,052,782	87,170	485,091	1,028,574	-
19	376.00	DIRECT - MAINS		1,641	-	-	-	-	-	1,641
20	376.08	MAINS-CSL REPLACEMENTS	22	-	-	-	-	-	-	-
21	376.30	MAINS-BARE STEEL	22	1,725,309	1,242,671	316,612	9,041	50,310	106,676	-
22	376.30	DIRECT - MAINS-BARE STEEL		2,501	-	-	-	-	-	2,501
23	376.80	MAINS-CAST IRON	22	409	295	75	2	12	25	-
24	378.10	M & R EQUIP - GENERAL	22	-	-	-	-	-	-	-
25	378.20	M & R EQUIP - GENERAL - REGULATING	22	663,688	406,002	103,442	2,954	16,437	34,853	-
26	378.20	DIRECT - M & R EQUIP-GEN-REG		29	-	-	-	-	-	29
27	378.30	M & R EQUIP - LOCAL GAS PURCHASES	22	-	-	-	-	-	-	-
28	379.10	M & R EQUIP - CITY GATE	22	5,023	3,618	922	26	147	311	-
29	379.11	M & R EQUIP - EXCHANGE GAS	22	-	-	-	-	-	-	-
30	380.00	SERVICES	15	10,309,953	9,461,856	829,333	4,124	9,382	5,258	-
31	380.00	DIRECT - SERVICES		963	-	-	-	-	-	963
32	380.12	CSL REPLACEMENT	15	-	-	-	-	-	-	-
33	381.00	METERS	16	835,931	626,823	197,982	2,307	6,796	1,914	109
34	381.10	AUTOMATIC METER READING	16	1,778,260	1,333,428	421,163	4,908	14,457	4,072	231
35	382.00	METER INSTALLATIONS	16	707,167	530,269	167,485	1,952	5,749	1,619	92
36	383.00	HOUSE REGULATORS	16	284,993	213,702	67,498	787	2,317	653	37
37	384.00	HOUSE REG INSTALLATIONS	16	72,465	54,338	17,163	200	589	166	9
38	385.00	IND M&R EQUIPMENT	17	245,096	0	163,982	14,520	47,818	18,777	-
39	385.00	DIRECT - IND M&R EQUIPMENT		4,644	-	-	-	-	-	4,644
40	385.10	IND M&R EQUIPMENT - LG VOLUME	17	4,212	-	2,818	250	822	323	-
41	387.10	OTHER EQUIP DISTRIBUTION	11	-	-	-	-	-	-	-
42	387.20	OTHER EQUIP ODORIZATION	11	-	-	-	-	-	-	-
43	387.42	OTHER EQUIP RADIO	11	-	-	-	-	-	-	-
44	387.44	OTHER EQUIP COMMUNICATION	11	-	-	-	-	-	-	-
45	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	11	49,407	38,073	8,037	200	1,037	2,046	14
46		TOTAL DISTRIBUTION PLANT		33,732,894	26,273,812	5,435,390	130,728	653,060	1,229,522	10,382
47	389-398	GENERAL PLANT	11	1,443,308	1,112,213	234,783	5,831	30,295	59,782	404
48		NET DEPRECIATION & AMORTIZATION EXPENSE		37,097,005	28,863,486	5,992,535	147,167	720,233	1,362,076	11,508
49		AMORTIZATION OF NET NEGATIVE SALVAGE	11	4,864,331	3,748,454	791,281	19,652	102,102	201,481	1,362
50	TOTAL AMORTIZATION AND DEPRECIATION EXPENSE			41,961,336	32,611,939	6,783,816	166,819	822,336	1,563,557	12,870

COLUMBIA GAS OF PENNSYLVANIA, INC.
OPERATING REVENUE @ PROPOSED & CURRENT RATES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 6 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
		PROPOSED OPERATING REVENUE								
		SALES REVENUE								
1	480/481	SALES BASE REVENUE		214,051,481	173,800,330	38,100,661	2,130,998	-	-	19,492
2		USP REVENUE		8,309,047	8,309,047	-	-	-	-	-
3		STAS REVENUE		-	-	-	-	-	-	-
4		UNBUNDLED UNCOLLECTIBLES REVENUE		1,848,276	1,363,655	484,621	-	-	-	-
5		GAS PROCUREMENT REVENUE	2	465,287	332,745	118,253	13,410	-	-	879
6		GAS COST REVENUE		141,900,550	102,129,786	35,494,009	4,025,130	-	-	251,625
7		TOTAL SALES REVENUE		366,574,641	285,935,563	74,197,544	6,169,538	-	-	271,996
		TRANSPORTATION REVENUE								
8	489.00	TRANSPORTATION BASE REVENUE		73,174,899	40,288,371	13,273,361	-	9,900,113	9,492,046	221,008
9		USP REVENUE		2,649,024	2,649,024	-	-	-	-	-
10		STAS REVENUE		-	-	-	-	-	-	-
11		FLEX REVENUE		4,613,061	-	32,146		201,904	3,369,813	1,009,198
12		GAS COST REVENUE		8,298,077	6,190,690	2,107,387	-	-	-	-
13		TOTAL TRANSPORTATION REVENUE		88,635,061	49,028,085	15,412,894	-	10,102,017	12,861,859	1,230,206
		MISCELLANEOUS REVENUE								
14	487.00	FORFEITED DISCOUNTS	10	944,367	766,231	156,633	944	9,661	9,614	1,284
15	488.00	MISCELLANEOUS REVENUE	6	146,687	133,632	12,845	28	147	32	3
16	493.00	RENTS	11	173,011	133,322	28,144	699	3,632	7,166	48
17	495.00	OTHER	6	144,725	131,845	12,674	28	145	32	3
18		TOTAL MISCELLANEOUS REVENUE		1,408,790	1,165,030	210,295	1,699	13,584	16,844	1,339
19		TOTAL PROPOSED OPERATING REVENUE		456,618,492	336,128,678	89,820,733	6,171,236	10,115,601	12,878,703	1,503,541
		CURRENT OPERATING REVENUE								
		SALES REVENUE								
20	480/481	SALES BASE REVENUE		138,032,974	112,543,267	23,906,093	1,584,132	-	-	19,492
21		USP REVENUE		8,309,047	8,309,047	-	-	-	-	-
22		STAS REVENUE		(181,366)	(151,797)	(27,731)	(1,815)	-	-	(23)
23		UNBUNDLED UNCOLLECTIBLES REVENUE		1,848,276	1,363,655	484,621	-	-	-	-
24		GAS COST REVENUE		141,900,550	102,129,786	35,494,009	4,025,130	-	-	251,625
25		TOTAL SALES REVENUE		289,909,481	224,193,948	59,856,992	5,587,447	-	-	271,094
		TRANSPORTATION REVENUE								
26	489.00	TRANSPORTATION BASE REVENUE		72,604,033	40,288,371	13,273,361	-	9,329,247	9,492,046	221,008
27		USP REVENUE		2,649,024	2,649,024	-	-	-	-	-
28		STAS REVENUE		(75,570)	(38,083)	(15,398)	-	(10,822)	(11,011)	(256)
29		FLEX REVENUE		4,613,061	-	32,146	-	201,904	3,369,813	1,009,198
30		GAS COST REVENUE		8,298,077	6,190,690	2,107,387	-	-	-	-
31		TOTAL TRANSPORTATION REVENUE		87,988,625	48,990,002	15,397,496	-	9,520,329	12,850,848	1,229,950
		MISCELLANEOUS REVENUE								
32	487.00	FORFEITED DISCOUNTS	10	944,367	766,231	156,633	944	9,661	9,614	1,284
33	488.00	MISCELLANEOUS REVENUE	6	146,687	133,632	12,845	28	147	32	3
34	493.00	RENTS	11	173,011	133,322	28,144	699	3,632	7,166	48
35	495.00	OTHER	6	144,725	131,845	12,674	28	145	32	3
36		TOTAL MISCELLANEOUS REVENUE		1,408,790	1,165,030	210,295	1,699	13,584	16,844	1,339
37		TOTAL CURRENT OPERATING REVENUE		379,306,896	274,348,980	75,464,783	5,589,146	9,533,913	12,867,692	1,502,383

COLUMBIA GAS OF PENNSYLVANIA, INC.
PRODUCTION & DISTRIBUTION O&M EXPENSES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 7 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
		PURCHASED GAS EXPENSES								
1		GAS PURCHASED COST		149,947,002	108,320,476	37,601,396	4,025,130	-	-	251,625
2	807.00	PURCHASED GAS EXPENSE	4	1,036,138	747,242	259,387	27,769	-	-	1,741
3	807.00	GAS PROCUREMENT EXPENSE	4	465,287	335,556	116,480	12,470	-	-	782
4		TOTAL PURCHASED GAS		151,448,427	109,403,274	37,977,263	4,065,368	-	-	254,147
		UNDERGROUND STORAGE OPERATIONS EXPENSES								
5	816.00	WELLS	25	10,754	8,109	2,399	230	-	-	15
6	817.00	LINES	25	37,625	28,371	8,395	806	-	-	53
7	818.00	COMPRESSOR STATION	25	150,458	113,455	33,570	3,223	-	-	211
8	820.00	M & R	25	15,840	11,944	3,534	339	-	-	22
9	821.00	PURIFICATION	25	3,082	2,324	688	66	-	-	4
10	823.00	GAS LOSSES	25	2,052	1,547	458	44	-	-	3
11	825.00	STORAGE WELL ROYALTIES	25	5,977	4,507	1,334	128	-	-	8
12		TOTAL UNDERGROUND STORAGE OPERATIONS		225,787	170,257	50,378	4,836	-	-	316
		UNDERGROUND STORAGE MAINTENANCE EXPENSES								
13	832.00	WELLS	25	7,823	5,899	1,745	168	-	-	11
14	834.00	COMPRESSOR STATION	25	6,230	4,698	1,390	134	-	-	9
15	836.00	PURIFICATION	25	6,789	5,120	1,515	145	-	-	10
16		TOTAL UNDERGROUND STORAGE MAINTENANCE		20,843	15,717	4,650	447	-	-	29
17		TOTAL UNDERGROUND STORAGE		246,630	185,974	55,028	5,283	-	-	345
		DISTRIBUTION OPERATIONS EXPENSES								
18	870.00	SUPERVISION & ENGINEERING	18	4,666,895	3,524,952	849,048	20,488	98,098	173,469	840
19	871.00	LOAD DISPATCHING	13	124,644	89,754	22,868	653	3,633	7,706	30
20	874.00	MAINS & SERVICES	14	10,868,086	8,450,915	1,668,034	41,625	227,469	477,870	2,174
21	875.00	M & R - GENERAL	13	590,194	424,987	108,283	3,093	17,204	36,486	142
22	876.00	M & R - INDUSTRIAL	17	245,982	-	164,574	14,572	47,991	18,845	-
23	878.00	METERS & HOUSE REGULATORS	16	2,455,745	1,841,440	581,619	6,778	19,965	5,624	319
24	879.00	CUSTOMER INSTALLATIONS	16	4,813,089	3,609,095	1,139,932	13,284	39,130	11,022	626
25	880.00	OTHER	18	4,881,051	3,686,707	888,010	21,428	102,600	181,429	879
26	881.00	RENTS	18	273,398	206,501	49,739	1,200	5,747	10,162	49
27		TOTAL DISTRIBUTION OPERATIONS		28,919,083	21,834,350	5,472,107	123,120	561,838	922,611	5,058
		DISTRIBUTION MAINTENANCE EXPENSES								
28	885.00	SUPERVISION & ENGINEERING	18	51,399	38,822	9,351	226	1,080	1,911	9
29	886.00	STRUCTURES AND IMPROVEMENTS	13	52,374	37,713	9,609	274	1,527	3,238	13
30	887.00	MAINS	13	10,193,632	7,340,231	1,870,226	53,415	297,144	630,170	2,447
31	889.00	M & R - GENERAL	13	609,180	438,658	111,766	3,192	17,758	37,660	146
32	890.00	M & R - INDUSTRIAL	17	127,109	-	85,042	7,530	24,799	9,738	-
33	892.00	SERVICES	15	3,008,381	2,760,911	241,994	1,203	2,738	1,534	-
34	893.00	METERS & HOUSE REGULATORS	16	286,063	214,505	67,751	790	2,326	655	37
35	894.00	OTHER EQUIPMENT	18	796,193	601,372	144,851	3,495	16,736	29,595	143
36		TOTAL DISTRIBUTION MAINTENANCE		15,124,330	11,432,212	2,540,591	70,125	364,107	714,500	2,795
37		TOTAL DISTRIBUTION		44,043,414	33,266,562	8,012,698	193,245	925,945	1,637,111	7,853

COLUMBIA GAS OF PENNSYLVANIA, INC.
OTHER O&M EXPENSES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 8 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
		CUSTOMER ACCOUNTS EXPENSES								
1	901.00	SUPERVISION	6	-	-	-	-	-	-	-
2	902.00	METER READING	6	2,126,147	1,936,920	186,187	404	2,126	468	43
3	903.00	COLLECTING-DELINQUENT ACCTS	6	1,072,108	976,690	93,885	204	1,072	236	21
4	903.00	COLLECTING-CURRENT ACCTS	6	7,959	7,251	697	2	8	2	0
5	903.00	BILLING & ACCOUNTING	6	5,797,611	5,281,623	507,697	1,102	5,798	1,276	116
6	903.00	RENDERING BILLS	6	2,484,720	2,263,580	217,587	472	2,485	547	50
7	904.00	UNCOLLECTIBLES-DIS REVENUE	7	3,037,943	2,601,391	415,165	3,949	7,139	9,509	790
8	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE	7	38,961	33,362	5,324	51	92	122	10
9	904.00	UNCOLLECTIBLES-UNBUNDLED GAS	23	1,848,276	1,593,898	254,378	-	-	-	-
10	904.00	DIRECT USP UNCOLLECTIBLES		8,469,295	8,469,295	-	-	-	-	-
11	905.00	MISCELLANEOUS	6	17,448	15,895	1,528	3	17	4	0
12	921.00	OFFICE SUPPLIES & EXPENSES	6	4,212	3,837	369	1	4	1	-
13		TOTAL CUSTOMER ACCOUNTS		24,904,680	23,183,743	1,682,817	6,187	18,741	12,163	1,030
		CUST SERVICE & INFORMATION EXPENSES								
14	907.00	SUPERVISION	6	-	-	-	-	-	-	-
15	908.00	CUSTOMER ASSISTANCE	6	613,463	558,877	53,721	117	614	135	-
16	908.00	DIRECT USP/LIURP/HEEP		2,388,776	2,388,776	-	-	-	-	-
17	909.00	INFORMATIONAL & INSTRUCTIONAL EXPENSES	6	38,185	34,786	3,344	7	38	8	1
18	910.00	MISCELLANEOUS	6	600,792	547,321	52,611	114	601	132	12
19	910.00	LARGE CUSTOMER RELATIONS	21	986,406	0	113,091	12,567	245,033	552,890	62,824
20	921.00	OFFICE SUPPLIES & EXPENSES	6	9,085	8,277	796	2	9	2	-
21	931.00	RENTS - GENERAL	6	140	128	12	-	-	-	-
22		TOTAL CUST SERVICE & INFORMATION		4,636,846	3,538,165	223,575	12,807	246,295	553,168	62,837
		SALES EXPENSES								
23	912.00	DEMONSTRATION	6	650,917	592,985	57,001	124	651	143	13
24	913.00	ADVERTISING	6	128,865	117,396	11,285	25	129	28	3
25		TOTAL SALES		779,782	710,381	68,286	148	780	172	16
		ADMINISTRATIVE AND GENERAL EXPENSES								
26	920.00	SALARIES	19	3,908,071	3,036,923	631,153	16,453	76,715	142,058	4,768
27	921.00	OFFICE SUPPLIES & EXPENSES	19	2,016,774	1,567,215	325,709	8,491	39,589	73,310	2,461
28	922.00	ADMIN. EXPENSE TRANSFERRED	19	-	-	-	-	-	-	-
29	923.00	OUTSIDE SERVICES EMPLOYED	19	41,245,654	32,051,585	6,661,173	173,644	809,652	1,499,280	50,320
30	924.00	PROPERTY INSURANCE	19	157,493	122,386	25,435	663	3,092	5,725	192
31	925.00	INJURIES AND DAMAGES	19	3,725,912	2,895,369	601,735	15,686	73,140	135,437	4,546
32	926.00	EMPLOYEE PENSIONS & BENEFITS	24	8,294,725	6,339,824	1,486,581	35,584	159,839	270,242	2,654
33	928.00	REGULATORY COMMISSION EXPENSES	19	1,428,131	1,109,786	230,643	6,012	28,034	51,913	1,742
34	930.00	MISCELLANEOUS GENERAL	19	568,725	441,950	91,849	2,394	11,164	20,673	694
35	931.00	RENTS-GENERAL	19	295,199	229,396	47,675	1,243	5,795	10,731	360
36		TOTAL ADMINISTRATIVE & GENERAL		61,640,682	47,794,434	10,101,953	260,171	1,207,021	2,209,368	67,736
		TOTAL O & M EXPENSES		[redacted]0,461	218,082,532	58,121,618	4,543,208	2,398,781	4,411,981	[redacted]965

COLUMBIA GAS OF PENNSYLVANIA, INC.
TAXES OTHER THAN INCOME TAXES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 9 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO.	ACCOUNT TITLE	ALLOC FACTOR	TOTAL COMPANY	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
	(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)	(J)
		FEDERAL TAXES		$	$	$	$	$	$	$
1	408.00	FEDERAL UNEMPLOYMENT	24	45,196	34,544	8,100	194	871	1,473	15
2	408.00	FICA	24	2,190,869	1,674,525	392,648	9,399	42,218	71,379	701
3		TOTAL FEDERAL TAXES		2,236,065	1,709,069	400,748	9,593	43,089	72,851	716
		STATE TAXES								
4	408.00	PA PROPERTY TAXES	11	642,142	494,834	104,457	2,594	13,479	26,598	180
5	408.00	PA STATE UNEMPLOYMENT	24	161,920	123,759	29,019	695	3,120	5,275	52
6	408.00	STATE CAPITAL STOCK TAX	11	-	-	-	-	-	-	-
7	408.00	LICENSE AND FRANCHISE TAX	11	6,251	4,817	1,017	25	131	259	2
8	408.00	STATE SALES AND USE TAX	19	614,394	477,439	99,225	2,587	12,061	22,333	750
9	408.00	OTHER	19	27,431	21,316	4,430	116	539	997	34
10		TOTAL STATE TAXES		1,452,138	1,122,166	238,148	6,016	29,329	55,462	1,017
11		TOTAL TAXES OTHER THAN INCOME		3,688,203	2,831,235	638,896	15,609	72,418	128,313	1,732

COLUMBIA GAS OF PENNSYLVANIA, INC.
RATE BASE
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 10 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ACCOUNT TITLE (B)	ALLOC FACTOR (C)	TOTAL COMPANY (D) $	RS/RDS (E) $	SGS/SGDS (F) $	LGS (G) $	SDS (H) $	LDS (I) $	MDS (J) $
1	101-107	GROSS PLANT [PAGE 3]		1,477,108,215	1,138,166,787	240,642,377	6,078,069	30,873,606	60,932,399	414,977
2	117.00	GAS STORED UNDERGROUND - NON CURRENT	25	3,794,990	2,861,650	846,738	81,289	-	-	5,313
3	108-111	DEPRECIATION RESERVE [PAGE 4]		(343,000,400)	(266,888,263)	(55,481,212)	(1,388,059)	(6,691,070)	(12,315,816)	(235,980)
4	117.00	GAS LOST-UNDERGROUND STORAGE	1	(163,458)	(99,739)	(37,756)	(1,944)	(8,717)	(15,303)	-
5		NET PLANT		1,137,739,347	874,040,436	185,970,148	4,769,355	24,173,819	48,601,280	184,310
		WORKING CAPITAL								
6	154.00	MATERIALS & SUPPLIES	11	663,015	510,919	107,853	2,679	13,917	27,462	186
7	164.00	GAS STORED UNDERGROUND - FSS	25	74,526,147	56,197,186	16,628,274	1,596,350	-	-	104,337
8	165.00	PREPAYMENTS	19	1,651,928	1,283,697	266,786	6,955	32,427	60,048	2,015
9		CASH WORKING CAPITAL - GAS PURCHASES	4	-	-	-	-	-	-	-
10		CASH WORKING CAPITAL - ALL OTHER	19	-	-	-	-	-	-	-
11		TOTAL WORKING CAPITAL		76,841,090	57,991,802	17,002,913	1,605,983	46,344	87,510	106,538
		DEFERRED INCOME TAXES								
12	190.00	ACCUMULATED DEF INCOME TAX	12	3,351,427	2,582,442	545,981	13,774	70,045	138,246	938
13	282.00	ACCUMULATED DEF INCOME TAX	12	(203,338,966)	(156,682,840)	(33,125,951)	(835,723)	(4,249,784)	(8,387,732)	(56,935)
14	283.00	ACCUMULATED DEF INCOME TAX	12	(23,454)	(18,072)	(3,821)	(96)	(490)	(968)	(7)
15		TOTAL DEFERRED INCOME TAXES		(200,010,993)	(154,118,471)	(32,583,791)	(822,045)	(4,180,230)	(8,250,453)	(56,003)
16	235.00	CUSTOMER DEPOSITS	9	(2,671,287)	(2,044,844)	(626,444)	-	-	-	-
17	252.00	CUSTOMER ADVANCES	11	(217,497)	(167,603)	(35,380)	(879)	(4,565)	(9,009)	(61)
18		RATE BASE		1,011,680,660	775,701,321	169,727,446	5,552,414	20,035,368	40,429,327	234,783

COLUMBIA GAS OF PENNSYLVANIA, INC.
STATE/FEDERAL INCOME TAXES
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 11 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	ACCT NO. (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
	STATE INCOME TAX								
1	OPERATING INCOME BEFORE TAXES (PG. 2, LINE 8)		45,705,272	20,823,274	9,920,454	863,509	6,240,378	6,763,841	1,093,816
2	STATUTORY ADJUSTMENTS	12	(37,630,943)	(28,996,523)	(6,130,457)	(154,663)	(786,487)	(1,552,276)	(10,537)
3	INTEREST ON DEBT		(26,607,201)	(20,400,945)	(4,463,832)	(146,028)	(526,930)	(1,063,291)	(6,175)
4	PA BONUS DEPRECIATION ADJUSTMENT	12	(5,114,711)	(3,941,141)	(833,238)	(21,022)	(106,898)	(210,982)	(1,432)
5	STATE TAXABLE INCOME		(23,647,583)	(32,515,334)	(1,507,073)	541,796	4,820,064	3,937,292	1,075,673
6	NET OPERATING LOSS DEDUCTION	12	-	-	-	-	-	-	-
	STATE TAXABLE INCOME		(23,647,583)	(32,515,334)	(1,507,073)	541,796	4,820,064	3,937,292	1,075,673
7	STATE NET INCOME TAX @ 9.99%		(2,362,394)	(3,248,282)	(150,557)	54,125	481,524	393,335	107,460
8	DEFERRED INCOME TAXES	12	1,566,210	1,206,843	255,151	6,437	32,734	64,606	439
9	STATE INCOME TAX		(796,184)	(2,041,439)	104,595	60,563	514,258	457,942	107,898
	FEDERAL INCOME TAX								
10	OPERATING INCOME BEFORE TAXES (PG. 2, LINE 8)		45,705,272	20,823,274	9,920,454	863,509	6,240,378	6,763,841	1,093,816
11	STATE NET INCOME TAX (LINE 7)		2,362,394	3,248,282	150,557	(54,125)	(481,524)	(393,335)	(107,460)
12	STATUTORY ADJUSTMENTS (LINES 2 & 3)	12	(64,238,144)	(49,397,467)	(10,594,289)	(300,692)	(1,313,417)	(2,615,568)	(16,712)
13	FEDERAL TAXABLE INCOME		(16,170,478)	(25,325,912)	(523,279)	508,692	4,445,437	3,754,938	969,645
14	FEDERAL INCOME TAX @ 35%		(5,659,667)	(8,864,069)	(183,147)	178,042	1,555,903	1,314,228	339,376
15	DEFERRED INCOME TAXES	12	16,164,641	12,455,664	2,633,382	66,437	337,841	666,791	4,526
16	TAX REFUND AMORTIZATION	12	(4,089,420)	(3,151,103)	(666,207)	(16,808)	(85,469)	(168,689)	(1,145)
17	FLOW BACK OF EXCESS DEFERRED TAXES	12	(628,368)	(484,189)	(102,367)	(2,583)	(13,133)	(25,920)	(176)
18	EFFECT OF CNIT DEFERRED TAX ON FIT	12	(548,174)	(422,395)	(89,303)	(2,253)	(11,457)	(22,612)	(154)
19	FEDERAL INCOME TAX		5,239,012	(466,092)	1,592,356	222,836	1,783,685	1,763,799	342,427
20	STATE NET INCOME TAX (LINE 9)		(796,184)	(2,041,439)	104,595	60,563	514,258	457,942	107,898
21	TOTAL INCOME TAXES		4,442,828	(2,507,531)	1,696,951	283,398	2,297,943	2,221,740	450,326

COLUMBIA GAS OF PENNSYLVANIA, INC.
ALLOCATION FACTORS
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 12 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	DESCRIPTION (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	RS/RDS (D)	SGS/SGDS (E)	LGS (F)	SDS (G)	LDS (H)	MDS (I)
1	DESIGN DAY	1	781,900	477,100	180,600	9,300	41,700	73,200	0
2	PERCENT		100.000%	61.018%	23.098%	1.189%	5.333%	9.362%	0.000%
3	THROUGHPUT EXCLUDING TRANSPORTATION	2	32,319,197	23,112,788	8,213,924	931,484	0	0	61,000
4	PERCENT		100.000%	71.514%	25.415%	2.882%	0.000%	0.000%	0.189%
5	THROUGHPUT EXCLUDING MDS	3	71,872,223	32,785,788	13,343,450	931,484	7,023,159	17,788,342	0
6	PERCENT		100.000%	45.617%	18.566%	1.296%	9.772%	24.750%	0.000%
7	GAS PURCHASED EXPENSE	4	150,198,627	108,320,476	37,601,396	4,025,130	-	-	251,625
8	PERCENT		100.000%	72.118%	25.034%	2.680%	0.000%	0.000%	0.168%
9	COMPOSITE ALLOCATORS 1 & 3	5							
10	PERCENT		100.000%	61.213%	23.975%	0.712%	4.328%	9.772%	0.000%
11	AVERAGE NO. OF CUSTOMERS	6	415,347	378,379	36,372	79	416	91	10
12	PERCENT		100.000%	91.099%	8.757%	0.019%	0.100%	0.022%	0.002%
13	DISTRIBUTION UNCOLLECTIBLES	7	3,076,904	2,634,761	420,478	4,012	7,222	9,629	802
14	PERCENT		100.000%	85.630%	13.666%	0.130%	0.235%	0.313%	0.026%
15	CURRENT GMB/GTS REVENUE	8	32,051,476	-	2,862,902	5,587,447	9,520,329	12,850,848	1,229,950
16	PERCENT		100.000%	0.000%	8.932%	17.433%	29.703%	40.094%	3.837%
17	DIRECT ASSIGNMENT - CUSTOMER DEPOSITS	9	1,962,296	1,502,111	460,185	-	-	-	-
18	PERCENT		100.000%	76.549%	23.451%	0.000%	0.000%	0.000%	0.000%
19	FORFEITED DISCOUNTS	10	751,992	610,142	124,726	753	7,695	7,653	1,024
20	PERCENT		100.000%	81.137%	16.586%	0.100%	1.023%	1.018%	0.136%
21	DIST. PLANT EXCL ACCTS 375.70, 375.71, & 387	11	1,425,838,257	1,098,757,644	231,938,691	5,766,399	29,923,703	59,057,935	393,885
22	PERCENT		100.000%	77.060%	16.267%	0.404%	2.099%	4.142%	0.028%
23	GROSS PLANT	12	1,477,108,215	1,138,166,787	240,642,377	6,078,069	30,873,606	60,932,399	414,977
24	PERCENT		100.000%	77.054%	16.291%	0.411%	2.090%	4.125%	0.028%

COLUMBIA GAS OF PENNSYLVANIA, INC.
ALLOCATION FACTORS (CONT.)
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
AVERAGE STUDY- ALLOCATORS 5 & 20 - CORRECTED

EXHIBIT JES-3R
PAGE 13 OF 13
WITNESS: J.E. SKIRTICH

LINE NO.	DESCRIPTION (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	RS/RDS (D)	SGS/SGDS (E)	LGS (F)	SDS (G)	LDS (H)	MDS (I)
1	MAINS - ACCOUNT 376	13	911,044,198	656,032,116	167,145,827	4,772,733	26,559,710	56,316,421	217,392
2	PERCENT		100.000%	72.009%	18.347%	0.524%	2.915%	6.182%	0.024%
3	COMPOSITE DIRECT PLANT - ACCTS 376 & 380	14	1,285,044,803	999,232,896	197,227,409	4,922,318	26,900,016	56,507,143	255,022
4	PERCENT		100.000%	77.759%	15.348%	0.383%	2.093%	4.397%	0.020%
5	DIRECT ASSIGNMENT - SERVICES	15	228,607,626	209,802,788	18,388,728	91,824	208,528	115,758	-
6	PERCENT		100.000%	91.774%	8.044%	0.040%	0.091%	0.051%	0.000%
7	DIRECT ASSIGNMENT - METERS	16	24,235,911	18,173,549	5,739,937	66,820	196,940	55,413	3,252
8	PERCENT		100.000%	74.986%	23.684%	0.276%	0.813%	0.229%	0.013%
9	DIRECT ASSIGNMENT - IND M & R	17	6,712,184	-	4,490,787	397,657	1,309,527	514,212	-
10	PERCENT		100.000%	0.000%	66.905%	5.924%	19.510%	7.661%	0.000%
11	OTHER DISTRIBUTION O & M EXPENSES	18	33,374,478	25,208,208	6,071,698	146,408	701,684	1,240,546	5,933
12	PERCENT		100.000%	75.531%	18.193%	0.439%	2.102%	3.717%	0.018%
13	O & M EXCL GAS PUR, UNCOLLECTIBLES, & A & G	19	60,329,525	46,880,900	9,743,402	253,908	1,184,530	2,192,983	73,803
14	PERCENT		100.000%	77.708%	16.150%	0.421%	1.963%	3.635%	0.122%
15	MINIMUM SYSTEM MAINS	20							
16	PERCENT		100.000%	82.841%	12.726%	0.335%	1.504%	2.594%	0.000%
17	LARGE CUSTOMER RELATIONS	21	157	-	18	2	39	88	10
18	PERCENT		100.00%	0.000%	11.465%	1.274%	24.841%	56.051%	6.369%
19	AVERAGE - ALLOCATORS 5 & 20	22							
20	PERCENT		100.00%	72.026%	18.351%	0.524%	2.916%	6.183%	0.000%
21	UNBUNDLED UNCOLLECTIBLES	23	1,848,276	1,593,907	254,369	-	-	-	-
22	PERCENT		100.000%	86.237%	13.763%	0.000%	0.000%	0.000%	0.000%
23	LABOR	24	24,202,825	18,498,407	4,337,523	103,920	466,506	788,618	7,851
24	PERCENT		100.000%	76.431%	17.922%	0.429%	1.927%	3.258%	0.032%
25	SALES AND CHOICE TRANSPORTATION	25	43,479,194	32,785,788	9,700,922	931,484	-	-	61,000
26	PERCENT		100.000%	75.406%	22.312%	2.142%	0.000%	0.000%	0.140%

Columbia Gas of Pennsylvania, Inc.
Allocation Factors Comparison - "Corrected" vs. "As Filed"

LINE NO.	DESCRIPTION (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	RS/RDS (D)	SGS/SGDS (E)	LGS (F)	SDS (G)	LDS (H)	MDS (I)
1	DESIGN DAY	1							
2	Corrected Volume		781,900	477,100	180,600	9,300	41,700	73,200	0
3	Corrected - %		100.000%	61.018%	23.098%	1.189%	5.333%	9.362%	0.000%
4	As Filed Volume		781,900	476,000	181,700	9,300	41,700	73,200	0
5	As Filed - %		100.000%	60.877%	23.238%	1.189%	5.333%	9.362%	0.000%
6	Volume Change		0	1,100	-1,100	0	0	0	0
7	Increase/-Decrease (Ln. 3- Ln. 5)		0.000%	0.141%	-0.141%	0.000%	0.000%	0.000%	0.000%
8	COMPOSITE ALLOCATORS 1 & 3	5							
9	Corrected		100.000%	61.213%	23.975%	0.712%	4.328%	9.772%	0.000%
10	As Filed		100.000%	61.307%	24.120%	0.701%	4.258%	9.614%	0.000%
11	Increase/-Decrease (Ln. 9- Ln. 10)		0.000%	-0.094%	-0.145%	0.011%	0.070%	0.158%	0.000%
12	DITRIBUTION UNCOLLECTIBLES (Previously DIS Revenue)	7							
13	Corrected		100.000%	85.630%	13.666%	0.130%	0.235%	0.313%	0.026%
14	As Filed		100.000%	78.990%	21.010%	0.000%	0.000%	0.000%	0.000%
15	Increase/-Decrease (Ln. 13- Ln. 14)		0.000%	6.640%	-7.344%	0.130%	0.235%	0.313%	-0.026%
16	UNBUNDLED UNCOLLECTIBLES	23							
17	Corrected		100.000%	86.237%	13.763%	0.000%	0.000%	0.000%	0.000%
18	As Filed		100.000%	73.780%	26.220%	0.000%	0.000%	0.000%	0.000%
19	Increase/-Decrease (Ln. 17- Ln. 18)		0.000%	12.457%	-12.457%	0.000%	0.000%	0.000%	0.000%
20	MINIMUM SYSTEM MAINS	20							
21	Corrected		100.000%	82.841%	12.726%	0.335%	1.504%	2.594%	0.000%
22	As Filed		100.000%	82.938%	12.701%	0.329%	1.480%	2.552%	0.000%
23	Increase/-Decrease (Ln. 21- Ln. 22)		0.000%	0.097%	-0.025%	-0.006%	-0.024%	-0.042%	0.000%
24	DIRECT ASSIGNMENT - SERVICES	15							
25	Corrected - $		228,607,626	209,802,788	18,388,728	91,824	208,528	115,758	-
26	Corrected - %		100.000%	91.774%	8.044%	0.040%	0.091%	0.051%	0.000%
27	As Filed - $		262,823,185	240,345,517	21,856,197	191,151	295,258	135,062	-
28	As Filed - %		100.000%	91.448%	8.316%	0.073%	0.112%	0.051%	0.000%
29	Increase/-Decrease (Ln. 26- Ln. 28)		0.000%	0.326%	-0.272%	-0.033%	-0.021%	0.000%	0.000%
30	LARGE CUSTOMER RELATIONS	21							
31	Corrected # of Customers		157	-	18	2	39	88	10
32	Corrected - %		100.000%	0.000%	11.465%	1.274%	24.841%	56.051%	6.369%
33	As Filed # of Customers		157	-	18	41	-	88	10
34	As Filed - %		100.000%	0.000%	11.465%	26.115%	0.000%	56.051%	6.369%
35	Increase/-Decrease (Ln. 32- Ln. 34)		0.000%	0.000%	0.000%	24.841%	-24.841%	0.000%	0.000%
36	SALES AND CHOICE TRANSPORTATION	25							
37	Corrected Volume		43,479,194	32,785,788	9,700,922	931,484	-	-	61,000
38	Corrected %		100.000%	75.406%	22.312%	2.142%	0.000%	0.000%	0.140%
39	As Filed Volume		41,992,196	32,785,788	8,213,924	931,484	-	-	61,000
40	As Filed - %		100.000%	78.076%	19.561%	2.218%	0.000%	0.000%	0.145%
41	Increase/-Decrease (Ln. 38- Ln. 40)		0.000%	-2.670%	2.751%	-0.076%	0.000%	0.000%	-0.005%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: J.E. SKIRTICH

LINE NO.	ACCOUNT TITLE (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
1	Total Mains Plant in Service		911,044,198						
2	Less: Direct Mains Plant in Service		217,392	0	0	0	0	0	217,392
3	Allocable Mains Plant in Service		910,826,806						
4	Total All Pipe (376):		503,569,753						
5	Total All Pipe (376.30):		75,302,325						
6	Total All Pipe (376.80):		739,405						
7	Total All Pipe		579,611,484						
8	Percent Low Pressure greater than 2" gas Mains (pg. 2 ln. 3)		25.885%						
9	Low Pressure Non 2" Pipe		150,032,433						
10	Total 2" Pipe (376):		89,751,717						
11	Total 2" Pipe (376.30):		7,723,172						
12	Total 2" Pipe (376.80):		9,639						
13	Total 2" Pipe		97,484,528						
14	Total 2" Pipe and Non 2" Low Pressure Pipe (ln. 9 + ln. 13)		247,516,961						
15	Percentage of Total Acct 376 Pipe (ln. 14 / ln. 7)		42.704%						
16	Total Non-Pipe (ln. 3 - ln. 7)		331,215,323						
17	Percentage of Total Acct 376 Pipe (ln. 16)		42.704%						
18	Allocated Account 376 Non-Pipe (ln. 16 x ln. 17)		141,442,191						
19	**Total 2" Pipe and Non 2" Low Pressure Pipe & non Pipe (ln. 14 + ln. 18)**		**388,959,152**						
20	Design Day Volumes		65,770	47,710	18,060				
21	Percent Design Day		100.000%	72.541%	27.459%				
22	Throughput Volumes		46,129,238	32,785,788	13,343,450				
23	Percent Throughput		100.000%	71.074%	28.926%				
24	Composite Allocators ((line 21+ line 23 / 2)		100.000%	71.807%	28.193%				
25	**Allocated 2" Pipe and Non 2" Low Pressure Pipe**		**388,959,152**	**279,299,898**	**109,659,254**				
26	All Other Account 376 Plant in Service (ln. 3 - ln. 25)		**521,867,654**						
27	Design Day Volumes		781,900	477,100	180,600	9,300	41,700	73,200	
28	Percent Design Day		100.000%	61.018%	23.098%	1.189%	5.333%	9.362%	
29	Throughput Volumes		71,872,223	32,785,788	13,343,450	931,484	7,023,159	17,788,342	
30	Percent Throughput		100.000%	45.616%	18.566%	1.296%	9.772%	24.750%	
31	Composite Allocators ((line 28 + line 30) / 2)		100.000%	53.316%	20.832%	1.243%	7.553%	17.056%	
32	**Alloc All Other Acct 376 Plant in Service**		521,867,654	278,238,958	108,715,470	6,486,815	39,416,664	89,009,747	
33	**Total Alloc Account 376 Mains (ln 24 + ln 32)**		910,826,806	557,538,856	218,374,724	6,486,815	39,416,664	89,009,747	
34	**ALLOCATOR #5**		**100.000%**	**61.213%**	**23.975%**	**0.712%**	**4.328%**	**9.772%**	
35	As of September 15, 2012								
36	Low Pressure 2" or less gas Mains	2,357,866	5.998%						
37	Low Pressure greater than 2" gas Mains	10,176,303	25.885%						
38	Total Low Pressure gas Mains	12,534,169	31.883%						
39	Non Low Pressure	26,779,719	68.117%						
40	Total CPA gas Mains	39,313,888	100.000%						

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED JUNE 30, 2014

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: J.E. SKIRTICH

LINE NO.	ACCOUNT TITLE (A)	ALLOC (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
1	Total Mains Plant in Service		911,044,198						
2	Less: Direct Mains Plant in Service		217,392	0	0	0	0	0	217,392
3	Allocable Mains Plant in Service		910,826,806						
4	Total All Pipe (376):		503,569,753						
5	Total All Pipe (376.30):		75,302,325						
6	Total All Pipe (376.80):		739,405						
7	Total All Pipe		579,611,484						
8	Percent Low Pressure greater than 2" gas Mains (pg. 2 ln. 15)		25.885%						
9	Low Pressure Non 2" Pipe		150,032,433						
10	Total 2" Pipe (376):		89,751,717						
11	Total 2" Pipe (376.30):		7,723,172						
12	Total 2" Pipe (376.80):		9,639						
13	Total 2" Pipe		97,484,528						
14	Total 2" Pipe and Non 2" Low Pressure Pipe (ln. 9 + ln. 13)		247,516,961						
15	Percentage of Total Acct 376 Pipe (ln. 14 / ln. 7)		42.704%						
16	Total Non-Pipe (ln. 3 - ln. 7)		331,215,323						
17	Percentage of Total Acct 376 Pipe (ln. 16)		42.704%						
18	Allocated Account 376 Non-Pipe (ln. 16 x ln. 17)		141,442,191						
19	**Total 2" Pipe and Non 2" Low Pressure Pipe & non Pipe (ln. 14 + ln. 18)**		**388,959,152**						
20	Number of Customers		414,751	378,379	36,372				
21	Percent Customers		100.000%	91.230%	8.770%				
22	**Allocated 2" Pipe and Non 2" Low Pressure Pipe**		**388,959,152**	**354,847,434**	**34,111,718**				
23	All Other Account 376 Plant in Service (ln. 3 - ln. 22)		521,867,654						
24	Number of Customers		415,337	378,379	36,372	79	416	91	
25	Percent Customers		100.000%	91.102%	8.757%	0.019%	0.100%	0.022%	
26	Customer Component	51.76%		47.154%	4.533%	0.010%	0.052%	0.011%	
27	Design Day Volumes		781,900	477,100	180,600	9,300	41,700	73,200	
28	Percent Design Day Volumes		100.000%	61.018%	23.098%	1.189%	5.333%	9.362%	
29	Demand Component	48.24%		29.435%	11.142%	0.574%	2.573%	4.516%	
30	Minimum System Allocation Factor (ln 26 + ln. 29)			76.589%	15.675%	0.584%	2.625%	4.527%	
31	**Alloc All Other Acct 376 Plant in Service**		**521,867,654**	**399,693,217**	**81,802,755**	**3,047,707**	**13,699,026**	**23,624,949**	
32	**Total Alloc Account 376 Mains (ln. 21 + ln. 30)**		**910,826,806**	**754,540,651**	**115,914,473**	**3,047,707**	**13,699,026**	**23,624,949**	
33	**Composite Mains Allocation Factor**		**100.000%**	**82.841%**	**12.726%**	**0.335%**	**1.504%**	**2.594%**	

2" MINIMUM SYSTEM CALCULATION

		Footage	Amount	Unit Cost
34	Total 2" Pipe (376):	8,922,771	89,751,717	
35	Total 2" Pipe (376.30):	3,840,376	7,723,172	
36	Total 2" Pipe (376.80):	16,383	9,639	
37	Total 2" Pipe	12,779,530	97,484,528	$7.63
38	Total All Pipe (376):	21,307,190	503,569,753	
39	Total All Pipe (376.30):	17,715,858	75,302,325	
40	Total All Pipe (376.80):	295,811	739,405	
41	Total All Pipe [2]	39,318,859	579,611,484	
42	Unit Cost x Total All Pipe:		300,002,894	
43	Customer Component (Line 42 / Line 41):		0.5176	
44	Demand Component (1-Line 43):		0.4824	
45		TOTAL	1.0000	
46	As of September 15, 2012			
47	Low Pressure 2" or less gas Mains	2,357,866	5.998%	
48	Low Pressure greater than 2" gas Mains	10,176,303	25.885%	
49	Total Low Pressure gas Mains	12,534,169	31.883%	
50	Non Low Pressure	26,779,719	68.117%	
51	Total CPA gas Mains	39,313,888	100.000%	

[1] Customer Count excludes final bills.
[2] Does not tie directly to 376/376.30/376.80, due to inclusion of pipe only (not valves, labor, etc.).

Columbia Gas of Pennsylvania, Inc..
Comparison of Rates of Return from CCOSS - "As Filed" vs. "Corrected"

LINE NO.	DESCRIPTION (A)	ALLOC FACTOR (B)	TOTAL COMPANY (C)	RS/RDS (D)	SGS/SGDS (E)	LGS (F)	SDS (G)	LDS (H)	MDS (I)
1	**Customer Demand Study**								
2	Rate of Return earned on Rate Base - Corrected @ present rates		4.114%	2.329%	7.739%	15.013%	40.907%	34.012%	274.121%
3	Rate of Return earned on Rate Base - As Filed @ present rates		4.114%	2.358%	7.609%	8.367%	43.916%	34.618%	269.193%
4	Increase/-Decrease (Ln. 2 - Ln. 3)		0.000%	-0.029%	0.130%	6.646%	-3.009%	-0.606%	4.928%
5	Rate of Return earned on Rate Base - Corrected @ proposed rates		8.520%	6.541%	13.946%	22.763%	43.982%	34.049%	274.406%
6	Rate of Return earned on Rate Base - As Filed @ proposed rates		8.520%	6.560%	13.901%	15.934%	47.024%	34.655%	269.472%
7	Increase/-Decrease (Ln. 5 - Ln. 6)		0.000%	-0.019%	0.045%	6.829%	-3.042%	-0.606%	4.934%
8	**Peak & Average Study**								
9	Rate of Return earned on Rate Base - *Corrected @ present rates*		*4.114%*	*3.900%*	*3.030%*	*7.590%*	*11.788%*	*5.118%*	*274.121%*
10	Rate of Return earned on Rate Base - As Filed @ present rates		4.114%	3.934%	2.856%	3.450%	12.974%	5.277%	269.193%
11	Increase/-Decrease (Ln. 9 - Ln. 10)		0.000%	-0.034%	0.174%	4.140%	-1.186%	-0.159%	4.928%
12	Rate of Return earned on Rate Base - Corrected @ proposed rates		8.520%	8.947%	7.046%	12.550%	12.938%	5.128%	274.406%
13	Rate of Return earned on Rate Base - As Filed @ proposed rates		8.520%	8.965%	6.885%	8.357%	14.140%	5.287%	269.472%
14	Increase/-Decrease (Ln. 12 - Ln. 13)		0.000%	-0.018%	0.161%	4.193%	-1.202%	-0.159%	4.934%
15	**Average Study - Allocators 5 & 20**								
16	Rate of Return earned on Rate Base - Corrected @ present rates		4.114%	3.043%	4.880%	10.475%	19.715%	11.271%	274.121%
17	Rate of Return earned on Rate Base - As Filed @ present rates		4.114%	3.075%	4.711%	5.382%	21.419%	11.526%	269.193%
18	Increase/-Decrease (Ln. 16 - Ln. 17)		0.000%	-0.032%	0.169%	5.093%	-1.704%	-0.255%	4.928%
19	Rate of Return earned on Rate Base - Corrected @ proposed rates		8.520%	7.635%	9.756%	16.519%	21.389%	11.287%	274.406%
20	Rate of Return earned on Rate Base - As Filed @ proposed rates		8.520%	7.655%	9.624%	11.337%	23.115%	11.542%	269.472%
21	Increase/-Decrease (Ln. 19 - Ln. 20)		0.000%	-0.020%	0.132%	5.182%	-1.726%	-0.255%	4.934%

COLUMBIA GAS OF PENNSYLVANIA, INC.
REVENUE CHANGE AT SYSTEM AVERAGE FOR LDS - CORRECTED

Ln No.	DESCRIPTION	ACOS STUDIES CUSTOMER DEMAND SCHEDULE 1 (1)	PEAK & AVERAGE SCHEDULE 2 (2)	AVERAGE STUDY SCHEDULE 3 (3)
	"CORRECTED"			
1	OPERATING INCOME @ PROPOSED REVENUE	5,863,601	3,263,134	4,563,309
2	RATE BASE [PAGE 10]	17,221,274	63,637,166	40,429,327
3	RATE OF RETURN EARNED ON RATE BASE	34.049%	5.128%	11.287%
4	REQUESTED RATE OF RETURN ("ROR")	8.520%	8.520%	8.520%
5	OPERATING INCOME AT REQUESTED ROR (LN. 4 X LN. 2)	1,467,253	5,421,887	3,444,579
6	OPERATING INCOME SURPLUS/(DEFICIENCY) (LN. 1 - LN. 5)	4,396,348	(2,158,753)	1,118,730
7	GROSSUP FACTOR (EXHIBIT NO. 102, SCHEDULE 2)	1.73450116	1.73450116	1.73450116
8	SURPLUS (DEFICIENCY) REVENUE (LN. 6 X LN. 7)	7,625,471	(3,744,360)	1,940,438
	"AS FILED"			
9	OPERATING INCOME @ PROPOSED REVENUE	5,873,560	3,310,529	4,591,908
10	RATE BASE [PAGE 10]	16,948,685	62,616,057	39,783,380
11	RATE OF RETURN EARNED ON RATE BASE	34.655%	5.287%	11.542%
12	REQUESTED RATE OF RETURN ("ROR")	8.520%	8.520%	8.520%
13	OPERATING INCOME AT REQUESTED ROR (LN. 12 X LN. 10)	1,444,028	5,334,888	3,389,544
14	OPERATING INCOME SURPLUS/(DEFICIENCY) (LN. 9 - LN. 13)	4,429,532	(2,024,359)	1,202,364
15	GROSSUP FACTOR (EXHIBIT NO. 102, SCHEDULE 2)	1.73450116	1.73450116	1.73450116
16	SURPLUS (DEFICIENCY) REVENUE (LN. 14 X LN. 15)	7,683,029	(3,511,253)	2,085,502
17	Increase/-Decrease (Ln. 8- Ln. 16)	(57,558)	(233,107)	(145,064)

Columbia Gas of Pennsylvania, Inc.
System Charges Comparison - "Corrected" vs. "As Filed"

LINE NO.	ACCOUNT TITLE (A)	ALLOC (B)	TOTAL COMPANY (C) $	RS/RDS (D) $	SGS/SGDS (E) $	LGS (F) $	SDS (G) $	LDS (H) $	MDS (I) $
	With a Customer Component of Mains								
1	Corrected		34.82	32.04	51.76	493.21	403.89	2,725.00	1,135.91
2	As Filed		36.37	33.47	54.40	879.19	343.17	2,714.17	1,134.05
3	Increase/-Decrease (Ln. 1- Ln. 2)		(1.55)	(1.43)	(2.64)	(385.98)	60.72	10.83	1.86
	Without a Customer Component of Mains								
4	Corrected		17.56	16.43	25.59	177.42	146.15	757.94	772.48
5	As Filed		19.31	18.00	25.60	475.80	108.83	779.84	807.09
6	Increase/-Decrease (Ln. 4- Ln. 5)		(1.75)	(1.57)	(0.01)	(298.38)	37.32	(21.90)	(34.61)

COLUMBIA STATEMENT NO. 110-R

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

PAUL R. MOUL, MANAGING CONSULTANT
P. MOUL & ASSOCIATES, INC.

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Columbia Gas of Pennsylvania, Inc.
Rebuttal Testimony of Paul R. Moul
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INTRODUCTION

Q. Please state your name, occupation and business address.

A. My name is Paul R. Moul and I am Managing Consultant at the firm P. Moul & Associates. My business address is 251 Hopkins Road, Haddonfield, NJ 08033-3062.

Q. Mr. Moul, have you previously submitted direct testimony in this proceeding?

A. Yes. My direct testimony was submitted with the Company's case-in-chief on September 28, 2012 and was pre-marked as Columbia Statement No. 10.

Q. What is the purpose of your rebuttal testimony?

A. Columbia Gas of Pennsylvania, Inc. ("CPA" or the "Company") has requested that I review and respond to the testimony presented by Mr. Matthew I. Kahal, a witness appearing on behalf of the Office of Consumer Advocate ("OCA"), Ms. Emily Sears, a witness appearing on behalf of the Bureau of Investigation & Enforcement ("I&E"), and Mr. Robert D. Knecht, a witness appearing on behalf of the Office of Small Business Advocate ("OSBA").

Q. Have you prepared exhibits to accompany your rebuttal testimony?

A. Yes. Exhibit No. 400-R consisting of four (4) schedules was prepared by me to accompany my rebuttal testimony.

Q. Please identify the principal areas of controversy concerning the rate of return issue in this proceeding.

A. The appropriate cost of common equity for the Company represents the principal issue in dispute concerning rate of return. Ms. Sears concludes that the Company's proposed capital structure ratios are reasonable and consistent with the capital structure of her barometer group. Mr. Kahal has accepted several of the components of the Company's proposed capital structure, but he has improperly altered the Company's forecast of its common equity balance for the fully forecast test year ("FFTY"). Both witnesses have revised the Company's proposed cost of long-term debt. And indeed, a revision is required for the embedded cost of long-term debt based upon data that was not available at the time of the Company's filing. Ms. Sears and Mr. Kahal accept the cost rates associated with previous issues of the Company's long-term debt, but then re-price the new issues of debt scheduled to be issued later in 2013 and in 2014. Both witnesses propose a cost of short-term debt that is too low and will not adequately compensate Columbia for the cost that it pays for these funds. Even with these adjustments that require modifications that I discuss below, changes in the capital structure and cost of debt lowers the Company's overall rate of return by 0.13% and 0.08%, respectively, excluding disputes arising from the cost of equity. As a consequence, the major issue concerning the rate of return in this case is the cost of common equity recommended by the OCA and I&E witnesses, which are far too low.

Q. What explains the substantial disparity between the recommendations of the OCA and I&E and your proposed equity allowance?

A. The costs of equity proposed are summarized below.

CPA (Moul)	11.25%
OCA (Kahal)	9.50%
I&E (Sears)	8.51%

It is noteworthy that the cost of equity proposed by Ms. Sears is so low that it is of no value and not worthy of consideration by the Commission in setting the Company's rate of return in this proceeding. Ms. Sears' proposal is simply outside of the reasonable range of the cost of equity. And apparently, she has not incorporated the types of considerations that the Commission has employed in its recent rate case decision for PPL Electric Utilities Corporation. In contrast, Mr. Kahal provides a range of equity returns that encompasses 10.2% at the upper bound. This return at least borders on a reasonable proposal. The differences that contribute to the cost of equity proposals are attributable to a number of factors, including: (i) the determination of a reasonable Discounted Cash Flow (DCF) growth rate, (ii) whether a leverage adjustment to the DCF is necessary, (iii) the extent to which methods other than the DCF provide a reasonable measure of the appropriate cost of common equity and (iv) adequate recognition of the Company's higher risk. There is also an issue related to the composition of the proxy group employed by Ms. Sears, but it alone does not explain the significant difference in her proposed equity allowance. The

management performance allowance is another item that helps explain the difference in the positions of the parties.

Q. In discussing the growth rate component of the DCF model, Ms. Sears makes the observation that the natural gas industry is at an "inflection point." Do you agree with her observation?

A. Yes. Ms. Sears correctly observes that historically the natural gas utilities have had a stable rate of capital expenditures. Now however, much of its infrastructure is reaching the end of its useful life and requires replacement. This means that construction expenditures for the natural gas utilities will ramp-up and that new, more costly, infrastructure will replace heavily depreciated older assets. This also means that rate base will increase more rapidly in the future. There are several financial implications associated with this situation. One is that the industry requires a more robust financial profile in order to attract the capital from investors that it needs to finance these higher capital expenditures. This issue was covered in my direct testimony where it was revealed that Columbia will increase its net property, plant and equipment by 90% over the next five years (see page 9 of Columbia Statement No. 10). To accomplish the financing necessary to complete this construction, supportive economic regulation is required that includes a reasonable return on equity, a balanced capital structure, and higher levels of internally generated funds. Unfortunately, the cost of equity proposed by Ms. Sears will not accomplish these goals, other than her endorsement of the Company's common equity ratio.

While Ms. Sears acknowledges that the resulting increase in rate base will lead to growth in earnings that will exceed historical experience, she has not reflected this fact in her cost of equity proposal in this case.

CAPITAL STRUCTURE AND COST OF DEBT

Q. Ms. Sears has accepted the Company's proposed capital structure ratios and Mr. Kahal has made modifications to the Company's proposal. What changes has Mr. Kahal proposed?

A. Mr. Kahal has proposed a modification to the Company's capital structure related to the balance of common equity at the end of the fully forecast test year. Mr. Kahal claims that the balance of common equity is overstated because it assumes an unrealistic forecast, at least in his view, of the Company's future retained earnings. Mr. Kahal asserts that for the Company to achieve its retained earnings balance that it would need to achieve a 12% return yearly on its common equity. He then re-computes the Company's fully forecast test year balance of retained earnings with a lower assumed yearly return.

Q. What is wrong with Mr. Kahal's proposed modification?

A. Mr. Kahal used a simplistic approach to calculate the assumed return on equity for the projected years in the rate case. He assumed $50 million of net income per year based on the total increase in retained earnings of $100 million. He then used a beginning equity balance in each of his calculations. This approach produced slightly higher returns and Mr. Kahal rounded up to 12%. As stated in Mr. Kahal's direct testimony, Mr. Moul's Schedule 2 shows that CPA's return on

equity during the previous five years ranged from about 9 to 11 percent, with the exception of one year when it was nearly 15 percent. To be consistent with the calculations used in Schedule 2, I have recalculated the returns for the projected periods of May 31, 2013 and June 30, 2014 in the table provided below. It should be noted that the June 2014 return used by Mr. Kahal contains 13 months of net income due to the timing of the fully forecast test year. Therefore, it is necessary to divide the total net income by 13 and then multiply it by 12 months, to derive the average twelve month net income of $49,603 to be used to determine an annual return rate. Based on the same calculation used in Schedule 2, the returns implicit in the projection of retained earnings are very much in line with the historical returns that CPA has been earning.

	(000's)	Kahal's May 2013	TME May 2013	Kahal's June 2014	13 Month Ended June 2014	TME Avg June 2014
1	Net Income	$ 50,000	$ 46,514	$50,000	$ 53,737	$ 49,603
2	Dividend (paid 12/2012)		(1,000)			
3	Beginning Equity Balance	410,025	410,025	455,539	455,539	455,539
4	Ending Equity Balance		455,539		509,276	509,276
5	Average Equity Balance		432,782		482,408	482,408
6	Rate of Return on Book Common Equity	12.2%	10.7%	11.0%	11.1%	10.3%

Further, based upon the 10.4% equity return rate granted to PPL Electric Utilities by the Commission recently, the return rates shown above are entirely achievable with the opportunity provided by the Commission to Pennsylvania utilities.

Q. Both Mr. Kahal and Ms. Sears re-price the coupon rates for the issues of new long-term debt. Do you agree with their proposal?

A. I do in part. As a preliminary matter, it is necessary to update the Company's embedded cost of long-term debt for the new issue of long-term debt that was placed shortly after the case-in-chief was filed. The actual rate for this issue was 5.26% on November 28, 2012 vs. the 5.45% rate that was estimated in the Company's filing. Additional revisions are necessary for future issues forecast for May 31, 2013, December 31, 2013, and June 30, 2014. Those rates are 5.70%, 5.74% and 5.77%, respectively. All of these updates actually increase slightly the Company's fully forecast test year embedded cost of long-term debt to 5.81% from 5.80% that was used in the original filing. The updated cost of debt for the fully forecast test year is shown on Schedule 2 of Exhibit No. 400-R. Details of the rates applicable to each of the debt financing are revealed on Schedule 3 of Exhibit No. 400-R. These data reveal that the changes in the embedded cost of debt proposed by Mr. Kahal and Ms. Sear are too low. The Company's cost of debt is calculated in accordance with the Securities Certificate obtained from the Commission. It should be noted that the cost of debt calculated with the spread related to the BBB-rating is not just attributable to the capital structure. The

affiliation that CPA has with NiSource should not result in a penalty because the Company's membership in the NiSource family provides many benefits. CPA would not have high credit quality on its own, if it were a standalone company.

As to the cost of short-term debt, the Blue Chip Financial Forecast dated January 1, 2013 shows a forecast LIBOR rate of 0.375% for the fully forecast test year.[1] With the 147.5 basis points spread on borrowings from the NiSource money pool, the resulting cost of short-term debt is 1.85% (0.375% + 1.475%). The spread of 147.5 bps over LIBOR represents the Company's cost of short term revolving loans per the NiSource Finance Corporation $1.5 billion revolver agreement. The current revolver agreement was dated May 15, 2012 and terminates on May 15, 2017. Please note that the interest rate spread is based upon the NiSource credit rating of BBB- by S&P or Baa3 by Moody's. This small change together with the re-pricing of the Company's long-term debt shown on Schedule 2 of Exhibit No. 400-R indicate no net change in the 5.51% cost of debt (i.e., long-term and short-term) for the fully forecast test year. The new debt cost rates have been carried over to Schedule 1 of Exhibit No. 400-R, which shows no change in the Company's overall rate of return for the fully forecast test year.

[1] The LIBOR rates are 0.3% for the third quarter of 2013, 0.4% for the fourth quarter of 2013, 0.4% for the first quarter of 2014, and 0.4% for the second quarter of 2014. The four quarter average is 0.375% (0.3% + 0.4% + 0.4% + 0.4% = 1.5% ÷ 4).

OSBA PROPOSAL

Q. Have you reviewed the testimony of Mr. Knecht as it relates to his cost of equity proposal?

A. Yes. Mr. Knecht did not submit an independent analysis of the cost of equity. Instead, he opines that the Company's rate of return on common equity should be no higher than 10%. He bases his proposal using the Morningstar Equity Cost Analysis, returns awarded by the regulators in other rate case decisions, and recent Commission decisions in other rate case proceedings.

Q. Please comment on the usefulness of the Morningstar Equity Cost Analysis for setting the Company's rate of return on common equity.

A. Based on my review of information provided by Mr. Knecht, there is inadequate data provided concerning the Morningstar Cost of Equity Yearbook to justify reliance upon these data to set the Company's cost of equity. For example, Mr. Knecht says that due to copyright issues he cannot reveal particulars from Morningstar Cost of Equity Yearbook concerning: (i) the procedures used to measure the cost of capital, (ii) capital structure issues related to the cost of capital (iii) the results of each cost of capital model applicable to SIC 4924, Natural Gas Distribution, (iv) the identities of each component of the group that represents SIC 4924, (v) the input values used for each method employed to measure the cost of capital for SIC 4924, (vi) the time period employed to assemble the input values for SIC 4924, (vii) the results of each model of the cost of capital applicable individually for the companies in SIC 4924, (viii) the

individual input values for each factor (i.e., first-stage growth, second-stage growth, and third-stage growth of the DCF model) for each company that comprise SIC 4924. The absence of any details provided by Mr. Knecht from the Morningstar Cost of Capital Yearbook does not allow the verification of the summary statistics relied upon by Mr. Knecht. The data he submits in this regard simply cannot be used as a guide to set the Company's cost of equity in this case.

Q. Do the returns provided on figure IEc-2 support a return for the Company over 10%?

A. Yes. Mr. Knecht's table provides the data to calculate an average authorized return of 10.27% (10.50% + 10.28% + 10.19% + 10.10% = 41.07% ÷ 4) for all energy utilities and 10.15% for gas utilities (10.44% + 10.26% + 9.98% + 9.92% = 40.60% ÷ 4). These returns and their associated ranges show that the cost of equity proposals by Mr. Kahal and Ms. Sears are clearly out of the mainstream of authorized returns.

Q. How do these recommendations compare to the most recently authorized cost of equity determined by the Commission?

A. The Commission provided a 10.40% return on equity (including recognition of management performance) in its Order entered December 28, 2012 at Docket No. R-2012-2290597 for PPL Electric Utilities Corporation. Hence, Mr. Knecht's position that 10% forms some type of ceiling for the return on equity is misplaced.

COMPARABLE COMPANIES

Q. Have proxy groups of companies been employed in this case to determine the Company's cost of equity?

A. Yes. Mr. Kahal, Ms. Sears and I have used proxy groups of companies to measure the cost of equity for CPA. Mr. Kahal and I have used the exact same companies in our respective proxy group. However, Ms. Sears has erroneously deleted South Jersey Industries and WGL Holdings from her group. Ms. Sears' reasoning for ignoring South Jersey Industries and WGL Holdings is based on her mistaken belief that their low percentage of revenues from gas utility operations disqualifies them from her proxy group. But the revenue percentage is the wrong criteria for assessing the eligibility of a company in the proxy group.

Q. Please explain why the percentage of revenues devoted to utility operations is an inappropriate criterion for excluding South Jersey Industries and WGL Holdings from the proxy group.

A. For natural gas companies, revenues cannot be used for selection purposes because the margins on other business segments are generally dissimilar to the gas distribution business. Energy trading is a case in point, which would make revenue comparisons incompatible because of the small margins associated with that business. That is to say, energy trading generates large amount of revenues, but little profits because the margins on such trades are very small. The correct screening criterion is the percentage of gas assets to total assets and related percentage of gas income to total income because they best describe the amount

of capital that a firm devotes to each business segment and the return achieved on such assets.

Q. What are the business segment data for South Jersey Industries?

A. Those data are presented below:

	Gas Utility		
	Revenues	**Income**	**Assests**
South Jersey Industries	49.78%	84.42%	71.89%
WGL Holdings	46.91%	78.66%	85.53%

From the data shown above, both South Jersey Industries and WGL Holdings are valid candidates for inclusion in the proxy group because 79% to 84% of income and 72% to 86% of assets are devoted to gas utility operations. This shows that the revenue selection criteria selected by Ms. Sears provides a misleading gauge of the relative importance of the gas utility business segment.

DISCOUNTED CASH FLOW

Q. Ms. Sears appears to rely extensively and arguably exclusively, on the DCF method. Do you agree with this approach?

A. No, I do not. While the results of a DCF analysis should certainly be given considerable weight, the use of more than one method provides a superior foundation for the cost of equity determination. This is particularly true today, with the wide swings in share values and the overall financial market uncertainty experienced recently. This means that the risk of common stocks is high, and the cost of equity determined in this proceeding should reflect this fact. Since all

cost of equity methods contain certain unrealistic and overly restrictive assumptions, the use of more than one method will capture the multiplicity of factors that motivate investors to commit capital to an enterprise (i.e., current income, capital appreciation, preservation of capital, level of risk bearing, etc.). For that reason, I disagree with Ms. Sears' approach, which appears to rely almost exclusively on the DCF method (she cites the results of a CAPM analysis, but only as confirmatory evidence of the reasonableness of her DCF findings).

Q. Do the DCF results proposed by Ms. Sears provide a reasonable representation of the cost of equity?

A. No, they do not. As indicated below, I have disaggregated Ms. Sears' DCF analysis showing the calculations separately for several of the companies in her barometer group.

Company		Average: 52 wk & Spot Yield	+	Growth	=	Total
AGL RES INC (GAS)		4.80%	+	2.95%	=	7.75%
LACLEDE GROUP INC (LG)		4.32%	+	3.45%	=	7.77%
NEW JERSEY RES (NJR)		3.68%	+	3.98%	=	7.66%

I should note that the 7.75% DCF result shown for AGL Resources, the 7.77% DCF result shown for Laclede Group, and the 7.66% DCF result shown for New Jersey Resources are totally unrealistic because they provide an insufficient spread over the yield of 4.96% on A-rated public utility bonds that she presents on page 2 of Schedule 2 of I&E Exhibit No. 1. The cost of equity must be higher

than the cost of debt by a meaningful margin to compensate for the higher risk associated with a common equity investment.

Q. Ms. Sears also challenges the ex-dividend adjustment that you made in calculating your dividend yields. Please comment.

A. First, and contrary to Ms. Sears' belief, there has been extensive academic research on the impact of the ex-dividend on stock prices. In fact, I am aware of numerous academic studies that indicate that stock prices react to the ex-dividend date[2].

Second, Ms. Sears claims that there is no evidence to suggest that investors make this adjustment. This assertion again is incorrect because the Securities and Exchange Commission ("SEC") has alerted investors to the significance of the ex-dividend adjustment, stating:

> "With a significant dividend, the price of a stock may move up by the dollar amount of the

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[2]Avner Kalay, "The Ex-Dividend Day Behavior of Stock Prices: A Re-examination of the Clientele Effect," Journal of Finance, 37 (September 1982), 1059-70; Keneth M. Eades, Patrick J. Hess, and E. Han Kim, "On Interpreting Security Returns During the Ex-Dividend Period," Journal of Financial Economics, 13 (March 1984), 3-34; Patrick J. Hess, "The Ex-Dividend Day Behavior of Stock Returns: Further Evidence on Tax Effects," Journal of Finance, 37 (May 1982), 445-56: James M. Poterba and Lawrence H. Summers, "New Evidence That Taxes Affect the Valuation of Dividends." Journal of Finance, 39 (December 1984), 1397-1416; Michael Barclay, "Tax Effects with No Taxes? Further Evidence on the Ex-Dividend Day Behavior of Common Stock Prices," working paper, Stanford University (September 1984); and Costas P. Kaplanis, "Options, Taxes, and Ex-Dividend Day Behavior," Journal of Finance, 41 (June 1986), 411-24.

See Kalay, "The Ex-Dividend Day Behavior of Stock Prices"; Jerry Green, "Taxation and the Ex-Dividend Day Behavior of Common Stock Prices" working paper. National Bureau of Economic Research, Cambridge, Mass (1980); and Hess, "The Ex-Dividend Day Behavior of Stock Returns." Black and Scholes, "The Effects of Dividend Yield and Dividend Policy on Common Stock Prices and Returns."

Miller and Scholes, "Dividends and Taxes." See Marshall Blume, "Stock Returns and Dividend Yields: Some More Evidence." Review of Economics and Statistics, 62 (November 1980), 567-77.

Edwin J. Elton and Martin J. Gruber, "Marginal Stockholder Tax Rates and the Clientele Effect," Review of Economics and Statistics, 52 (February 1970), 68-74.

> dividend as the ex-dividend date approaches and then fall by that amount after the ex-dividend date. A stock that has gone ex-dividend is marked with an "x" in newspapers on that day."
> http://www.sec.gov/answers/dividen.htm

Third, Ms. Sears claims that she is unaware of any financial publications that provide ex-dividend adjusted yields. However, the ex-dividend dates are routinely reported in the financial press and are widely available on the internet. Moreover, the Barron's source that Ms. Sears has used for her stock prices, as well as The Wall Street Journal, both provides a list of stocks that trade ex-dividend. In fact, while there is a change in the price of stock equal to the amount of the dividend payment when the stock trades without its dividend on the ex-dividend date, there is no net change from the prior day's stock price shown in the daily change column. The Wall Street Journal signifies the lack of pricing change related to the dividend by the "x" notation in its stock listings. In short, I am confident that investors are well aware of when stocks trade ex-dividend and take that into account in their decisions to buy or sell.

I should further observe that Ms. Sears has used an unconventional method of computing her dividend yields. On Schedule 5 of I&E Exhibit No. 1, Ms. Sears apparently failed to employ the conventional approach of adjusting her dividend yields with the formula $D_0/P_0 (1 + .5g)$. Yet, she did so as revealed in footnote (b) on page 1 of Schedule 10 of I&E Exhibit No. 1. She is inconsistent in this regard when she makes the adjustment on page 1 of Schedule 10 of I&E Exhibit No. 1 in performing a DCF in calculating total market returns to be used

in the CAPM and does not do so on Schedule 5 of I&E Exhibit No. 1 in her DCF analysis.

Q. Please summarize the DCF growth rate analysis performed by Ms. Sears.

A. On page 1 of Schedule 7 of I&E Exhibit No. 1, Ms. Sears presents the type of earnings growth rate forecasts that are traditionally used in the DCF analysis and that average 4.35%. However, this average includes a negative growth rate for AGL Resources. This negative growth rate must be removed because it is not reflective of the positive growth that investors expect for AGL Resources and is inconsistent with the positive growth rates for AGL Resources published by MSN Money, Morningstar and Value Line shown on that schedule. As I will discuss below, Mr. Kahal correctly recognized the anomaly of the AGL Resources growth rate published by Yahoo!Finance in performing his analysis. Ms. Sears failed in this regard. After removing the anomalous negative growth rate by Yahoo!Finance for AGL Resource the resulting average for AGL is 5.83%, and the Barometer Group average is 4.85%.

Q. On pages 27 and 28 of her testimony, Ms. Sears expresses her concern about using analysts' forecasts of earnings per share growth used in the DCF model. Do you agree?

A. No, I do not. Ms. Sears' direct testimony is contradictory on this issue. Indeed, Ms. Sears uses analysts' forecasts extensively in her DCF analysis. And in fact, if investors are placing reliance on an analysts' forecast of growth, and indeed the

analysts' estimates are biased, then the prices of stocks will be overstated if investors rely upon those estimates. So if Ms. Sears is correct in her assessment that analysts' growth forecasts, stock prices would have to be adjusted downward and thus dividend yields adjusted upwards to accommodate the bias. Failure to make these adjustments would result in a mis-specified cost of equity. The study that Ms. Sears relies upon compares actual earnings and forecasts of earnings. Many things happen between the forecast and actual results, which does not mean that analysts' forecasts are not used by investors to set cost of equity. As opposed to the position taken by Ms. Sears that analysts' forecasts overstate actual earnings growth, The Wall Street Journal article dated April 26, 2010, reported that 64% of companies have beaten the analysts' forecasts since the start of 1999. This means that over the past decade analysts were actually too conservative in their forecasts.

Q. And based upon her discussion of the inflection point that currently affects the natural gas industry, how does this impact the selection of the growth rate in the DCF model?

A. With the trend toward more investment and consequently higher earnings for the future, growth rates toward the upper end of the range of analysts' projected growth rates would accommodate the new reality associated with the inflection point. Hence, the growth rate that will accommodate the inflection point would be at the upper end of the analysts' forecasts reported by Ms. Sears. The range of analysts' forecasts is 3.45% to 6.06% after correcting for anomalous growth rate

for AGL Resources that I described above. The midpoint of the top half range is 5.41%.

Q. What DCF return is indicated with the 5.41% to 6.06% growth rates correcting for the error in the AGL Resources growth rate?

A. By combining the 4.07% dividend yield calculated by Ms. Sears without the traditional adjustment of D_0/P_0 (1 + .5), the 5.41% and 6.06% growth rates, and my leverage adjustment, I derive the following results:

	D/P	+	*g*	=	*k*	+	*lev.*	=	*K*
52-Week and Spot	4.07%	+	5.41%	=	9.48%	+	0.64%	=	10.12%
52-Week and Spot	4.07%	+	6.06%	=	10.13%	+	0.64%	=	10.77%

But of course, the DCF misses the true cost of equity because it ignores South Jersey Industries and WGL Holding that is revealed in the analysis by Mr. Kahal. The DCF return shown above also would require further adjustment to account for the higher risk of CPA compared to the gas barometer group.

Q. Mr. Kahal relies on analysts' growth rate forecasts, but states that they should be subject to a reasonableness test and corroboration. Do the other measures of growth considered by Mr. Kahal for this purpose provide useful information in the context of the DCF growth rate?

A. No. Along with analysts' forecasts, Mr. Kahal uses other measures of growth published by Value Line. They include dividend per share growth, book value per share growth, and earnings retention growth. It must be remembered that

the theory of the DCF holds that (1) the value of a firm's equity (i.e., share price) will grow at the same rate as earnings per share with a constant P-E ratio and (2) dividend growth will equal earnings growth with a constant payout ratio. Therefore, to properly reflect investor expectations within the limitations of the DCF model, earnings per share growth, which is the basis for the capital gains yield and the source of dividend payments, must be given greatest weight. The reason that earnings per share growth is the primary determinant of investor expectations rests with the fact that the capital gains yield (i.e., price appreciation) will track earnings growth with a constant price earnings multiple (a key assumption of the DCF model). It is also important to recognize that analysts' forecasts significantly influence investor growth expectations (see Appendix E -- pages E-6 through E-10). Moreover, it is instructive to note that Professor Myron Gordon, the foremost proponent of the DCF model in public utility rate cases, has established that the best measure of growth for use in the DCF model are forecasts of earnings per share growth.[3] The bottom line is that Professor Myron Gordon has established that analysts' growth forecasts are the best measure of investor expectations in the DCF model.

Q. Have you detected any anomalies with the analysts' forecasts of earnings growth presented on page 3 of Schedule MIK-4?

A. Yes. As noted above, the negative growth rate published by Yahoo for AGL Resources is an obvious anomaly. It is certainly an outlier that should be

[3] "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management, Spring 1989 by Gordon, Gordon & Gould.

excluded because it is incompatible with the other forecasts for AGL Resources, especially the 6.0% growth rate published by Value Line and the other positive growth rates. For this reason, Mr. Kahal correctly excluded the Yahoo growth rate for AGL Resources as he noted in the footnote on page 3 of Schedule MIK-4.

Q. As part of his DCF analysis, Mr. Kahal has provided dividends per share growth rates published by Value Line. Are these growth rates useful in the DCF?

A. Not at this time. As I explain in my direct testimony, with the constant growth assumption of the DCF model, dividends per share will grow in the long-run at the same rate as earnings per share yielding a constant dividend payout ratio, and the stock price will grow in the long-run at the same rate as earnings per share yielding a constant price-earnings multiple. However, the forecasts shown below indicate that dividend per share growth will lag earnings growth because the dividend payout ratio is projected to decline.

Payout Ratios

	2012	2013	2015-17
AGL RES INC (GAS)	65%	58%	52%
ATMOS ENERGY CORP (ATO)	65%	59%	54%
LACLEDE GROUP INC (LG)	60%	61%	55%
NEW JERSEY RES (NJR)	56%	53%	49%
NORTHWEST NAT GAS CO (NWN)	80%	75%	62%
PIEDMONT NAT GAS INC (PNY)	74%	72%	73%
SOUTH JERSEY INDS INC (SJI)	52%	52%	52%
SOUTHWEST GAS CORPORATION (SWX)	44%	45%	42%
WGL HOLDINGS INC. (WGL)	59%	65%	64%
Average	62%	60%	56%

The above-referenced forecast decline in dividend payout ratios for the natural gas barometer group tells us two things. As Ms. Sears noted, the natural gas industry is at an inflection point and due to the ramp-up of construction spending, an increase in the internally generated funds for construction are a reflection of lower dividend payout ratios. Second, earnings per share growth are the correct focus in the DCF model. The Value Line growth rates in dividends per share shown on pages 4 of Schedule MIK-4 should be given no weight because they understate the growth rate in the context of a declining dividend payout ratio..

Q. Mr. Kahal also presents information concerning earnings retention growth. Please comment.

A. The earnings retention growth rates as shown on page 5 of Schedule MIK-4 are understated because of Mr. Kahal's reliance on the Value Line source, which are calculated with year-end values, rather than average book values. Value Line

defines "return on equity," which forms the basis of earnings retention growth after payment of common dividends, as follows:

> Percent Earned Common Equity – net profit less preferred dividends divided by common equity (i.e., net worth less preferred equity at liquidation or redemption value), expressed as a percentage. See Percent Earned Total Capital.

Without an adjustment to convert the Value Line forecasts from year-end to average book values, there is a downward bias in the results. This is because with an increasing book value driven by retention growth, the average book value will be less than the year-end book value. For that reason, the Federal Energy Regulatory Commission ("FERC") adjusts the year-end returns to derive the average yearly return, using the formula 2 (1 + G) / (2 + G) (see 92 FERC ¶ 61,070). Generally speaking, this adjustment increases the earnings retention growth. I have used a variant of the FERC's adjustment procedure to detect any downward bias in the figures reported by Mr. Kahal. I have reported the results of my analysis on Schedule 4 of Exhibit No. 400-R. Here, the use of the average book value in the calculation provides an 11.81% forecast return on average book common equity, rather than the 10.8% return on year-end book value, which is also shown on Schedule 4 of Exhibit No. 400-R. And, Mr. Kahal never explains how the Gas Group could achieve either the 10.8% return on book equity reported by Value Line on year-end book value, or the 11.81% equity return on average book value if their cost of equity was set at 9.5% using the DCF model.

Overall, the "br" growth rate indicates a 6.18% growth rate using average book value.

Q. Mr. Kahal notes the various similarities in the application of the DCF in both his testimony and your direct testimony and states that you use analysts' projections of earnings growth exclusively. Please respond.

A. I did not ignore other data (e.g., dividend growth, book value growth) in the development of my 5.25% investor expected growth rate, as a review of Exhibit No. 400 indicates. Moreover, the forecast earnings growth rates that I relied on encompass all factors that cause earnings per share to increase, including both internal and external factors.

Q. What DCF results are suggested by Mr. Kahal's analysis?

A. I have recalculated his DCF results below. The growth rate that I have used in this calculation is the 6.12% growth rate provided on Schedule 4 of Exhibit No. 400-R. I have also included the leverage adjustment, which I developed in my direct testimony.

	D_1/P_o	+	g	=	k	+	$lev.$	=	K
Kahal Gas Group	3.8%	+	6.12%	=	9.92%	+	0.64%	=	10.56%

The DCF return shown above is without the upward adjustment to recognize the higher risk of Columbia.

LEVERAGE ADJUSTMENT

Q. Please respond to the opposing party witnesses' criticism of your leverage adjustment.

A. Mr. Kahal claims that my leverage adjustment has nothing to do with the market-determined cost of capital and represents an attack on traditional cost-based ratemaking. I disagree. In order to make the DCF results relevant in the ratemaking context, the market-derived cost rate cannot be used without modification. If the market-determined cost of equity is applied to a capital structure, such as that traditionally utilized for ratemaking purposes, that is based on book values and not market values, then the financial risk associated with the cost of equity is changed and the leverage modification is necessary. The point of the leverage adjustment is to synchronize the market-determined cost of equity with the book value capital structure used in traditional cost-based ratemaking. That is to say, the leverage adjustment that I have proposed provides a bridge to span the gap between the two capital structures, and is not an attack on traditional cost-based ratemaking.

Q. On page 47 of his direct testimony, Mr. Kahal attempts to link the issue of a market-to-book relationship with your leverage adjustment. Is this correct?

A. No. Market-to-book ("M/B") ratios are entirely irrelevant to my leverage adjustment. The leverage adjustment contains no factor that would express the DCF return for any particular market-to-book ratio. Rather, it is a financial risk

adjustment that mathematically accounts for differences in capital structure ratios. I must once again make it clear that my leverage adjustment is not intended to achieve, and contains no factor for, a particular market-to-book ratio. Rather, it merely expresses the cost of equity as the unleveraged return plus compensation for the additional risk of introducing debt and/or preferred stock into the capital structure. The return for the Gas Group applicable to its equity with no debt in its capital structure (i.e., the cost of capital is equal to the cost of equity with a 100% equity ratio) is 7.94% (see page E-11 of Appendix E). To this, I add 1.84% compensation for the Group's average 43.21% debt ratio, plus 0.01% for an average 0.17% preferred stock ratio. The sum of the parts is 9.79% (7.94% + 1.84% + 0.01%). I know of no means to mathematically solve for the 0.64% leverage adjustment which merely represents the difference in the 9.79% cost of equity determined from the formula described above and the simple yield plus growth form of the DCF (i.e., 9.79% - 9.15% = 0.64%) by expressing it in the terms of any particular relationship of market price to book value. That is to say, the 0.64% adjustment is merely a convenient way to compare the 9.79% return computed directly with the Modigliani & Miller formulas to the 9.15% return generated by the DCF model based on D/P + g. There can be no dispute that a firm's financial risk varies with the relative amount of leverage contained in its capital structure. Note that the barometer group DCF cost rate must be adjusted for Columbia greater risk as I explain subsequently in this testimony and in my direct testimony.

Q. Please respond to Ms. Sears' criticisms of your leverage adjustment.

A. Ms. Sears offers five reasons for not using the leverage adjustment. First, Ms. Sears notes that the credit rating agencies assess financial risk in terms of the book value of debt in their analysis of the creditworthiness of a company. I agree. But this has nothing to do with my leverage adjustment. The credit rating agencies do not measure the market required cost of equity for a company. Hence, they are not concerned with the cost of equity or how it is applied in the ratesetting context. Rather, the credit rating agencies are only concerned with the interests of lenders and the timely payment of interest and principal by utilities. Hence, Ms. Sears' observation regarding the rating agencies is not on point for the leverage adjustment.

Q. Second, Ms. Sears also questions your leverage adjustment by reference to several prior Commission orders. Please comment.

A. Initially, she cites to a Blue Mountain decision, which is now over 30 years old and, more importantly, was litigated in an environment that is distinguishable in a number of critical respects. For example, that case was not decided using the DCF method. Rather, the Commission relied heavily on earnings/price ratios to set the return on equity in the context of a fair value rate base. Moreover, in its decision on remand, the Commission noted that over a period of years it was relatively easy to discern the trends in market-to-book ratios which, when compared to performance as measured by other financial ratios, can indicate the return levels the Commission must award to assure reasonable access by public

utilities to the capital markets. Notably, the trends in market-to-book ratios during that period were substantially different from today. At the time that case was litigated, market-to-book ratios for the broader market generally approximated 1:1. That is to say, market prices in the late 1970s were about equal to book value. Since that time, share prices have moved much higher vis-à-vis their underlying book values. So, while the market-to-book ratio of the DJI approximated 1:1 in the late 1970s, today the DJI trades at about 2.95:1 of book value. In short, the capital markets today are markedly different than those that existed at the time of the Blue Mountain case. I should also note that, since that time, the Commission has adopted my leverage adjustment to the DCF model on numerous occasions.

Ms. Sears also points to three relatively recent decisions where the Commission declined to make a leverage adjustment – i.e., rate cases involving Metropolitan Edison, Aqua Pennsylvania, and the City of Lancaster Water Department. It is my understanding that the adjustment proposed in the MetEd case is distinguishable and, as such, the Commission's rejection of it in the MetEd case has no bearing on my adjustment here. Moreover, after rejecting the adjustment proposed in the MetEd case, the Commission accepted my adjustment in a later case for PPL Gas Utilities Corporation at Docket No. R-00061398. The fact that the Commission declined to use the leverage adjustment in the Aqua Pennsylvania case cited by Ms. Sears similarly does not invalidate its use here. Notably, the Commission did not repudiate the leverage

adjustment in the Aqua Pennsylvania case, but instead arrived at an 11.00% return on equity for Aqua Pennsylvania including a separate return increment for management performance. As to the City of Lancaster decision, the approach taken there was quite different than the leverage adjustment that I propose in this case. Lancaster developed its recommended leverage adjustment based on the Hamada formula and applied it to the DCF result, the Risk Premium result, and the CAPM. While the Hamada formula plays a role in the CAPM, it is not applicable to the DCF or the Risk Premium measures of the cost of equity.

Q. Third, Ms. Sears says that your leverage adjustment lacks academic literature support. Please respond.

A. Leverage adjustments are routinely discussed in academic literature. Indeed, any basic finance textbook discusses the relationship between returns and the degree of financial leverage, and often references the work of Modigliani and Miller and Hamada. I have merely extended these well-accepted principles to the ratesetting process. Ms. Sears also comments on the citation that I made to pages from the text written by Roger A. Morin. Ms. Sears makes the irreverent comment that Dr. Morin's book is not peer reviewed. She offers no substantiation for this assertion and has not offered any evidence that the book which is published by Public Utilities Reports has any deficiencies or Dr. Morin is unqualified to author this widely regarded text on public utility regulation. She further observes that Dr. Morin discusses the Modigliani and Miller theories in the context of an optimal capital structure. But this provides no basis to

criticize my use of the leverage adjustment formula because the principles discussed by Dr. Morin apply to any capital structure, whether optimal or not. Finally, Ms. Sears provides a quote from Dr. Morin that says, "Therefore, the capital structure used to estimate the cost of equity is an integral inseparable part of that estimate." This is exactly what I have done through application of my leverage adjustment procedure.

Q. Fourth, Ms. Sears contends that your proposed leverage adjustment contains flaws related to the "ku" factor in the formula. Is she correct?

A. No. She referenced page E-11 of Appendix E to my direct testimony. In fact, the Microsoft Excel spreadsheet that was attached to my response to Interrogatory I&E-RR-14-D essentially refuted the points raised in Ms. Sears' testimony. As shown therein, the unlevered cost of equity (i.e., "ku") is solved in the equation by an iterative process that is no different than that used in standard financial formulas, such as the internal rate of return associated with the discounting of future cash flows (i.e., the foundation for the DCF model), or statistical analysis, such as solving for the slope of a regression equation. As such, Ms. Sears' claims that there is no source for the 7.94% cost of equity for a firm with 100% common equity is incorrect.

Q. Fifth, Ms. Sears argues that investors base their decisions on the book value debt and equity ratios for regulated utilities. Please respond.

A. Ms. Sears contends that information presented to investors, such as the Value Line data, argues against the leverage adjustment because investors base their investment decisions on book value. Yet Value Line also presents to investors the market capitalization of the equity for regulated utilities. I fundamentally disagree that investors base their decisions on book values. To the contrary, it is the future cash flows that investors expect to realize that determines the price they are willing to pay for a share of common equity. If the financial risk associated with the book value capital structure is different from the market value of the capitalization, that risk difference must be taken into account. Hence, her point here is irrelevant.

RELATIVE RISK OF CPA

Q. In proposing his rate of return on common equity, Mr. Kahal makes an adjustment for the risk of CPA as compared to the Gas Group. Do you agree with his adjustment?

A. Yes, in part. I agree with Mr. Kahal that an adjustment is necessary to the DCF results obtained from the Gas Group to account for the higher risk of CPA. But I completely disagree that such risk adjustment is linked entirely to the rate design issue. If the Company were to prevail in its rate design proposal in this case, a risk adjustment would continue to be warranted for reasons explained in my direct testimony. In my direct testimony (CPA Statement No. 9), I added 0.76% to the Gas Group results to account for the higher risk of CPA. I should note that using the difference in yields caused by variations in credit quality (i.e.,

A vs. Baa-rated bonds) represented a convenient way to quantify risk differences, but the Company's higher risk was not related solely to credit rating differences. Mr. Kahal added up to 0.40% to the results of his DCF to account for the higher risk of CPA. The midpoint of his range is 0.20%. So both Mr. Kahal and I are in agreement that an adjustment to the Gas Group results is necessary, the only question is the magnitude of the adjustment.

Q. Has Ms. Sears recognized the higher risk of CPA when proposing her rate of return on common equity?

A. No. Her proposal is deficient in this regard. There is just no question that CPA has higher risk than her gas barometer group. And, the availability of the DSIC is not a factor that will offset the Company's higher risk. Ms. Sears claims that my position is that the DSIC has no effect on risk. Rather, my position is that the effect of the DSIC is already reflected in the cost of equity as measured by the Barometer Group, and that no additional consideration of the DSIC is required. I say this because five/six members of her gas barometer group (e.g. AGL Resources, Atmos Energy, Laclede, New Jersey Resources, and Northwest Natural Gas, while Southwest Gas has a more limited infrastructure recovery mechanism) have infrastructure mechanisms that provide benefits similar to the DSIC. Since those benefits are already reflected in the common stock prices of those companies, there is no need to further consider the effects of the DSIC on the cost of equity. In addition, all but one member of her gas barometer group have revenue decoupling mechanisms ("RDM"), and the remaining company

(i.e., Laclede Group) has a rate structure that is designed to mitigate the effects of variations in usage associated with the influence of weather. CPA has no RDM mechanism or weather mitigated rate design, which elevates the Company's risk, as compared to the barometer group. And most importantly, CPA has a service territory that overlaps with other LDCs in western Pennsylvania. CPA is faced with competitive threats unlike any of the companies in her gas barometer group. This creates significant risk for CPA that elevates its risk above the gas barometer group employed by Ms. Sears. To recognize the higher risk of CPA, an upward adjustment is required to the Company's cost of equity.

CAPITAL ASSET PRICING MODEL

Q. Mr. Kahal has objected to the market premium that you used in the CAPM. Please comment.

A. Mr. Kahal used a market premium ("Rm-Rf") of 5.0% to 8.0%, while I used a figure of 8.99%. So at the top of Mr. Kahal's range, there is not much difference between his proposal and mine. And, in his "high sensitivity" case where he uses 9.0%, he is using a market premium that essentially equals mine. Unlike Mr. Kahal, I have taken into account investor-expected returns, using the Value Line data and returns for the S&P 500 to reach my determination.

Q. Mr. Kahal's market premium of 5.0% to 8.0% indicates a total market return of 7.8% (i.e., 5.0% + 2.8%) to 10.8% (i.e., 8.0% + 2.8%). Please comment.

A. An overall market return at or below 11% is unreasonable at this time, as is shown by the DCF return for the S&P 500 provided below. In this calculation, the 9.12% DCF growth rate for the S&P 500 is taken from the data supplied by Mr. Kahal. The remaining components for the S&P 500 are detailed below. Current market evidence produces total market returns of:

DCF Result for the S&P 500 Composite

D/P		1+.5g		+	g	=	k
2.51%	(	1.0456	)	+	9.12%	=	11.74%

where:	Price (P)	at 31-Dec-2012	=	1426.19
	Dividend (D)	for 4th Qtr. '12	=	8.94
	Dividend (D)	annualized	=	35.76
	Growth (g)	First Call EpS	=	9.12%

These results for the S&P 500 are confirmed by the Value Line forecasts shown below.

		Dividend		Appreciation			Total
Value Line		Yield		Potential			Return
As of December 28, 2012		2.3%	+	11.58%	(4)	=	13.88%

The average of the market returns is 12.81% (13.88% + 11.74% = 25.62% ÷ 2). Moreover, the data presented by Ms. Sears on page 1 of Schedule 10 of I&E Exhibit No. 1 showing a 12.54% expected market return confirms my calculations. The resulting market premium would be 10.01%, using Mr. Kahal's risk-free rate of return of 2.8%, which indicates that the 9.0% indicated by the

[4] The estimated median appreciation potential is forecast to be 55% for 3 to 5 years hence. The annual capital gains yield at the midpoint of the forecast period is 11.58% (i.e., $1.55^{.25}$ - 1).

"high sensitivity" market premiums is also understated.

Q. What are your observations regarding Ms. Sears' application of the CAPM?

A. Ms. Sears's CAPM analysis understates the cost of equity because it uses an understated risk-free rate of return; uses the incorrectly calculated historical market returns that do not reflect investor expected market returns; fails to use leveraged adjusted betas; and fails to make a size adjustment.

Q. How has Ms. Sears understated the risk-free rate of return?

A. The support for her risk-free rate of return is shown on Schedule 9 of I&E Exhibit No. 1. There, she incorrectly gives the same weight to the yield on 10-year Treasury notes for the fourth quarter of 2010 as she does for the entire five year period 2012 through 2016. This approach leads to a seriously understated risk-free rate of return. There are a variety of problems with her approach. First, all of the yields on 10-year Treasury notes for 2010, 2011 and 2012 are past and not useful in the forecast. Second, the rates in this proceeding will not become effective until the third quarter of 2013. Therefore, it is necessary to correct the quarterly and annual data to be considered in the risk-free rate of return and the weights assigned to the forecast data presented by Ms. Sears. I have revised her forecast below, based upon the Blue Chip Financial Forecast dated January 1, 2013.

Year	10-Year Treasury Yield
2013	2.1%
2014	2.6%
2015	3.4%
2016	4.2%
2017	4.7%
Average	3.4%

The correct risk-free rate of return is 3.4%.

Q. What are your observations concerning Ms. Sears' calculation of the historical market return using the S&P Composite Index data?

A. Ms. Sears' analysis substantially misses the mark. First of all, the historical market premiums that she developed are not representative of the future. A 6.02% market return for the S&P 500 using historical data shown on page 2 of Schedule 10 of I&E Exhibit No. 1 cannot possibly be correct given that she determined the DCF return for her gas barometer group to be 8.51%. It is inconceivable that the S&P 500, which by definition has a beta of 1.00, could have a lower expected market return than the barometer group, which has a beta of 0.66. It is further inconceivable that investors would expect the unduly low returns of -0.25% and 2.92% for the 5-year and 10-year periods shown on page 2 of Schedule 10 of I&E Exhibit No. 1 to be representative of the future. Further, with her averaging of averages, she has counted the 5-year and 10-year periods multiple times. It is clear that Ms. Sears has introduced a substantial downward

bias to her conclusion by introducing these unrealistic historical returns in her data. The average of her remaining historical market returns are 9.14% (7.81% + 9.83% + 9.77% = 27.41% ÷ 3), which shows that the 6.02% historical market return presented by Ms. Sears is unrealistic. Further, her historical return analysis is invalid because rests with her use of the geometric mean. The theoretical foundation of the CAPM requires that the arithmetic mean be used because it conforms to the single period specification of the model, provides a representation of all probable outcomes, and has a measurable variance. The geometric mean that Ms. Sears considers consists merely of a rate of return taken from two data points and cannot provide a reasonable representation of the market risk premium in the context of the CAPM. The fallacy of her two-point data input helps explain the unreasonableness of her 5-year and 10-year market returns of -0.25% and 2.92%, respectively. This is because the calculation is totally dependent upon the initial value and the terminal value that she chooses. If these values contain an anomaly, which is the case of the five-year and two-year data, then the results cannot be relied upon. As stated by Ibbotson:

> *Arithmetic Versus Geometric Differences*
> For use as the expected equity risk premium in the CAPM, the arithmetic or simple difference of the arithmetic means of stock market returns and riskless rates is the relevant number. This is because the CAPM is an additive model where the cost of capital is the sum of its parts. Therefore, the CAPM expected equity risk premium must be derived by arithmetic, not geometric, subtraction.

> *Arithmetic Versus Geometric Means*
> The expected equity risk premium should always be calculated using the arithmetic mean. The arithmetic mean is the rate of return which, when compounded over multiple periods, gives the mean of the probability distribution of ending wealth values....This makes the arithmetic mean return appropriate for computing the cost of capital. The discount rate that equates expected (mean) future values with the present value of an investment is that investment's cost of capital. The logic of using the discount rate as the cost of capital is reinforced by noting that investors will discount their (mean) ending wealth values from an investment back to the present using the arithmetic mean, for the reason given above. They will therefore require such an expected (mean) return prospectively (that is, in the present looking toward the future) in order to commit their capital to the investment. (Stocks, Bonds, Bills and Inflation - 1996 Yearbook, pages 153-154

The arithmetic return for the 86-year period used by Ms. Sears was 11.76%, which is more realistic and better fits the forecast market return of 12.54% that she determined.

Q. Does the comparison of the market premium (Rm-Rf) between the historical and forecasts show how unreliable the calculation of the CAPM is presented by Ms. Sears?

A. Yes. Her market premium (Rm-Rf) using forecast data is 10.28% (i.e., 12.54% - 2.26%) and with the historical data it is just 3.76% (i.e., 6.02% - 2.26%). Given the extraordinary low level of Treasury yields at present, investor expectations include a market premium that exceeds substantially the historical calculations. That is to say, with unusually low interest rates, investors expect higher market premiums in recognition of the risk associated with higher inflation

prospectively and with the prospect of higher interest rates in the future. It is for this reason that a 3.76% market premium using historical data presented by Ms. Sears cannot be used in the CAPM, which is an expectational model of investor expected returns.

Q. Mr. Kahal and Ms. Sears also question the need to further adjust the CAPM results for size differences. Please comment.

A. Mr. Kahal rejects the adjustment to the CAPM due to the relatively small market capitalization of the Gas Group. He says that my evidence is limited and apparently does not relate to utilities. He goes on to observe that Columbia is part of NiSource, which is a large cap company according to Value Line. But, my size adjustment was derived for the Gas Group, which serves as a proxy for Columbia, not NiSource. And, I provided four citations to the need for a size adjustment and the quantification for that adjustment was the SBBI Yearbook that utilized market returns that included public utilities. Moreover, the Zepp article referenced below applied specifically to public utilities. In opposing the size adjustment, Ms. Sears cites to an article by Annie Wong that was published in 1993. However, the Wong article employed data going back into the 1960s, or roughly fifty years ago. Enormous changes have occurred in the industry since the 1960s that have fundamentally changed the utility business. The Wong article also noted that betas for the non-regulated companies were larger than the betas of the utilities. This, however, is not a revelation, because history shows that utilities generally have lower betas than many other companies. In

addition, Ms. Wong's beta observation says nothing about the relative risk associated with small size.

The Wong article further concludes that size cannot be explained in terms of beta. Again, this should not be a surprise. Beta is not the tool that should be employed to make that determination. Indeed, beta is a measure of systematic risk and it does not provide the means to identify the return necessary to compensate for the additional risk of small size. In contrast, the famous Fama/French study (see "The Cross-Section of Expected Stock Returns," The Journal of Finance, June 1992) identified size as a separate factor that helps explain returns. Further, an article by Dr. Thomas Zepp presented research on water utilities that confirmed the existence of a small firm effect in the utility industry.[5]

Q. How would the correction of each of the issues that you have discussed affect Ms. Sears' CAPM results?

A. Her CAPM results would increase significantly. An average of the 11.76% historical arithmetic mean return and the 12.54% forecast market return yields a 12.15% (11.76% + 12.54% = 24.30% ÷ 2) market return. Using the Value Line forecasts of a total market return, the market premium would be 11.37% (14.77% - 3.4%), which would fully accommodate the expectational specification of the CAPM. Along with the 3.4% risk-free rate of return that I developed above, the market premium would be 8.75% (12.15% - 3.4%). In addition, the size of the

[5] Zepp, Thomas M. (2002) "Utility stocks and the size effect: revisited". Economics and Finance Quarterly, 43, 578-582.

gas barometer group must be recognized. Making these corrections, the CAPM result would be 10.32% as shown below.

	Rf	+	*ß*	*x (Rm-Rf)*	+	*size*	=	*k*
Gas Barometer Group	3.4%	+	0.66	x (8.75%)	+	1.14%	=	10.32%
Gas Barometer Group	3.4%	+	0.66	x (11.37%)	+	1.14%	=	12.04%

These CAPM results are obtained with the average of historical and forecast total market returns and with the forecast by Value Line. But, this would not represent the end of the corrections necessary to Ms. Sears's CAPM because the leverage adjusted betas should also be employed.

RISK PREMIUM METHOD

Q. Do you believe the Risk Premium method provides significant evidence of the cost of equity?

A. Yes. In my opinion, the Risk Premium results should be given serious consideration. The Risk Premium method is straight-forward, understandable and has intuitive appeal because it is based on a company's own borrowing rate. The utility's borrowing rate provides the foundation for its cost of equity which must be higher than the cost of debt in recognition of the higher risk of equity. So, while Mr. Kahal and Ms. Sears decline to use the Risk Premium approach to measure the Company's cost of equity, it is an approach which provides a direct and complete reflection of a utility's risk and return because it considers additional factors not reflected in the beta measure of systematic risk.

Q. Please respond to Ms. Sears' and Mr. Kahal's comments regarding your Risk Premium approach.

A. Ms. Sears' assertion that the Risk Premium method does not measure the current cost of equity as directly as the DCF is without foundation for the very reason that components of each model carry varying levels of precision in their measurement. For example, the yield on A-rated public utility bonds used in the RP model, and the dividend yields used in the DCF can be measured with a fairly high degree of precision. But the equity risk premium used in the RP model, and the DCF growth rate must all be inferred because they are not directly observable. This reality shows that no one method is superior to another because they all require use of informed judgment to obtain a meaningful result.

Mr. Kahal complains about my use of median values in calculating the equity risk premium. But medians are a widely accepted measure of central tendency and are used frequently in financial analysis. For example, Value Line reports data using medians and I/B/E/S does too. Mr. Kahal also notes that the historical time frame that I used for measuring the equity risk premium ended in 2007. Yet, he relied upon equity risk premiums that ended in 2003 as revealed by the Brealey, Myers and Allen citations provided by Mr. Kahal. If data from 2003 is relevant for Mr. Kahal, then data through 2007 must also be okay. As shown on pages 38 and 39 of Statement No. 10, the 11.01% (4.75% yield on A-rated public utility bonds + 5.50% equity risk premium + 0.76% credit quality

difference) represents the Risk Premium return that I determined for CPA in my direct testimony, which is reasonable.

COMPARABLE EARNINGS

Q. Ms. Sears and Mr. Kahal disagree with your use of the Comparable Earnings approach. Please comment.

A. Ms. Sears claims that my Comparable Earnings analysis should be disregarded because it involves the inclusion of non-regulated companies that have dissimilar risk and historical Commission treatment. However, she never explains why or how these items diminish the value of the Comparable Earnings approach.

The underlying premise of the Comparable Earnings method is that regulation should emulate results obtained by firms operating in competitive markets and that a utility must be given an opportunity cost of capital equal to that which could be earned if one invested in firms of comparable risk. For non-regulated firms, the cost of capital concept is used to determine whether the expected marginal returns on new projects will be greater than the cost of capital, i.e., the cost of capital provides the hurdle rate at which new projects can be justified, and therefore undertaken. Because the Comparable Earnings method is derived from a firm's overall performance (i.e., its average return), the approach blends returns on a variety of projects that have produced returns above and below the cost of capital during the measurement period. Further, given the 10-year time frame (i.e., five years historical and five years projected)

considered by my study, it is unlikely that the earned returns of non-regulated firms would diverge significantly from their cost of capital. I have used this approach in connection with the other market models (i.e., DCF, Risk Premium, and CAPM) and the combined results of all methods fulfill established standards of a fair rate of return, i.e. namely, comparability and capital attraction.

The Comparable Earnings approach satisfies the comparability standard established in the Hope case. In addition, the financial community has expressed the view[6] that the regulatory process must consider the returns that are being achieved in the non-regulated sector to ensure that regulated companies can compete effectively.

Q. Mr. Kahal claims that your Comparable Earnings approach is not a cost of equity method. Please comment.

A. As a preliminary matter, Comparable Earnings was the original approach used to determine the rate of return in public utility rate cases and has been around for about 100 years. It predates the use in rate proceedings of the DCF method by at least 50 years. The Comparable Earnings approach was established in the landmark Bluefield & Hope decisions, which set forth the two principal standards of a fair return, namely, comparability and capital attraction. In the Hope decision, the United States Supreme Court defined these requirements: "... the return to the equity owner should be commensurate with returns on investments in other enterprises having corresponding risks. That return,

[6] "Natural Gas: The Case for ROE Reform," John E. Olson First Vice President, Merrill Lynch & Co., October 11, 1994.

moreover, should be sufficient to assure confidence in the financial integrity of the enterprise, so as to maintain its credit and attract capital." Since comparable returns provide a benchmark for measuring a fair return for a public utility, returns on non-regulated companies with comparable risk traits to a public utility meet the standard for a fair return. As I explained in my direct testimony, returns on non-regulated companies of similar risk to public utilities are relevant here because they are not the product of regulatory decisions (i.e., they are determined by competitive market forces).

REGULATORY SUPPORT AND CONCLUSION

Q. Would the rates of return on common equity proposed by the opposing parties have a detrimental impact on how the investment community views the financial condition of CPA and the regulatory support it receives from the Commission?

A. Yes. Technical disputes about methodology and data aside, the cost of equity proposed by Mr. Kahal and Ms. Sears are simply not representative of the returns investors can earn on other investments of comparable risk, including investments in other utilities similar to the Gas Group. In this regard, it is worthwhile to consult other recognized databases to see whether this return is comparable to those returns. Two such databases exist. First, the database of rate case decisions is available from Public Utility Reports ("PUR"). Second, Regulatory Research Association ("RRA"), a service provided by SNL Financial, contains these data. According to both of these databases, the average

regulatory return for 2011 and 2012 is 10.15%. It is also useful to analyze the authorized returns tabulated by RRA according to the rankings assigned to each commission. For this purpose, the authorized returns for electric and gas utilities have been sorted as shown below.

Regulatory Authorized Equity Returns
Years 2011 and 2012

Commission Profiles	Number of Cases	Average Equity Return
Above Average	28	10.76
Average 1	23	10.34
Average 2	42	10.03
Average 3	27	9.68
Below Average	26	9.78
Total	146	10.15

As can be seen above, the higher ranked commissions generally grant higher returns in rate case decisions for the electric and gas utilities. In the case where higher returns are awarded in rate cases, the credit rating agencies and investors view regulatory commissions as providing more support for their utilities. This result is beneficial to both the utilities and their customers, because utilities that have more supportive regulation have better access to capital at lower costs. The rates of return on common equity proposed by Mr. Kahal, and Ms. Sears in particular are woefully inadequate to provide the CPA with the opportunity to earn their cost of capital as investors currently perceive and are likely to perceive for the fully forecast test year. I should note that the recent Commission order in PPL Electric Utilities that provided a 10.4% equity return represents a step in the

right direction.

Q. Are there objective indications of the level of returns expected by investors for the companies that comprise the Gas Group?

A. Yes. According to the Value Line reports dated December 7, 2012, the current and forecasted average returns for the Gas Group are:

2012		10.0%
2013		10.2%
2015-17		10.8%

The returns shown above are those that investors expect for the utilities that comprise the Gas Group. It should be noted that Columbia is more risky than the Gas Group thereby requiring a higher return on equity, which exceed substantially the cost of equity proposal by Mr. Kahal and Ms. Sears, in particular.

Q. Please summarize your rebuttal testimony.

A. It is my opinion that the equity allowances proposed by Mr. Kahal and Ms. Sears significantly understate the Company's cost of common equity.

Q. Does this conclude your rebuttal testimony?

A. Yes.

Exhibit No. 400-R

COLUMBIA GAS OF PENNSYLVANIA, INC.

Schedules to Accompany

The Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Capital

Columbia Gas of Pennsylvania, Inc.
Summary Cost of Capital

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	44.11%	5.81%	2.56%
Short Term Debt	3.57%	1.85%	0.07%
Total Debt	47.68%		2.63%
Common Equity	52.32%	11.25%	5.89%
Total	100.00%		8.52%

Indicated levels of fixed charge coverage assuming that the Company could actually achieve its overall cost of capital:

Pre-tax coverage of interest expense based upon a 41.4935% income tax rate (12.70% ÷ 2.63%)	4.83 x
Post-tax coverage of interest expense (8.52% ÷ 2.63%)	3.24 x

Columbia Gas of Pennsylvania, Inc.
Long-term Debt Outstanding
Estimated at June 30, 2014

Date of Issuance	Coupon Rate	Amount Outstanding	Annualized Debt Service	Embedded Cost of Debt
November 28, 2005	5.41%	47,350,000	2,561,635	
November 28, 2005	5.45%	18,525,000	1,009,613	
November 28, 2005	5.92%	54,515,000	3,227,288	
November 1, 2006	6.015%	20,000,000	1,203,000	
December 14, 2007	6.865%	58,000,000	3,981,700	
December 16, 2010	6.020%	28,000,000	1,685,600	
March 28, 2012	5.355%	30,000,000	1,606,500	
March 28, 2012	5.890%	35,000,000	2,061,500	
November 28, 2012	5.26%	64,825,000	3,409,795	
May 2013	5.70%	33,175,000	1,890,975	
December 18, 2013	5.74%	22,000,000	1,262,800	
June 2014	5.77%	18,000,000	1,038,600	
Total Long-Term Debt		429,390,000	24,939,006	5.81%
Short Term Debt (Twelve month average)	1.85%	34,785,000	643,523	
Total Debt		$ 464,175,000	$ 25,582,528	5.51%

Source of information: Company provided data

NiSource
Corporate Treasury Department

To: Files
From: Treasury Operations
Date: January 14, 2013
Re: CPA Intercompany Notes Forecasted Issuance Cost

Objective

Provided below are forecasted rates for intercompany notes estimated to be issued at end of May 2013, December 2013, and June 2014, as well as actual rates for the Notes that were recently issued in November 2012. These rates are comprised of forward rates for U.S. Treasuries and NiSource's BBB- credit spread.

Results

Issuance	US Treasury Rate (1)	NiSource BBB- Spread (2)	All-in Coupon Rate
28-Nov-12	2.7900%	2.4700%	5.2600%
31-May-13	3.0614%	2.6432%	5.7046%
31-Dec-13	3.1473%	2.5902%	5.7375%
30-Jun-14	3.2198%	2.5540%	5.7738%

1) U.S. Treasury forecasted rates were obtained from Bloomberg's forward curve matrix on 1/14/2013 for 30-year bonds. The U.S. Treasury rate for the November 2012 issuance was obtained from the Federal Reserve Statistical Release dated November 29, 2012, showing November 28, 2012 Treasury Yields.

2) CPA/NiSource's forecasted credit spread was obtained from Reuter's Corporate Bond Utility Spread Tables for a BBB- credit rating as of 1/7/2013 reflecting a spread of 267 basis points for a 30 year note. An assumption was made for 2013 and 2014 debt issuances that this credit spread would change inversely to the change in the U.S. Treasury rate by approximately one-half. The credit spread for the November 28, 2012 issuance was obtained from Reuters Corporate Bond Spread for Utilities dated November 28, 2012.

Gas Group

Internal Growth ("b x r") 3 to 5 Year Projections

Company	Dividends Per Share	Earnings Per Share	Book Value Per Share	Prior Y/E Book Value	Average Book Value	ROE	Payout Ratio	Retention Rate	Internal Growth Rate	Return on Com Equity	Earnings Retention
AGL Resources, Inc.	$1.96	$3.80	$33.30	$31.46	$32.38	11.74%	51.58%	48.42%	5.68%	5.5%	6.5%
Atmos Energy Corp.	$1.48	$2.70	$34.65	$33.43	$34.04	7.93%	54.81%	45.19%	3.58%	8.0%	3.5%
Laclede Group, Inc.	$1.84	$3.30	$33.00	$31.54	$32.27	10.23%	55.76%	44.24%	4.52%	10.0%	4.5%
New Jersey Resources Corp	$1.68	$3.40	$24.20	$22.48	$23.34	14.57%	49.41%	50.59%	7.37%	14.0%	7.5%
Northwest Natural Gas	$1.96	$3.15	$27.75	$26.56	$27.16	11.60%	62.22%	37.78%	4.38%	11.5%	4.0%
Piedmont Natural Gas Co.	$1.35	$1.85	$14.60	$14.10	$14.35	12.89%	72.97%	27.03%	3.48%	12.5%	3.5%
South Jersey Industries, Inc	$2.30	$4.50	$27.80	$25.60	$26.70	16.85%	51.11%	48.89%	8.24%	16.0%	7.5%
Southwest Gas Corporation	$1.60	$3.75	$36.00	$33.85	$34.93	10.74%	42.67%	57.33%	6.16%	10.5%	6.0%
WGL Holdings, Inc.	$1.75	$2.75	$28.65	$27.65	$28.15	9.77%	63.64%	36.36%	3.55%	9.5%	3.5%
Average						**11.81%**	**56.02%**	**43.98%**	**5.22%**	**10.8%**	**5.2%**

External Growth ("s x v") 3 to 5 Year Projections

	2011 Book Value per Share	Stock Price	1-(B/P)	Common Shares Outst'g 2011	Common Shares Outst'g 2015-17	Com Shs. Growth x M/B	External Growth Rate	"b times r" plus "s times v"
AGL Resources, Inc.	$28.54	$38.41	0.2570	117.00	117.00	0.00%	0.00%	5.68%
Atmos Energy Corp.	$24.98	$34.78	0.2818	90.30	103.00	3.71%	1.05%	4.63%
Laclede Group, Inc.	$25.56	$39.89	0.3592	22.43	23.50	1.46%	0.52%	5.05%
New Jersey Resources Corp	$18.73	$40.33	0.5356	41.45	40.00	-1.53%	neg.	7.37%
Northwest Natural Gas	$26.70	$43.28	0.3831	26.76	28.00	1.48%	0.57%	4.95%
Piedmont Natural Gas Co.	$13.79	$30.34	0.5455	72.32	68.00	-2.69%	neg.	3.48%
South Jersey Industries, Inc	$20.66	$48.96	0.5780	30.21	36.00	8.46%	4.89%	13.13%
Southwest Gas Corporation	$26.66	$41.30	0.3545	45.96	50.00	2.63%	0.93%	7.09%
WGL Holdings, Inc.	$23.49	$37.81	0.3787	51.20	52.00	0.50%	0.19%	3.74%
Average							**1.16%**	**6.12%**

Source: The Value Line Investment Survey, December 7, 2012

COLUMBIA STATEMENT NO. 111-R

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

PANPILAS W. FISCHER

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. Panpilas W. Fischer, 200 Civic Center Drive, Columbus, Ohio 43215

Q. By whom are you employed?

A. I am employed by NiSource Corporate Services Company.

Q. Are you the same Panpilas W. Fischer who submitted Direct Testimony in this Proceeding?

A. Yes.

Q. What is the purpose of your Rebuttal Testimony in this proceeding?

A. Subsequent to the filing of my prepared Direct Testimony, Thomas S. Catlin filed direct testimony of behalf of the Pennsylvania Office of Consumer Advocate related to the calculation of income taxes. This testimony will respond to the recommendations of Mr. Catlin. In addition, my Rebuttal Testimony will update the pro forma test year tax schedules that were originally filed on June 6, 2012 for: 1) the impact of federal tax laws signed into law on January 2, 2013 (the American Taxpayer Relief Act of 2012); 2) changes to Accumulated Deferred Income Tax ("ADIT") and tax expense as a result of a subsequent IRS audits and Revenue Procedure; 3) changes to tax expense as a result of other updates to Columbia's claims for expenses and rate base presented by other Columbia witnesses; 4) the effect of additional future test year plant additions.

Q. On page 31 of Mr. Catlin's Direct Testimony a correction has been proposed to flow through the benefit of the operating loss deduction in calculating current state income taxes. Is this correction appropriate?

A. Yes, I concur with Mr. Catlin's adjustment in eliminating the deferred state

income tax offset for the state net operating loss deduction that was inadvertently included in my calculation on Exhibit No. 107, page 17. This results in a net decrease to income tax expense because the state net operating loss is a benefit.

Q. What updates impacting the pro forma test year tax schedules have occurred since they were originally filed?

A. On January 2, 2013 the American Taxpayer Relief Act of 2012 ("2012 Tax Act") was signed into law. As relevant to Columbia's claim in this case, the 2012 Tax Act extended 50% bonus depreciation for federal income tax purposes for 2013. The majority of assets placed in service in the test period will qualify for 50% bonus depreciation. The original filing included 2013 assets at a 3.75% tax depreciation rate, which is the rate allowable under the Modified Accelerated Cost Recovery System for 20 year gas distribution property. The change in law creates additional federal tax depreciation deductions in the Fully Forecasted Rate Year ("FFRY") which results in an increase to deferred income taxes of $3,366,714. This amount is net of the deferred tax asset on the Federal net operating loss ("NOL") and the pro forma normalization adjustment. This change in deferred taxes is shown on Exhibit PWF-1R, which is a revision of Exhibit 107, page 5.

Q. Why is there a change in the ADIT for the Federal net operating loss?

A. As I explained in Direct Testimony, because of 50% and 100% bonus depreciation and the repairs allowance deduction, Columbia has incurred tax losses in recent years, and thus has not been able to claim the full benefit of prior period depreciation deductions. These unutilized deductions are an offset to the ADIT

balance. Columbia projected to amortize most of this deferred NOL asset over the FTY and FFRY years, thereby restoring most of the ADIT balance. However, the allowance of additional federal bonus depreciation deductions will reduce Columbia's federal taxable income, thereby reducing the amortization of the deferred NOL asset. Since many companies in the NiSource affiliated group are capital intensive and will also generate additional federal tax depreciation deductions from bonus depreciation, the NiSource affiliated group will not be able to fully utilize the net operating loss until the end of 2015.

Q. Does the allowance of a 50% bonus depreciation deduction for Federal Income Tax purposes affect Columbia's claim for state income tax expense?

A. No. Previously, when bonus depreciation was 50%, the Commonwealth of Pennsylvania has disallowed bonus depreciation so the state depreciation deduction is computed effectively as if the bonus did not exist.

Q. Why is there a change in the ADIT on plant for the pro forma normalization adjustment?

A. As explained in my Direct Testimony, the IRS Regulations require that deferred taxes be reflected on a pro rata basis whenever there are estimated changes in the deferred taxes that occur in a test period after the effective date of a rate order. Not doing so would violate the principles of the Normalization requirements under the Internal Revenue Code. Since some of the deferred taxes on the 50% bonus depreciation deduction occur in the FFRY, the normalization adjustment has been recalculated to reflect this change.

Q. What other updates are you including in your Rebuttal Testimony?

A. As a result of the recently completed IRS audit of tax year 2008, the Company is receiving a favorable settlement on the remaining repairs refund claimed in the amount of $12,791,578. Prior to this IRS settlement, parties were aware that this amount was held back from the original claim, and were advised that the claim was unaudited and the amount could change. The original amount claimed was $49,695,938. Of this amount the Company had already received an amount of $37,487,634 in 2009 which is being refunded to customers through amortization as stated in my prepared Direct Testimony. The original difference of $12,208,301 ($49,695,938 - $37,487,634) increased to $12,791,578 as a result of other pro-rata 2008 activity. At the settlement of Columbia's 2010 rate case, it was agreed that if the amount claimed increased or decreased the change would be reflected in ADIT. We are now at a point where the IRS is in the process of issuing, and the Company is aware of, an upcoming Revenue Procedure on the repairs change in method of accounting for gas distribution. The Revenue Procedure is the U.S. Treasury Department's official interpretation of tax legislation and provides industry specific guidance on the details of calculating the repairs deduction. Under the Revenue Procedure the amount that will be allowed is defined. The Revenue Procedure allows taxpayers to adopt a permissible method of calculating the repairs tax deduction and receive an automatic change in method of accounting which will not require prior consent from the IRS and the taxpayer receives full audit protection on the original change in method of accounting for the repairs tax deduction. In addition, the entire adjustment (whether positive or negative) must be included in computing

taxable income in the year of change (the Company's 2013 federal tax return). Based on the Revenue Procedure, the Company has recalculated the change in the original repairs deduction and is now aware that it will owe the IRS an estimated $7,427,455 and will be recording a liability to the IRS. As for the original claim, the Company expects to receive cash for the $12,791,578 refund in July 2013. For Exhibit purposes, the Company recorded an increase to ADIT for the refund amount so customers will receive the benefit of the refund through a reduction in rate base. There is no offsetting increase to rate base due to a change to the Federal ADIT NOL asset as a result of the refund because corporations are allowed to carryback NOLs two years. The taxable loss generated by the refund claim was carried back to 2007. In 2007, the NiSource affiliated group paid sufficient tax to the IRS to absorb the refund claim. At the same time, we are reflecting the change in the Revenue Procedure which is going to disallow some of what we previously claimed as an allowed deduction, which has the reverse effect. The Revenue Procedure results in a decrease to ADIT of $7,427,455 before taking into account the Federal NOL ADIT asset. In this situation, there will be a partial offset to this ADIT decrease by the reduction to the Federal NOL ADIT asset as additional net operating loss will be utilized from the increased taxable income and there is no NOL carryback available to tax years in the FFRY due to the two year carryback limitation. To the extent we are increasing income we are utilizing some of the NOL ADIT asset. To the extent we are decreasing income, we utilize less of the NOL ADIT asset. The net decrease to deferred taxes for the $7,427,455 tax expected to be owed is $3,183,195. Since the additional income is

treated as flow through for state income tax purposes, there will be an increase to state tax expense of $1,184,973.

Q. Are there any other updates you want to include in your Rebuttal Testimony?

A. Yes. Since the filing of my prepared Direct Testimony, the audit of the 2009 federal tax return has been completed and the Company will be allowed a refund of $4,553,314 for claimed 263A mixed service cost deductions. The refund is expected to be received July 2013 and the Company has accordingly increased deferred income taxes as a result of the expected refund passing the full benefit to customers through the reduction in rate base. Similar to the 2008 repairs refund discussed above, there is no impact to the federal net operating loss because the 2009 NOL is within the allowable carryback period of 2 years and has been carried back to 2007. The change in deferred taxes for the amount of the expected refund is shown on Exhibit PWF-1R

Q. Are there any other adjustments to the Company's rate base?

A. As a result of additional assets being placed in service during the future test year, as described in the Rebuttal Testimony of Witness Cote, the Company is entitled to more tax depreciation during the FFRY. All of this $3.2 million in additional plant will be 50% deductible, with a portion treated as repairs and mixed service costs for tax purposes and the remainder capitalized and depreciated. With these tax deductions, the Company is decreasing income and utilizing less NOL, therefore the ADIT increase due to the additional assets being placed in service is partially offset by an increase to the ADIT NOL asset.

Q. Are there other adjustments to the Company's claimed tax expense?

A. Yes. In rebuttal testimony of Columbia witness Gore (Columbia Statement No. 104-R), certain adjustments have been made to the Company's claim. These adjustments revise the Company's current and deferred tax expense.

Q. Have you prepared revised exhibits that detail all of the changes to income tax expense and ADIT?

A. Yes. I have prepared Exhibit PWF-2R to account for the changes discussed above, except for the changes for the additional assets to be placed in service. The ADIT and tax expense impacts of the additional assets placed in service have been included in witness Gore's Exhibit JTG-R2 Schedule 5.

Q. Does this conclude your rebuttal testimony?

A. Yes it does.

COLUMBIA GAS OF PENNSYLVANIA, INC.

CALCULATION OF DEFERRED TAX BALANCES

Sub Account		Book Balances 05/31/12	Pro-Forma Adjustments Existing Rates	Pro-Forma Balance 05/31/12	Deferred Tax Activity 6/1/12-5/31/13	Pro-Forma Adjustments Proposed Rates	Pro-Forma Tax Balance 05/31/13	Pro-Forma Tax Balance 06/30/13	Pro-Forma Tax Balance 07/31/13	Pro-Forma Tax Balance 08/31/13	Pro-Forma Tax Balance 09/30/13	Pro-Forma Tax Balance 10/31/13
	Account 190 - Deferred Income Taxes											
1938	LIFO Inventory Adj - Fed	(12,172,526)	-	(12,172,526)	5,149,085	-	(7,023,441)	(6,594,351)	(6,201,018)	(5,807,685)	(5,414,352)	(5,021,019)
3938	LIFO Inventory Adj - St	(3,859,990)	-	(3,859,990)	1,632,814	-	(2,227,176)	(2,091,108)	(1,966,379)	(1,841,650)	(1,716,921)	(1,592,192)
1947	Capitalized Inventory - Fed	(1)	-	(1)	-	-	(1)	(1)	(1)	(1)	(1)	(1)
3947	Capitalized Inventory - St	(2)	-	(2)	-	-	(2)	(2)	(2)	(2)	(2)	(2)
2851	Customer Advances - Fed	1,591,413	-	1,591,413	157,518	-	1,748,931	1,762,057	1,774,090	1,786,123	1,798,156	1,810,189
4851	Customer Advances - St	504,608	-	504,608	49,950	-	554,558	558,721	562,537	566,353	570,169	573,985
1960/2960	Tax Method Change: Repair - Fed	13,104,108	(13,104,108)	-	-	-	-	-	-	-	-	-
3960/4960	Tax Method Change: Repair - St	4,155,425	(4,155,425)	-	-	-	-	-	-	-	-	-
4957	Pennsylvania Net Operating Loss- St	20,436,214	(20,436,214)	-	-	-	-	-	-	-	-	-
2969	Federal Net Operating Loss	31,652,617	-	31,652,617	(15,544,898)	-	16,107,719	14,812,311	14,077,100	13,341,890	12,606,679	11,871,469
	All Other Deferred 190 Income Taxes	13,519,664	(13,519,664)	-	-	-	-	-	-	-	-	-
	Total Account 190	68,931,530	(51,215,411)	17,716,119	(8,555,531)	-	9,160,588	8,447,827	8,246,327	8,045,028	7,843,728	7,642,429
	Account 255 - Deferred Investment Tax Credits											
	Investment Tax Credits (1962-1969)	-		-	-		-	-	-	-	-	-
	Job Development Tax Credits (1971-1988)	(4,113,243)	4,113,243	-	-	-	-	-	-	-	-	-
	Total Account 255	(4,113,243)	4,113,243	-	-	-	-	-	-	-	-	-
	Account 282 - Deferred Income Taxes-Depreciation											
2205	Excess Accelerated Tax Depreciation - Fed	(168,462,040)	3,347,532	(165,114,508)	(34,091,455) A	(17,938,126) B	(217,144,089)	(219,923,549)	(221,119,484)	(222,158,832)	(223,041,653)	(223,772,977)
2908	SFAS 109 Offset - Fed	(125,856,759)	125,856,759	-	-	-	-	-	-	-	-	-
4908	SFAS 109 Offset - St	(88,565,596)	88,565,596	-	-	-	-	-	-	-	-	-
5213	Non-Utility Other - Fed	(104)	104	-	-	-	-	-	-	-	-	-
6900	Non-Utility Book Gain on Sale Property - Fed	(95,847)	95,847	-	-	-	-	-	-	-	-	-
	Total Account 282	(382,980,346)	217,865,838	(165,114,508)	(34,091,455)	(17,938,126)	(217,144,089)	(219,923,549)	(221,119,464)	(222,158,832)	(223,041,653)	(223,772,977)
	Account 283-Deferred Income Taxes-Other											
2951	Legal Liability-Lease on G.O. Bldg. - Fed	(122,776)	-	(122,776)	52,519	-	(70,257)	(65,880)	(61,868)	(57,856)	(53,844)	(49,832)
4951	Legal Liability-Lease on G O. Bldg. - St	(39,024)	-	(39,024)	16,654	-	(22,370)	(20,962)	(19,710)	(18,438)	(17,166)	(15,894)
2957	Pennsylvania Net Operating Loss- Federal Offset	(7,152,661)	7,152,661	-	-	-	-	-	-	-	-	-
	All Other Deferred 283 Income Taxes	(3,134,991)	3,134,991	-	-	-	-	-	-	-	-	-
	Total Account 283	(10,449,452)	10,287,652	(161,800)	69,173	-	(92,627)	(86,862)	(81,578)	(76,294)	(71,010)	(65,726)
	Total Accumulated Deferred Taxes	(328,611,511)	181,051,322	(147,560,189)	(42,577,812)	(17,938,126)	(208,076,127)	(211,562,783)	(212,954,714)	(214,190,097)	(215,268,934)	(216,196,273)

A

Original	(28,099,410)
Bonus Depreciation	(7,118,800)
Book Depr Change	1,126,755
	(34,091,455)

B

Original	-
Repairs Refund 2008	(12,791,578)
263A Refund 2009	(4,553,314)
Bonus Depreciation 1	(593,234)
	(17,938,126)

COLUMBIA GAS OF PENNSYLVANIA, INC.

CALCULATION OF DEFERRED TAX BALANCES

Sub Account		Pro-Forma Tax Balance 11/30/13	Pro-Forma Tax Balance 12/31/13	Pro-Forma Tax Balance 01/31/14	Pro-Forma Tax Balance 02/28/14	Pro-Forma Tax Balance 03/31/14	Pro-Forma Tax Balance 04/30/14	Pro-Forma Tax Balance 05/31/14	Pro-Forma Tax Balance 06/30/14	Deferred Tax Activity 7/1/13-6/30/14	Pro-Forma Adjustments Proposed Rates	Pro-Forma Tax Balance 06/30/14
	Account 190 - Deferred Income Taxes											
1938	LIFO Inventory Adj - Fed	(4,627,686)	(4,234,353)	(3,841,020)	(3,447,687)	(3,054,354)	(2,661,021)	(2,267,688)	(1,874,355)	5,149,085	-	(1,874,355)
3938	LIFO Inventory Adj - St	(1,467,463)	(1,342,734)	(1,218,005)	(1,093,276)	(968,547)	(843,818)	(719,089)	(594,361)	1,632,814	-	(594,361)
1947	Capitalized Inventory - Fed	(1)	(1)	(1)	(1)	(1)	(1)	(1)	(1)	-	-	(1)
3947	Capitalized Inventory - St	(2)	(2)	(2)	(2)	(2)	(2)	(2)	(2)	-	-	(2)
2851	Customer Advances - Fed	1,822,222	1,834,255	1,846,288	1,858,321	1,870,354	1,882,387	1,894,420	1,906,448	157,518	-	1,906,448
4851	Customer Advances - St	577,801	581,617	585,433	589,249	593,065	596,881	600,697	604,508	49,950	-	604,508
1960/2960	Tax Method Change: Repair - Fed	-	-	-	-	-	-	-	-	-	-	-
3960/4960	Tax Method Change: Repair - St	-	-	-	-	-	-	-	-	-	-	-
4957	Pennsylvania Net Operating Loss- St	-	-	-	-	-	-	-	-	-	-	-
2969	Federal Net Operating Loss	11,136,258	10,401,048	9,665,837	8,930,627	8,195,416	7,460,206	6,724,995	5,989,788	(9,673,534) C	-	6,434,185
	All Other Deferred 190 Income Taxes	-	-	-	-	-	-	-	-	-	-	-
	Total Account 190	7,441,129	7,239,830	7,038,530	6,837,231	6,635,931	6,434,632	6,233,332	6,032,025	(2,684,167)	-	6,476,421
	Account 255 - Deferred Investment Tax Credits											
	Investment Tax Credits (1962-1969)	-	-	-	-	-	-	-	-	-		-
	Job Development Tax Credits (1971-1988)	-	-	-	-	-	-	-	-	-	-	-
	Total Account 255	-	-	-	-	-	-	-	-	-	-	-
	Account 282 - Deferred Income Taxes-Depreciation											
2205	Excess Accelerated Tax Depreciation - Fed	(224,347,754)	(224,771,034)	(225,037,768)	(225,147,955)	(225,116,744)	(224,928,987)	(224,569,733)	(224,098,976)	(22,592,950) D	15,638,064 E	(224,098,975)
2908	SFAS 109 Offset - Fed	-	-	-	-	-	-	-	-	-	-	-
4908	SFAS 109 Offset - St	-	-	-	-	-	-	-	-	-	-	-
5213	Non-Utility Other - Fed	-	-	-	-	-	-	-	-	-	-	-
6900	Non-Utility Book Gain on Sale Property - Fed	-	-	-	-	-	-	-	-	-	-	-
	Total Account 282	(224,347,754)	(224,771,034)	(225,037,768)	(225,147,955)	(225,116,744)	(224,928,987)	(224,569,733)	(224,098,976)	(22,592,950)	15,638,064	(224,098,975)
	Account 283-Deferred Income Taxes-Other											
2951	Legal Liability-Lease on G.O. Bldg. - Fed	(45,820)	(41,808)	(37,796)	(33,784)	(29,772)	(25,760)	(21,748)	(17,738)	52,519	-	(17,738)
4951	Legal Liability-Lease on G.O. Bldg. - St	(14,622)	(13,350)	(12,078)	(10,806)	(9,534)	(8,262)	(6,990)	(5,716)	16,654	-	(5,716)
2957	Pennsylvania Net Operating Loss- Federal Offset	-	-	-	-	-	-	-	-	-	-	-
	All Other Deferred 283 Income Taxes	-	-	-	-	-	-	-	-	-	-	-
	Total Account 283	(60,442)	(55,158)	(49,874)	(44,590)	(39,306)	(34,022)	(28,738)	(23,454)	69,173	-	(23,453)
	Total Accumulated Deferred Taxes	(216,967,066)	(217,586,361)	(218,049,111)	(218,355,313)	(218,520,118)	(218,528,376)	(218,385,138)	(218,090,405)	(25,207,943)	15,638,064	(217,646,007)

Original	(12,798,529)
Bonus Depreciation	7,369,255
Revenue Procedure	(4,244,260)
	(9,673,534) C

Original	(22,118,559)
Bonus Depreciation	(7,901,846)
Revenue Procedure	7,427,455
	(22,592,950) D

Original	11,993,511
Bonus Depreciation	4,284,677
Revenue Procedure	(640,125)
	15,638,063 E

COLUMBIA GAS OF PENNSYLVANIA, INC.

RECONCILIATION OF TAXABLE NET INCOME PER BOOKS
AND TAXABLE NET INCOME PRO FORMA TEST YEAR BASE RATES
FTY = FUTURE TEST YEAR TME 5/31/13, FFRY = FULLY FORECASTED RATE YEAR PERIOD ENDED JUNE 30, 2014

Line No.	Description	Pro Forma At Historic Test Year Base Rates	FTY Adjustments @ Present Rates	See note	FTY Test Year	FFRY Adjustments @ Present Rates	FFRY Test Year	Adjustments	FFRY @ Proposed Rates
		(1)	(2)		(3=1+2)	(4)	(5=3+4)	(6)	(7=5+6)
		$	$		$	$	$	$	$
1	Operating Revenues	375,153,332	3,192,941		378,346,273	1,322,400	379,668,673	73,284,617	452,953,290
2	Net Gas Purchased for Resale	(148,223,679)	(1,188,693)		(149,412,372)	(786,255)	(150,198,627)	0	(150,198,627)
3	Operation and Maintenance Expense	(125,484,092)	(4,283,349)		(129,767,441)	(6,139,411)	(135,906,852)	(1,068,489)	(136,975,341)
4	Depreciation & Amortization Expense	(32,744,846)	(4,264,534)		(37,009,382)	(4,390,230)	(41,399,612)	(1)	(41,399,613)
5	Taxes Other Than Income Taxes	(4,054,326)	233,149		(3,821,177)	177,331	(3,643,846)	0	(3,643,846)
6	Net Operating Income Before Income Taxes	64,646,387	(6,310,486)		58,335,901	(9,816,165)	48,519,736	72,216,127	120,735,863
7	Investment in Subsidiary Income	0	0		0	0	0	0	0
8	Non-Utility Income - Net	0	0		0	0	0	0	0
9	Interest Charges	0	0		0	0	0	0	0
10	Net Income Before Income Taxes	64,646,387	(6,310,486)		58,335,901	(9,816,165)	48,519,736	72,216,127	120,735,863
11	Less: Investment in Subsidiary Income	0	0		0	0	0	0	0
12	Net Income Before Income Taxes	64,646,387	(6,310,486)		58,335,901	(9,816,165)	48,519,736	72,216,127	120,735,863
13	Statutory Adjustments (Page 14, Line 33)	(138,324,543)	43,500,750		(94,823,793)	29,078,453	(65,745,340)	0	(65,745,340)
14	Deductible State Income Tax	5,418,894	(5,604,705)		(185,811)	303,109	117,298	(6,034,732)	(5,917,434)
15	Taxable Income	(68,259,262)	31,585,559		(36,673,703)	19,565,397	(17,108,306)	66,181,395	49,073,089
16	Federal Income Tax	(23,890,742)	11,054,946		(12,835,796)	6,847,889	(5,987,907)	23,163,488	17,175,581
17	Federal Net Operating Loss Carryforward	0	0		0	0	0	0	0
18	Deferred Federal Income Tax - Net	42,275,950	(14,138,412)		28,137,538	(11,301,903)	16,835,635	0	16,835,635
19	Tax Refund Amortization	(10,652,274)	(4,262,166)		(14,914,440)	10,825,020	(4,089,420)	0	(4,089,420)
20	Flow Back of Excess Deferred Income Taxes	(309,311)	(319,057)		(628,368)	0	(628,368)	0	(628,368)
21	Effect of CNIT Deferred Tax	(1,707,752)	1,159,578		(548,174)	0	(548,174)	0	(548,174)
22	Total Federal Income Tax	5,715,871	(6,505,111)		(789,240)	6,371,006	5,581,766	23,163,488	28,745,254
23	Amortization of Investment Tax Credits	(360,239)	0		(360,239)	0	(360,239)	0	(360,239)
24	Net Federal Income Tax Expense	5,355,632	(6,505,111)		(1,149,479)	6,371,006	5,221,527	23,163,488	28,385,015
25	State Income Tax Expense	(539,603)	2,291,625		1,752,022	(303,110)	1,448,912	6,034,733	7,483,645
26	Total Income Tax Expense	4,816,029	(4,213,486)		602,543	6,067,896	6,670,439	29,198,221	35,868,660
27	**NET INCOME**	59,830,358	(2,097,000)		57,733,358	(15,884,061)	41,849,297	43,017,906	84,867,203

Note: See Exhibit No. 7, Pages 15-16 for an explanation of adjustments.

COLUMBIA GAS OF PENNSYLVANIA, INC.

RECONCILIATION OF TAXABLE NET INCOME PER BOOKS
AND TAXABLE NET INCOME PRO FORMA TEST YEAR BASE RATES
FTY = FUTURE TEST YEAR TME 5/31/13, FFRY = FULLY FORECASTED RATE YEAR PERIOD ENDED JUNE 30, 2014

( ) Denotes Credit

Line No.	Description		1/ Pro Forma At FTY Test Year Base Rates $	1/ Pro Forma At FFRY Test Year Base Rates $
1	Flow Through Adjustments			
2	Book/Tax Depreciation, Net		685,758	685,758
3	Book Depreciation- Net Salvage Amtz		4,671,182	4,864,331
4	Property Removal Costs - ADR Property		(485,311)	(485,311)
5	Loss on Retirement - ACRS/MACRS Removal Costs		(2,272,025)	(2,272,025)
6	Repairs Basis Difference		5,599,492	5,599,492
7	Interest on Debt	2/	(22,765,132)	(26,197,271)
8	Political Action Expenses (Sec. 162E)		0	0
9	Employee Business Expense Disallowance		160,000	160,000
10	OPEB-Federal Medicare Subsidy		(26,292)	0
11	Employee Stock Purchase Plan		600	600
12	Rent Expense - Luxury Autos		900	900
13	AFUDC Equity		0	0
14	Penalties		-	-
15	Total Flow Through Adjustments		(14,430,828)	(17,643,526)
16	Deferred Adjustments			
17	Excess Tax Depreciation Over Book	3/	(10,693,034)	(7,140,593)
18	Repairs on Gas Pipeline		(49,796,667)	(34,416,200)
19	Bonus Depreciation		(46,676,917)	(25,358,250)
20	Sec 263a Mixed Service Costs		(10,105,417)	(10,961,500)
21	Avoided Cost Interest		(103,448)	(103,448)
22	Loss on Retirement - ACRS/MACRS Property Basis		(1,817,179)	(1,817,179)
23	Capitalized Legal Expenses - RAR		-	-
24	Builder Incentives Capitalized		(49,773)	(49,232)
25	Stored Gas Losses		2,998	2,998
26	Contributions In Aid of Construction		449,208	449,208
27	Legal Liability-Leased Headqtrs Bldg		166,709	166,709
28	LIFO Inventory Adj		16,344,487	16,344,487
29	Capitalized Inventory		-	-
30	Customer Advances		500,000	500,000
31	Other		-	-
			-	-
32	Total Deferred Adjustments		(80,392,965)	(48,101,814)
33	Total Statutory Adjustments		(94,823,793)	(65,745,340)

1/ Unless otherwise noted, amounts are derived from historical patterns or averages.
2/ See Exhibit No. 102, Sch. 3, Page 4.
3/ See Exhibit No. 107, Page 3.

COLUMBIA GAS OF PENNSYLVANIA, INC.

CALCULATION OF FEDERAL AND STATE INCOME TAXES
PRO FORMA AT PROPOSED BASE RATES
FTY = FUTURE TEST YEAR TME 5/31/13, FFRY = FULLY FORECASTED RATE YEAR PERIOD ENDED JUNE 30, 2014

Line No.	Description	Pro Forma At Historic Test Year Base Rates (1) $	Pro Forma At Forecasted FTY Base Rates (2) $	Pro Forma At Forecasted FFRY Base Rates (2) $	Pro Forma At Forecasted Proposed Base Rates (3) $
1	Operating Income Before Income Taxes (Exh. 102, Sch.3, Pg 3)	64,646,387	58,335,901	48,519,736	120,735,863
2	Pennsylvania Corporate Net Income Tax Deductible (P20, L8)	5,418,894	(185,811)	117,298	(5,917,434)
3	Statutory Adjustments				
4	Flow-Through Adjustments				
5	Book/ Tax Depreciation, Net	338,702	685,758	685,758	685,758
6	Book Depreciation- Net Salvage Amtz	2,958,551	4,671,182	4,864,331	4,864,331
7	Property Removal Costs - ADR Property	(556,755)	(485,311)	(485,311)	(485,311)
8	Loss on Retirement - ACRS/MACRS Removal Costs	(2,642,826)	(2,272,025)	(2,272,025)	(2,272,025)
9	Repairs Basis Difference	3,254,425	5,599,492	5,599,492	5,599,492
10	Interest on Debt (1)	(21,048,713)	(22,765,132)	(26,197,271)	(26,197,271)
11	OPEB - Federal Medicare Subsidy	(13,385)	(26,292)	0	-
12	Employee Business Expense Disallowance	172,227	160,000	160,000	160,000
13	AFUDC Equity	0	0	0	-
14	Employee Stock Purchase Plan	593	600	600	600
15	Rent Expense - Luxury Autos	1,066	900	900	900
16	Total Flow Through Adjustments	(17,536,115)	(14,430,828)	(17,643,526)	(17,643,526)
17	Deferred Adjustments				
18	Excess Tax Depreciation Over Book	267,666	10,693,034	7,140,593	7,140,593
19	Repairs on Gas Pipeline	(5,913,014)	(49,796,667)	(34,416,200)	(34,416,200)
20	Bonus Depreciation	(60,824,000)	(46,676,917)	(25,358,250)	(25,358,250)
21	Sec 263a Mixed Service Costs	(3,945,833)	(10,105,417)	(10,961,500)	(10,961,500)
22	Loss on Retirement - ACRS/MACRS Property Basis	(1,540,742)	(1,817,179)	(1,817,179)	(1,817,179)
23	Avoided Cost Interest	1,459	(103,448)	(103,448)	(103,448)
24	Capitalized Legal Expenses - RAR	0	-	-	-
25	Builder Incentives Capitalized	(49,321)	(49,773)	(49,232)	(49,232)
26	Stored Gas Losses	1,977	2,998	2,998	2,998
27	Contributions In Aid of Construction	55,127	449,208	449,208	449,208
28	LIFO Inventory Adj	(47,280,415)	16,344,487	16,344,487	16,344,487
29	Capitalized Inventory	(1,791,687)	-	-	-
30	Legal Liability-Leased Headqtrs Bldg	164,358	166,709	166,709	166,709
31	Customer Advances	65,997	500,000	500,000	500,000
32	Total Deferred Adjustments	(120,788,428)	(80,392,965)	(48,101,814)	(48,101,814)
33	Taxable Income (Lines 1,2,16,32)	(68,259,262)	(36,673,703)	(17,108,306)	49,073,089
34	Federal Income Tax Payable @ 35%	(23,890,742)	(12,835,796)	(5,987,907)	17,175,581
35	Deferred Income Taxes (Line 32 @ 35%)	42,275,950	28,137,538	16,835,635	16,835,635
36	Tax Refund Amortization	(10,652,274)	(14,914,440)	(4,089,420)	(4,089,420)
37	Flow Back Of Excess Deferred Taxes	(309,311)	(628,368)	(628,368)	(628,368)
38	Effect of CNIT Deferred Tax on FIT (P17, Lines 9-13 @35%)	(1,707,752)	(548,174)	(548,174)	(548,174)
39	Net Federal Income Tax Expense (Lines 34-38)	5,715,871	(789,240)	5,581,766	28,745,254
40	State Income Tax Expense (P17, L14)	(539,603)	1,752,021	1,448,912	7,483,644
41	Income Tax Expense Before Consolidated Tax Savings	5,176,268	962,781	7,030,678	36,228,898
42	Consolidated Tax Savings Adjustment	0	0	0	0
43	Total Income Tax Expense	5,176,268	962,781	7,030,678	36,228,898

(1) Interest expense for rate purposes has been calculated as follows: 2.660% weighted cost of short-term and long-term debt x original cost rate base of $800,331,300 = $22,765,132

COLUMBIA GAS OF PENNSYLVANIA, INC.

CALCULATION OF FEDERAL AND STATE INCOME TAXES
PRO FORMA AT PROPOSED BASE RATES
FTY = FUTURE TEST YEAR TME 5/31/13, FFRY = FULLY FORECASTED RATE YEAR PERIOD ENDED JUNE 30, 2014

Line No.	Description	Pro Forma At Historic Test Year Base Rates (1) $	Pro Forma At Forecasted FTY Base Rates (2) $	Pro Forma At Forecasted FFRY Base Rates (2) $	Pro Forma At Forecasted Proposed Base Rates (3) $
1	Calculation of Pennsylvania Corporate Net Income Tax				
2	Operating Income Before Income Taxes (Page 19, Line 1	64,646,387	58,335,901	48,519,736	120,735,863
3	Statutory Adjustments (Page 19, Lines 16 & 32)	(138,324,543)	(94,823,793)	(65,745,340)	(65,745,340)
4	Pennsylvania Bonus Depreciation Adj	19,434,973	41,347,859	19,051,448	19,051,448
5	CNIT Taxable Income	(54,243,183)	4,859,967	1,825,844	74,041,971
6	Net Operating Loss Deduction	0	3,000,000	3,000,000	14,808,394
7	PA Taxable Income	(54,243,183)	1,859,967	(1,174,156)	59,233,577
8	CNIT Payable at Base Rate of 9.99%	(5,418,894)	185,811	(117,298)	5,917,434
9	Deferred Tax On Net Operating Loss Deduction (amounts from above @ 9.99%)	0	0	0	0
10	Deferred Tax On Inventory Adj	4,723,313	1,632,814	1,632,814	1,632,814
11	Deferred Tax on Capitalized Inventory	178,990	0	0	0
12	Deferred Tax On Legal Liability-Leased Headqtrs Bldg	(16,419)	(16,654)	(16,654)	(16,654)
13	Deferred Tax On Customer Advances	(6,593)	(49,950)	(49,950)	(49,950)
14	Pennsylvania Corporate Income Tax Expense	(539,603)	1,752,021	1,448,912	7,483,644

COLUMBIA STATEMENT NO. 112-R

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

GREGORY L. SHOEMAKER

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. My name is Gregory L. Shoemaker, and my business address is 200 Civic Center Drive, Columbus, Ohio 43215.

Q. By whom are you employed and in what capacity?

A. I am employed by NiSource Corporate Services Company ("NCSC") as a Lead Financial Analyst.

Q. Please describe your educational and professional background.

A. I received a Bachelor of Science degree in 1996 from The Ohio State University in Columbus, Ohio. In May 2004, I received a Masters Degree in Business Administration from Franklin University in Columbus, Ohio. I was hired by NCSC in February 2001 as a Financial Analyst, a position that I held until October 2006. From October 2006 through July 2007, I was employed by International Business Machines as a Senior Business Process Analyst, a position in which I performed various accounting duties. In July 2007, I rejoined NCSC where I held various accounting positions ranging from Senior Financial Analyst to Lead Financial Analyst.

Q. What are your duties as a Lead Financial Analyst for NCSC?

A. As a Special Studies Lead Financial Analyst of NCSC, my principal responsibilities include assisting in overseeing the general books and records of NCSC. In addition, I am responsible for overseeing the annual filing of the Form 60 and completing other ad hoc accounting projects. In carrying out these duties, I am responsible for a number of activities including:

(1) Assisting in the maintenance of the accounting system that identifies

the costs for services that are subsequently billed to NiSource Inc. ("NiSource") affiliates;

(2) Developing accounting data, providing testimony, and responding to requests from regulatory bodies with regard to NCSC billing on behalf of the NiSource affiliates.

Q. Did you submit Direct Testimony in this proceeding?

A. No, I did not.

Q. What is the purpose of your Rebuttal Testimony?

A. I will respond to the direct testimony of Christine Wilson filed on behalf of the Bureau of Investigation and Enforcement regarding Business Promotion Services and Thomas S. Catlin on behalf of the Office of Consumer Advocate regarding NCSC labor and benefits and GEAC costs.

Q. These were matters covered in the Direct Testimony of Witness Summer D. Cogar in Columbia Statement No. 12. Why are you addressing these issues on rebuttal?

A. Ms. Cogar recently left NCSC to pursue an opportunity with another company.

Q. Are you familiar with Columbia Statement No. 12 that has been submitted in this proceeding?

A. Yes, I am. I worked with Ms. Cogar at the time she prepared Columbia Statement No. 12, and I was involved in the internal review of her testimony before it was submitted.

Q. Are you, then, adopting Columbia Statement No. 12 as your own testimony in this matter?

A. Yes, I am.

Q. If you were asked the same questions that appear in Columbia Statement No. 12, would the substance of your answers be the same as those provided by Ms. Cogar?

A. Yes.

Q. Are you also sponsoring Exhibit No. SDC-1, Exhibit SDC-2, Exhibit SDC-3, and Exhibit SDC-4 that were attached to, and submitted with, Columbia Statement No. 12?

A. Yes. I am now sponsoring those exhibits and I adopt them as my own.

Q. What issues would you like to address on rebuttal in this matter?

A. I will address the following areas:

- System Svcs. – Business Promotion Services
- NCSC Labor and Benefits
  - Percentage of labor costs allocated to Columbia Gas of Pennsylvania, Inc. ("CPA")
  - Costs for additional employees
  - Annualized costs as of the end of the rate year
- GEAC costs

System Svcs. – Business Promotion Services

Q. What is I&E witness Christine Wilson's recommendation regarding the Company's claim related to System Svsc. – Business Promotion Services?

A. Christine Wilson recommends that expense of $1,608,646 and capital of $471,187 for a total of $2,079,833 be denied from the claim for Business Promotion Services on the basis that the costs are only related to promotion of the

Company's image or the use of natural gas.

Q. Do you agree with I&E witness Christine Wilson's recommendation?

A. No, I do not agree with this recommendation.

Q. Please explain.

A. The activities underlying the Business Promotion costs include the coordination of new, conversion and added load customers in the markets served by NiSource, including Columbia Gas of Pennsylvania. In addition, the costs reflected under Business Promotion include the maintenance of service to the Company's largest customers, acting as a single source contact for those largest industrial and commercial customers ongoing natural gas needs, questions, issues, and natural gas related work and projects. Employees included in this category provide cost analysis and information to customers regarding products and services. The cost analysis provided to customers is related to the following items: conversion from alternate fuels to natural gas, service requirements for new construction of homes and businesses, as well as comparisons from alternative fuels to natural gas. Further, these employees spend a great deal of time educating customers on energy efficiency and conservation, as well as natural gas safety which allows customers/rate payers to make educated choices regarding energy efficiency and conservation. Through the work and expenses of these employees, adding new customers, and serving the ongoing needs of the largest industrial and commercial customers benefits CPA ratepayers. Specifically, each customer that connects new natural gas service or each large customer that continues or expands its use of natural gas helps spread the cost to serve. Further, by having

these services provided through NCSC, CPA and its customers benefit from the economies of scale achieved via a centralized system for all NiSource affiliates.

NCSC Labor and Benefits

Q. What is OCA witness Thomas S. Catlin's recommendation regarding the Company's claim related to NCSC Labor and Benefits?

A. Thomas S. Catlin recommends three adjustments related to NCSC Labor and Benefits for a total reduction of $1,101,160 to the Company's claim. The three adjustments are related to: (1) a reduction of labor percentage allocated to CPA; (2) costs attributed to new employees; and, (3) annualized costs at the end of the Fully Forecasted Rate Year ("FFRY").

Q. Do you agree with OCA witness Thomas S. Catlin's recommendation regarding the reduction of the labor percentage allocated to CPA from 11.2% to 10.9%, which reduces the claim by $488,858?

A. No, I do not agree with this recommendation.

Q. Please explain.

A. The CPA allocated labor rate of 11.2% for the month of May 2012 was used since it reflected the most current composition of employee costs when the original schedules were created. The most current data available to NCSC at filing, months June-August 2012, further validated using the May 2012 data as the average percentage was 11.2%. In addition, the use of the most recent data is consistent with the approach used in prior rate cases to support the allocated labor percentage. Moreover, the data for the months June 2012 through December 2012 provide additional support for the Company's proposed allocated

labor percentage as it also reflects an allocated labor percentage of 11.2%. (See Exhibit GLS-1R.) The data in Exhibit GLS-1R supports the percentage used in the claim instead of using a trailing average proposed by witness Catlin to determine the allocated labor percentage.

Q. Do you agree with OCA witness Thomas S. Catlin's recommendation regarding the reduction of the cost for additional service company employees projected to be hired during the FFRY, which reduces the claim by $325,511?

A. No, I do not agree with this recommendation.

Q. Please explain.

A. As of December 4, 2012, when Columbia responded to I&E-RE-113-D, the Company provided information related to the hiring process through November 30, 2012. Since that time, NCSC has gathered additional information related to incremental full time employee increase. Specifically, 11 additional positions listed on I&E-RE-113-D Attachment A have been filled since the last update and the hiring process has continued to move forward with additional job postings and interviews. In the claim, 86 employees were projected to be added during the FTY ended May 31, 2013, but there has been a 102 incremental increase in full time employees in NCSC from June 2012-December 2012. Since the time the case was filed, additional incremental positions have been created and filled but were not included in the claim. These additional positions include: additional GIS Engineering Technicians, Welder and assembler at the Bangs Fabrication Shop, along with various Analysts and Administrative Assistants. The increase in full time employees demonstrates that NCSC is on schedule to hire a total of 113

employees before the midpoint of the rate year of December 2013.

Q. Do you agree with OCA witness Thomas S. Catlin's recommendation regarding the reduction of the costs annualized as of the end of the FFRY on June 30, 2014, which reduces the claim by $286,792?

A. No, please refer to the rebuttal testimony of Columbia witness Krajovic, Statement No. 106-R, for the Use of the Fully Forecasted Rate Year.

GEAC Costs

Q. What is OCA witness Thomas S. Catlin's recommendation regarding the Company's claim related to GEAC Costs?

A. Thomas S. Catlin recommends eliminating the GEAC support and maintenance costs that are included in NCSC billings, since the NiFit system will replace the GEAC software package.

Q. Do you agree with OCA witness Thomas S. Catlin's recommendation regarding the reduction of the GEAC support and maintenance costs, which reduces the claim by $46,919?

A. No, I do not agree with this recommendation.

Q. Please explain.

A. When the NiFit project is completed per witness Fontaine Statement No. 13, page 4, lines 4-13, additional support and maintenance costs will be incurred for the NiFit project that were not included in the claim. The NiFit claim in the case is for the amortization of one time start up costs. The costs for GEAC were left in the claim since it would be difficult to estimate the future support and maintenance costs associated with the NiFit project. Furthermore, not all costs

associated with the GEAC system will go away completely when it is replaced by the NiFit project projected as April 2014. The GEAC system will not be used to enter new data, but will be maintained to retrieve historical detailed data. This would be a less expensive approach than converting all GEAC data and reports into the new system.

Q. Does this conclude your prepared rebuttal testimony?

A. Yes.

Exhibit GLS-1R
Schedule 1
Percentage of labor allocated to Columbia Gas of Pennsylvania, Inc.

	Month	CPA %
	(A)	(B)
1	Jun-12	10.8%
2	Jul-12	11.2%
3	Aug-12	11.5%
4	Sep-12	11.3%
5	Oct-12	11.2%
6	Nov-12	12.1%
7	Dec-12	10.3%
8	Average	11.2%

COLUMBIA STATEMENT NO. 115-R

2-13-13
Hbg SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

PAULA A. STRAUSS

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

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Q. Are you the same Paula A. Strauss that filed Direct Testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. In my rebuttal testimony, I respond to revenue allocation and rate design issues raised by I&E Witness Jeremy B. Hubert, OSBA Witness Robert D. Knecht, OCA Witness Glen A. Watkins, CAUSE-PA Witness Eugene M. Brady, CAAP Witness Susan A. Moore-Wychulis and NGS Witness James L. Crist.

I. Response to Jeremy B. Hubert, I&E Statement No. 3

Q. On page 23, lines 4 through 18 of I&E Statement No. 3, Witness Hubert recommends that the Commission rely on the cost of service study that is based on allocating mains based on the Peak & Average method. Do you agree with relying on a single class cost of service study?

A. No. A single class cost study should not be relied upon for revenue allocation and rate design. The Company considers a range of class cost study results in the process of designing rates. The Class Cost of Service Studies developed by Company Witness Skirtich (Columbia Statement No. 9) were used to evaluate the reasonableness of the Company's proposed revenue allocation. The results of the Customer / Demand Study and Peak & Average Study provide a range of costs to serve each customer class. Witness Skirtich also developed an Average Study showing a combination of the two class cost studies and this is the study that the Company relied upon most for the revenue allocation and rate design process.

Q. Has Witness Hubert presented a method for scaling back rates?

A. Yes. On pages 27 through 29 of his Direct Testimony, Witness Hubert presents a recommendation to scaleback the class revenue requirements if the Commission approves less than the Company's requested revenue requirement increase. He recommends that the first $200,000 be used to reduce the revenue increase for the Small Distribution Service ("SDS") customers and the next $6,000,000 reduction be allocated to the residential customers. Any remaining revenue requirements reduction would be allocated to customer classes, excluding LDS and MDS using I&E Exhibit No. 3, Schedule 8, page 3, line 20.

Q. Does the Company oppose Witness Hubert's scaleback method?

A. The Company does not oppose Witness Hubert's scaleback method. Either Witness Hubert's proposal or a prorated allocation of the scaleback amount would be acceptable to the Company.

Q. Refer to page 44, lines 14 through 17 of Witness Hubert's Direct Testimony. Please comment on Witness Hubert's statement that the Company "steadfastly defends a distribution rate structure that penalizes customers who are able to lower usage."

A. I do not agree that the Company's residential rate design proposals penalize customers who lower their usage. In fact, given the Company's proposal for a Revenue Normalization Adjustment (also referred to as "RNA" in this testimony), customers are able to experience savings as a result of their own conservation efforts. Please refer to Exhibit PAS-1R (pages 1 and 2) for hypothetical examples of how residential customers could experience savings through conservation

efforts. Witness Hubert's assertion ignores the fact that the majority of the Company's costs to provide distribution service to residential customers are not variable in nature and his assertion presupposes that it is less expensive for the Company to serve a residential customer when the customer reduces usage. This simply is not true. Any "savings" that a residential customer experiences in distribution rates from reducing consumption is a loss to the Company because the costs to serve residential customers do not decrease when a residential customer's usage decreases. Additionally, the Company's proposed Revenue Normalization Adjustment would reflect, on a timely basis, what normally happens in the rate case process when customers implement conservation measures. If usage is reduced due to conservation, then in the Company's next rate case, fixed costs are spread over lower volumes and rates for all residential customers increase because there are fewer volumes.

Q. Please describe the hypothetical example provided on page 1 of Exhibit PAS-1R.

A. The calculations shown on page 1 of Exhibit PAS-1R demonstrate that residential customers implementing conservation measures retain the opportunity to experience savings on their gas bills under the RNA. This example uses the normalized monthly consumption for an average residential customer for the twelve month period ended May 2012 and the Company's primary rate design proposal, which includes a customer charge of $19 and a distribution charge of $3.8621. The gas supply charge is held constant at $4.3212 to be consistent with the level of gas supply costs included in Exhibit No. 103. Columns 1 through 8

and lines 1 through 13 show the calculation of the monthly bills for this average residential customer. The total annual bill, $936.84, is shown in column 8.

Q. Explain columns 9 through 12 of Exhibit PAS-1R.

A. These columns show three possible conservation measures that residential customers could choose to implement. The measures in this example include a furnace replacement to increase efficiency, attic insulation and wall insulation. Other conservation measures would be equally applicable to this calculation. For the purpose of the example on page 1, I have assumed that a residential customer could save a total of 31 Dth annually if all three measures were implemented. Individually, the attic and wall insulation could produce savings of 10 Dth each and the furnace replacement results in an assumed savings of 11 Dth annually. On line 13, potential conservation savings from each measure is computed as the product of the Dth savings and the sum of the gas supply charge and the distribution charge. Next, on lines 15 through 19, two RNA Scenarios are depicted.

Q. Please describe the results of RNA Scenario A and RNA Scenario B.

A. In Scenario A, I assumed a hypothetical RNA rate of $0.25 per Dth. For simplicity, I used the same RNA rate for the entire annual period, instead of different RNA rates for Period 1 and Period 2. Line 15 shows the RNA rate multiplied by the annual Dth minus the Dth savings that would be experienced with each conservation measure. This amount would be paid by the customer through the RNA charge over the period of one year. The resulting annual savings due to the installation of each conservation measure is shown on line 16

for Scenario A. The same computations are repeated on lines 18 and 19 with a Revenue Normalization Adjustment of $0.75 per Dth. This analysis shows a wide range of hypothetical RNA values to illustrate that even with a relatively high RNA in a certain period, residential customers could still experience the benefits of installing conservation measures. Additionally, it is important to recall that many factors will influence the precise RNA factor that is billed to residential customers and the RNA factor could be a credit on customers' bills.

Q. Please explain page 2 of Exhibit PAS-1R.

A. Page 2 of Exhibit PAS-1R is being provided to show a second scenario concerning annual usage for a residential customer. On page 2, the monthly usage has been increased by 40% over the average residential customer's usage. Likewise, the hypothetical annual Dth reductions that could be achieved by this higher use residential customer have been increased. On page 2, the furnace replacement and wall insulation both have an assumed potential savings amount of 19.9 Dth. The saving for the attic insulation is assumed to be 14.9 Dth. As demonstrated by this scenario with the Company's RNA proposal, a higher than average use residential customer could experience considerable savings by implementing conservation measures.

Q. On page 46, lines 9 through 18, Witness Hubert presents his recommendation for Columbia's residential rate structure. Does Columbia oppose Witness Hubert's recommended residential rate design?

A. In general and with the inclusion of the Revenue Normalization Adjustment, Columbia does not oppose the residential rate design presented by Witness

Hubert. The Company supports eliminating the 2.1 Dth per month allowance in the fixed monthly charge with the caveat that the fixed charge must increase to maintain the same percent of revenues collected through a fixed charge, unless a Revenue Normalization Adjustment is approved. Additionally, Columbia would be willing to accept a customer charge lower than actual customer costs, if and only if the Revenue Normalization Adjustment is implemented.

Q. Would Columbia accept Mr. Hubert's proposed customer charge without the RNA mechanism?

A. No. Witness Hubert's residential customer charge is not cost based and does not provide the revenue stability of the Company's current residential rate design.

Q. Refer to page 47, lines 8 through 14 of Witness Hubert's Direct Testimony. Witness Hubert states the following:

> *Thus, even if after the enactment of Act 11 the Commission determines greater revenue stability is required through the RNA, allowing an adjustment to reflect potential declines in usage will have the least impact on customers while still affording the Company revenue stability. In addition, any increase in the average usage per customer, such as occurred in 2007 and 2010, will reduce customers' usage rates, preventing the Company from receiving a windfall and benefitting the customer.*

Do you have any comments related to these statements presented by Witness Hubert?

A. Yes. First, I disagree with Witness Hubert that both Act 11 and a Revenue Normalization Adjustment provide the Company with an opportunity to stabilize revenues. As Company witness Kempic explained in his direct testimony in this proceeding, Act 11 addresses the *timeliness* of recovery of the Company's investments while Revenue Normalization Adjustments and modern rate designs

address the *certainty* or the *stability* of revenue recovery. An analogy would be a landlord who has historically established the tenant's annual rent based on past expenditures and capital improvements. That type of rent calculation is always behind the times because it is based on past expenses and it does not recognize capital improvements being made when the rent is being paid. Now, if the landlord begins to establish the annual rent based on the expenses and capital improvements that he will make in the future, it will permit the landlord a *more timely* opportunity to recover those expenses and capital improvements as they are being made rather than after the fact. This is the change that Act 11 provided to utilities. However, assume that the tenant has the right to pay rent only when he stays at the property and he is under no obligation to tell the landlord tenant how many days or months he will stay at the property. In that situation, while the landlord has a *more timely* opportunity to recover his investments, there is *no certainty* that he will recovery his investments. This is the situation Columbia is in under Act 11. A Revenue Normalization Adjustment would address the stability of revenue because it is applied to the established base rates to adjust for any variations from "normal." The two impact revenue collections in different manners. Act 11 applies to setting a fair baseline revenue requirement and the Revenue Normalization Adjustment would be implemented to ensure that the Company does not collect more or less than the fair baseline revenue requirement set during a base rate proceeding. As Witness Hubert states, the implementation of a Revenue Normalization Adjustment will require the Company to give back excess revenues, as well as collect any revenue deficiencies. I agree that the RNA

mechanism provides stability for both the Company and its residential customers, since the Company is giving up the opportunity to earn revenue in excess of the baseline amount established using normal weather in a rate case.

Q. Refer to pages 50-51 of Witness Hubert's Direct Testimony. In this section of his testimony, Witness Hubert addresses low income customer assistance and lower rates of return, as conditions of implementing a Revenue Normalization Adjustment. Does Columbia offer a program to assist low income customers with paying their bills?

A. Yes. Columbia already offers substantial assistance to low income residential customers through its CAP and WarmWise® Low Income Usage Reduction Programs. Columbia also has other programs in place that provide assistance and education to moderate income customers to improve their energy efficiency. Additionally, Company Witness Krajovic addresses Hardship Fund Resources on pages 20 through 23 of her Direct Testimony.

Q. Does Columbia's proposal comprehensively address the rate of return issue raised by Witness Hubert?

A. Yes. After reviewing a list of Columbia's peer group companies, it is my understanding that most of the peer group companies utilized by Witness Moul have already adopted some sort of revenue stabilization mechanism. Please refer to Witness Moul's Rebuttal Testimony for more specific information related to the Company's rate of return proposal.

Q. On page 51, lines 6 through 9, Witness Hubert states the following:

Further, despite what other states have or have not approved, this Commission rightfully remains concerned that customers continue to be able to derive benefits from their conservation efforts, benefits that are greatly reduced by the Company's proposed rate designs.

Will a customer who conserves be able to obtain savings, if a Revenue Normalization Adjustment is implemented?

A. Yes. Please refer to Exhibit PAS-1R for hypothetical examples of how customers could experience savings through conservation measures, if a Revenue Normalization Adjustment is implemented by Columbia. Again, the Company emphasizes that under the RNA residential customers are entitled to enjoy the benefits of their conservation efforts and those benefits are primarily the savings experienced from the reduced consumption of natural gas.

II. Glenn Watkins / Pennsylvania Office of Consumer Advocate ("OCA")

Q. Refer to page 5, lines 4 through 12 of Witness Watkins' Direct Testimony. Do you agree that the Peak and Average method should be considered the "preferred approach" for class cost of service studies?

A. No. Cost of service studies should be used as a guide for revenue allocation and rate design and there is not a single "right" study. As previously stated in my response to Witness Hubert, Witness Skirtich's Average Study provides a combination of CCOS approaches and is an appropriate tool for revenue

allocation and rate design. Witness Skirtich's Average Study provides a combination of the Customer / Demand and Peak & Average methods.

Q. Refer to page 15, lines 11 through 25, of Witness Watkins' Direct Testimony. The following statement begins on line 11:

> *In addition, Ms. Strauss effectively spreads the revenue shortfall resulting from discounted rates available only to certain Commercial and Industrial customers to those classes and customers that are captive to Columbia's distribution system and therefore, do not directly benefit from the discount program.*

Do you agree with Witness Watkins' statement?

A. No. The fundamental flaw in Mr. Watkins' statement is that he assumes his cost of service study is the one and only "right" study, and concludes that the LDS class has a deficiency caused, in substantial part, from discounted rates. While I am not the Company's class cost of service study expert, if other cost allocation studies are considered, the revenues received from the LDS class, including discounted rates, exceed the class' allocated cost of service. This indicates that if the LDS rates were based upon other, more appropriate, cost studies, there would be less of a difference between full tariffed rates and the effective rate of other alternatives, thereby reducing and possibly eliminating the economic need to flex rates to retain these customers. Further, in the revenue allocation process, flex discounts are not spread. Fully Forecasted Rate Year non-gas revenues are used to perform the initial allocation of the revenue requirement for each group being allocated a portion of the increase.

Q. On page 15 of his Direct Testimony, Witness Watkins asserts that flex discounts are similar to CAP and Rider USP, and therefore, *"revenue shortfalls due to*

discounts must remain within the same customer class." Do you agree with Witness Watkins' statements concerning flex and CAP / Rider USP?

A. No. Unlike the benefits associated with CAP / Rider USP, all customers on Columbia's system benefit from the reduced per customer fixed costs due to the existence of flex rates. As explained by Company Witness Phelps, absent the flex rates, customers with competitive alternatives would opt not to take service from Columbia, and as a result, rates for other customers would need to increase to cover fixed costs. Therefore, Witness Watkins' argument that flex and CAP/USP are similar is flawed and should not be considered.

Q. Refer to pages 16 through 18 of Witness Watkins' Direct Testimony. Do you agree with the revenue allocation developed by Witness Watkins?

A. No. As previously stated, a company's revenue allocation should be based upon a range of class cost study results and not a single CCOSS. Witness Watkins is relying solely upon a revised version of the Peak & Average CCOSS and, this is not an acceptable basis for revenue allocation and rate design. I agree with Witness Watkins that mainline service customers should not be assigned a revenue increase. However, as stated above, I do not agree with his treatment of flex rate discounts and the revenue increases that he has allocated to the LGS and LDS customer classes. Witness Skirtich's Average Study, which takes into account the range of CCOSS results, demonstrates that the level of revenue increases proposed by Witness Watkins for the LGS and LDS customer classes is not warranted.

Q. Have you reviewed the results of Witness Skirtich's revised Average Study?

A. Yes, I have reviewed Witness Skirtich's revised Average Study.

Q. Do you recommend any changes to the Company's proposed revenue allocation or rate design based upon the revised Average Study?

A. Not at this time. Please refer to the Rebuttal Testimony of Witness Skirtich (Columbia Statement No. 109-R). On pages 3 and 4, Witness Skirtich states that the corrections and revisions to the class cost of service studies have had limited impact on the range of results produced by the studies. Only the LGS customer class experienced a relatively notable change. In order to mitigate this change, the LGS customer class could be allocated a portion of any scaleback revenue amount, before a reduction is provided to other customer classes.

Q. Do you agree with the scaleback method proposed on page 18 of Witness Watkins' Direct Testimony?

A. No. As stated previously, Columbia is not opposed to using Witness Hubert's scaleback method, possibly with the inclusion of an initial scaleback amount for the LGS customer class, or a prorated allocation of the entire scaleback amount.

Q. Refer to page 19, lines 17 through 19 of Witness Watkins' Direct Testimony. Please comment on Witness Watkins' statement that is shown below:

> *It is clear that the primary objective of Columbia's Residential rate design is to negate virtually all risks associated with serving its Residential customers by guaranteeing its revenues from these customers.*

A. On pages 4 and 5 of his Direct Testimony, Company Witness Kempic clearly states the Company's three major objectives in this rate proceeding. He states the following:

> *Third, Columbia also seeks approval of a change to its residential rate design in order to provide it with more certainty in the revenue received from residential customers.*

The Company does not dispute that revenue stability is a rate design goal. However, Witness Watkins fails to mention that the Revenue Normalization Adjustment and the associated revenue stability provide benefits for residential customers, too. The Company's proposed rate design ensures that residential customers will not overpay for distribution service by including a means for refunding money to residential customers if revenues exceed the rate allowance. The Revenue Normalization Adjustment is balanced. The benefits of the Company's proposed rate design mechanism are recognized by Witness Hubert on page 47 of his Direct Testimony. Witness Hubert states,

> *In addition, any increase in the average usage per customer, such as occurred in 2007 and 2010, will reduce customers' usage rates, preventing the Company from receiving a windfall and benefitting the customer.*

In addition, the Company remains at risk for increases in expenses between rate cases.

Q. Refer to page 20, lines 7 through 14 of Witness Watkins' Direct Testimony. On this page, Witness Watkins' asserts that weather normalization in a revenue requirement calculation reduces an LDC's risk over time. Do you agree with this concept and its applicability to rate making concepts?

A. No. First, Witness Watkins' argument is flawed because he assumes that the risks faced by LDCs, each year, can be mitigated by reduced risks over a period of time. This is simply not true. The Company needs to be provided with an opportunity to earn a fair return, each year, not just over a longer period of time.

Second, Witness Watkins' is wrong to assume that establishing revenue requirements based upon "normal weather" reduces risk in the rate year. Again, the use of "normal weather" to develop a revenue requirement provides the Company with the opportunity to earn a fair return, when all other factors are held constant and weather is close to normal. However, as can be demonstrated by last winter, the current rate process can result in substantially different revenues if actual weather is substantially different from "normal weather."

Refer to Exhibit 10, Schedule 8 of the Company's filing. Witness Efland provides the Historic Test Year normalization reflecting last year's winter weather. Volumes were normalized up 4,002,617 Dth for residential customers and 2,094,423 Dth for commercial customers to account for the warmer than normal weather. Stated in monetary terms, the Company's historic test year experience resulted in lost revenues of approximately $10.68M for residential customers, at the distribution commodity rate of $2.67, and lost revenues of approximately $4.3M for commercial customers, using an average small commercial rate of $2.07. As stated previously in this testimony, Witness Hubert also notes that the winters of 2007 and 2010 varied significantly from normal. Adoption of the Company's proposed Revenue Normalization Adjustment would substantially remove sales variations from this debate. Further, a Revenue Normalization Adjustment would avoid the controversy of use per customer projections, as misstated projections are wiped away in the adjustment process.

Q. On page 21 of his Testimony, Witness Watkins asserts that different class rates of return are appropriate if the residential class has decoupling. Do you agree with his claim?

A. No. First of all, I note that class returns are always approximate and a range of class cost study results should be considered for revenue allocation and rate design. Second, class returns are seldom exactly at unity for any study, since these studies are used to approximate desired results.

Q. Refer to pages 21, line 8, through and page 22, line 9 of Witness Watkins' Direct Testimony. In general, do you agree with Witness Watkins' economic theory argument?

A. No. Witness Watkins mixes the fundamental principles of economic theory applicable in a competitive market with the core tenets of a monopolistic structure to arrive at conclusions that are flawed due to his combination of "apples" and "oranges." For example, unlike competitive markets, Columbia is not free to set its prices at what the market will bear for all its customers, and Columbia cannot choose to discontinue service in response to either short-term or long-term economic circumstances.

Q. Do you agree with any part of Witness Watkins economic theory argument?

A. Yes. I agree that public utilities are considered monopolies and should be regulated. However, Witness Watkins' conclusion that *"...the guarantee of revenue recovery severely contradicts basic economic philosophy,"* is not applicable to Columbia's residential rate design proposal. The Revenue Normalization Adjustment proposed by Columbia only provides revenue stability

for factors which are beyond the Company's control, such as weather and residential usage patterns. The Company must still control its O&M and manage its capital investment in a prudent manner. Moreover, as explained in the Direct Testimony of Company Witness Kempic, numerous regulatory jurisdictions disagree with Witness Watkins' beliefs about "basic economic philosophy" and have adopted revenue decoupling.

Q. Refer to page 24, line 5 through 12 of Witness Watkins' Direct Testimony. Do you agree that the Company's proposed Revenue Normalization Adjustment *"would penalize those customers that actively and aggressively conserve their natural gas usage?"*

A. No. As stated above, the proposed Revenue Normalization Adjustment would reflect, on a timely basis, what normally happens in the rate case process when customers implement conservation measures. If usage is reduced due to conservation, then in the Company's next rate case, fixed costs are spread over lower volumes and rates for all residential customers increase because there are fewer volumes. Additionally, Exhibit PAS-1R provides a numerical example of how residential customers may benefit from implementing conservation measures. A complete description of Exhibit PAS-1R is included above as part of this testimony. Also, as stated above, the current residential rate design provides customers who reduce their consumption with lower distribution charges even though the Company's costs to serve them do not decrease when customers' consumption decreases. To be fair, a rate design should recover the Company's revenue requirement associated with providing service to residential customers

consistent with the Company's costs of providing service. The Revenue Normalization Adjustment provides this consistency and equity by allowing the Company to recover a baseline revenue per residential customer. Revenue above the baseline is refunded and, revenue below the baseline is collected in a future period.

Q. Refer to page 24, lines 13 through 23 of Witness Watkins' Direct Testimony. Please comment on Witness Watkins' statements concerning the timing lag of recovering revenue difference on a seasonal basis.

A. The Company's proposed Revenue Normalization Adjustment is designed to recover revenue differences over the same months in which the differences occurred. While this recovery timing does result in a lag, it also prevents a winter deficit or surplus from being collected or refunded in summer months when usage is substantially lower.

Q. Is the Company opposed to limiting the rate variation that would be allowed through the RNA?

A. No. In order to prevent substantial rate differentials due to any unforeseen extreme circumstances, the Company is not opposed to limiting the rate variation that would be allowed through the Revenue Normalization Adjustment. The amount above any predetermined limit would be deferred for future recovery.

Q. On page 24, Witness Watkins expressed concern with establishing "seasonal" revenue requirements. Is the Company opposed to a monthly Revenue Normalization Adjustment?

A. No. The Company is open to providing the Parties and the Commission with options for implementing a Revenue Normalization Adjustment and is not opposed to a monthly Revenue Normalization Adjustment. The Company had believed that the Parties and the Commission would have desired a seasonal design to mitigate any perceived impact with the RNA, but the Company would be willing to move to a monthly RNA to satisfy the Parties and the Commission.

Q. At the top of page 25, Witness Watkins states that *"if customer growth patterns change and/or utilization does not decline as forecasted by the Company, future RNA's are likely to be overstated."* Is Witness Watkins' statement true?

A. No. The Revenue Normalization Adjustment proposed by the Company accounts for unpredictable usage pattern changes. The RNA relies on revenue per customer, not usage per customer and this is one of the key benefits of this rate design mechanism. Once a revenue requirement is set through a rate case proceeding, then a baseline revenue per customer is established. As described in my Direct Testimony, the Company will refund any amount over the baseline revenue per customer and will be allowed to collect any amount below the baseline revenue per customer. Hence, the Revenue Normalization Adjustment is fair to both the Company and its customers and the revenues are not impacted, if use per customer does not develop as projected by the Company.

Q. Refer to page 25, lines 18 through 21 of Witness Watkins' Direct Testimony. He states the following:

In addition, and similar to the RNA option, there will be no detailed review or scrutiny of WNA surcharges and credits as those will be calculated and implemented outside of a rate case with no true-up mechanism

Witness Watkins states a similar concern directly related to the RNA on page 24. Please respond to his concerns.

A. Witness Watkins raises two concerns in his statements. Both of these items, review of a WNA or an RNA mechanism and a true-up of charges or credits have been handled by numerous LDCs and will not be difficult to implement. Columbia would be willing to submit filings and report relevant information for either a WNA or an RNA. An example of the information submitted by Columbia Gas of Kentucky, as part of its WNA, was attached to my Direct Testimony as Exhibit PAS-1. Also, Columbia's affiliates, Columbia Gas of Virginia and Columbia Gas of Massachusetts, submit filings for their respective RNA mechanisms in Virginia and Massachusetts. Additionally, the Company does not oppose a true-up for its Revenue Normalization Adjustment.

Q. Refer to page 25, lines 10 through 21 of Witness Watkins' Direct Testimony. Is Columbia opposed to revising its WNA or RNA proposal to include a dead band?

A. Columbia does not object to modifying its proposed RNA and including a dead band. The Company's initial rate design proposal did not include features, such as a dead band, in an effort to keep the rate design proposal as simple as possible.

Q. Refer to page 27 of Witness Watkins' Direct Testimony. Please describe the chart presented by Witness Watkins.

A. Witness Watkins' chart provides a summary of the monthly usage of Columbia's residential customers for the twelve month period ended May 2012. The Company provided Witness Watkins with this residential customer data in response to discovery request OCA V-22 and he developed the chart in his Direct Testimony. The chart shows the total number of bills for each month and the number of bills including less than 2.1 Dth per month, which is the minimum usage included in the residential customer charge. The last column of the chart displays the percentage of bills with less than 2.1 Dth for each month.

Q. Do you agree with Witness Watkins' description of the monthly spread of the data?

A. Yes. Approximately, three-quarters of all residential customers consumed less than the minimum threshold during the summer months of July, August and September. The "vast majority" of all residential customers exceed the minimum usage threshold during the three coldest winter months of January, February and March.

Q. Please comment on Witness Watkins' residential data summary.

A. The chart in Witness Watkins' Direct Testimony provides a meaningful summary of residential usage data, which supports the need for a rate design change. The Company's existing rate design is providing revenue stability in the summer months, when there is little need. Usage volatility overwhelmingly occurs in the winter months, and traditional rate design does nothing to respond to these fluctuations. Further, the Company's existing rate design does nothing to

minimize this volatility in usage patterns. The Company's proposed Revenue Normalization Adjustment is designed to respond to this type of usage variability and provides a balanced approach for both Columbia and its residential customers.

III. Robert D. Knecht / Pennsylvania Office of Small Business Advocate ("OSBA")

Q. Refer to pages 42 through 44 of Witness Knecht's testimony. Please describe Witness Knecht's recommendation concerning flex rate customers.

A. Witness Knecht recommends that the Company move "NGDC Bypass" customers to regular tariff rates. The discounts for "NGDC Bypass" customers would be eliminated according to Witness Knecht's proposal. He states that the issue of "NGDC Bypass" should not be deferred pending resolution of the Commission's generic proceeding. Further, he recommends the following:

> *...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 customer a below full-tariff rate.*

Q. Is Witness Knecht's recommendation concerning NGDC Bypass flex customers possible to implement in this proceeding?

A. No. I have been advised by Counsel that the Commission cannot in the context of Columbia's rate case prevent other companies from serving these flex customers under their own tariffs, including flex rate tariffs. This is the reason why parties in the last case agreed to a process whereby the issue of NGDC competition would

be looked at generically. If the Company is required to set rates for these customers at full tariff rates, then in this rate case, it must be accepted that Columbia will lose all of these customers, as there is not a basis to believe that the Company can continue to serve these flex customers at full tariff rates. This is the same logic as to why there is an uncollectible allowance in rates. If it was assumed that the Company would get full revenues from every customer, even though it is known that there will be customers who do not pay their full bills, then the Commission would be depriving the Company of an opportunity to recover its approved revenue requirement.

Q. Do you agree with Witness Knecht's revenue allocation recommendation?

A. Not entirely.

Q. Please elaborate.

A. As Witness Knecht notes on page 2 of his Direct Testimony, his recommendations to the small general service classes are generally consistent with those presented by the Company. However, his revenue allocation proposal for residential and larger industrial customer classes differs from the Company's position. Witness Knecht's revenue allocation proposal for these customer classes includes moving "NGDC Bypass" customers to full tariff rates. As stated above, I disagree with this part of Witness Knecht's proposal and, as a result, I oppose his revenue allocation for residential and larger customer classes.

Q. On page 57 of his Direct Testimony, Witness Knecht proposes that smaller SGSS/SGDS customers should continue to receive the same customer charge and

does not take exception with the Company's proposal for larger SGSS/SGDS customer charges. Do you object to his proposal?

A. Generally, I do not oppose Witness Knecht's proposal for SGSS/SGDS customer charges. However, for simplicity, I recommend establishing a $21.00 customer charge for the smaller SGSS/SGDS customers.

Q. Please refer to pages 36 and 37 of Witness Knecht's Testimony. He argues that the rate of uncollectible is typically much higher for residential customers than for non-residential customers and computes an implied Merchant Function Charge ("MFC") of about 1.7% for residential customers and 0.8% for non-residential customers. Is Columbia opposed to using Witness Knecht's uncollectible percentages in the MFC, instead of the overall 1.46% provided by Witness Gore in his Direct Testimony?

A. No.

IV. Eugene Brady / The Coalition for Affordable Utility Services and Energy Efficiency in Pennsylvania ("CAUSE-PA")

Q. Refer to page 6, lines 3 through 6 of the Direct Testimony of Eugene M. Brady. Please comment on his assertion that the Company is shifting some of its risk onto its residential customers.

A. Witness Brady is viewing Columbia's residential rate design proposal as one sided. In fact, the Company's rate design proposal offers a balanced approach and offers potential benefits to residential customers, not just Columbia. For example, Columbia's proposal for a Revenue Normalization Adjustment includes

the possibility of refunding revenue to residential customers, not just collecting revenue. As explained in my Direct Testimony (Columbia Statement No. 15), the Company would only retain a baseline revenue amount per customer. Any revenue difference from the baseline revenue would be refunded or collected in a future period.

Q. Refer to page 8, lines 12 through 15 of Witness Brady's Testimony. Witness Brady asserts that *"flat fees may diminish the incentive for a household to engage in energy conservation behaviors."* Has Columbia provided an example of how customers may still benefit from conservation behaviors even with higher flat fees and a Revenue Normalization Adjustment?

A. Yes, please refer to Exhibit PAS-1R.

V. Susan A. Moore-Wychulis / Community Action Association of Pennsylvania ("CAAP")

Q. Refer to pages 2 and 3 of Witness Moore-Wychulis' Direct Testimony. Please comment on Witness Moore-Wychulis' statements concerning the Company's rate design proposals and a customer's incentive to conserve.

A. The Company is responding to similar concerns from other Parties. Please refer to Exhibit PAS-1R. A complete explanation of this exhibit is provided in Columbia's response to Witness Hubert. Residential customers are able to experience savings related to conservation measures, particularly with the Company's RNA proposal. The RNA rate design option reflects what happens in the normal rate case process, on a timelier basis. Additionally, it is important to

remember that the RNA approach is balanced in that the Company will refund or collect revenue that varies from an agreed upon baseline revenue per customer.

VI. Gas Cost Procurement Charge (Natural Gas Suppliers / James L. Crist and Office of Small Business Advocate / Robert Knecht)

Q. Refer Witness Crist's testimony, page 19, lines 9 through 13. Do you agree that Columbia's total labor costs need to be revised?

A. Yes. Please refer to Exhibits PAS-2R and PAS-3R for an updated calculation of GPC related labor and benefits and a revised GPC. There was an incorrect formula beginning on line 11 of column 14. This formula was corrected and the revised total labor and benefits expense is $417,219.83. This revised amount has been updated on Exhibit PAS-2R, line 6. The revised GPC based just on this change would be $0.0137 per Dth, which is lower than the filed for GPC of $0.0144 per Dth.

Q. On page 20 his Direct Testimony, Witness Crist proposes that Columbia's labor and benefits amount should be an average of PNG and PECO's costs. Do you agree with Witness Crist's proposal for computing Columbia's labor and benefits?

A. Absolutely not. Each company has different programs, different cost structures, different systems and different corporate structures. These differences can result in varying GPC amounts by company. Columbia used actual data relating to its costs to calculate the GPC. That is the most appropriate method of calculating the GPC.

Q. On pages 47 through 49, Witness Knecht claims that Columbia should include IT costs in the GPC because "NGDs certainly incur some information system costs related to gas procurement." Does the Company oppose Witness Knecht's proposal?

A. No. The Company is willing to add some costs for IT to its GPC.

Q. How do you respond to Mr. Crist's recommendation that 10% of the Company's IT maintenance costs of $12.8 million be allocated to the PGC?

A. Witness Crist provided no basis for the 10% that he used to allocate total IT maintenance costs. Witness Crist references the Company's IT system known as GasSource. The Company has identified Application Support costs related to GasSource and GP1 systems of $53,232, along with Servers and Distributed Storage costs of $56,000, during the Historic Test Year. This is a total cost of $109,232 in the Historic Test Year relating to GasSource and GP1.

Q. Do you recommend that all of these costs be allocated to the GPC?

A. No. Information systems related to gas procurement would be required regardless of the existence of the CHOICE® program. Company Witness Heckathorn is the Company's expert concerning the precise operation of GasSource. The Company recommends an allocation of 73% of these costs to the GPC.

Q. What is the basis for the 73% allocation of these costs?

A. Approximately 27% of Columbia's customers purchase their gas supply from NGSs. Recognizing that GasSource and GP1 are used to support all of our customers, a reasonable approach to allocate a portion of the cost of GasSource

and GP1 to sales service customers through the GPC is to base it on the portion of our customer base taking sales service.

Q. Are there other costs related to GasSource that can be similarly allocated to the GPC?

A. Yes. Please refer to Exhibit PAS-4R for a complete calculation of the total cost of GasSource and GP1 that the Company recommends for allocation to the GPC. The total amount is the sum of application support costs, servers and distributed storage costs, depreciation and a return on capital multiplied by the allocation factor of 73%.

Q. How were the depreciation and return on capital amounts on Exhibit PAS-4R computed?

A. In reviewing the Company's net book value of GasSource and GP1 the monthly depreciation of the capitalized cost of the Gas Management System (GasSource) is $7,542.05 or $90,504.60 annually. Further, the net value of GasSource remaining on Columbia's books is $162,154.18. Columbia's requested pre-tax rate of return of 12.697% was applied to this amount to compute a return of $20,588.72.

Q. How were the IT related costs incorporated into the GPC calculation?

A. The total IT related costs shown on Exhibit PAS-4R were added into the GPC rate calculation presented on Exhibit PAS-2R. The Company's revised GPC proposal of $0.0187 per Dth is shown on this exhibit.

Q. Should working capital costs be reflected in the GPC?

A. No. Witness Krajovic explains why storage working capital costs are properly charged to sales and CHOICE® customers. Witness Krajovic further explains that the Company has no claim for cash working capital associated with gas purchases in this case.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes.

Columbia Gas of Pennsylvania, Inc

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
			Normal	Customer	Distribution	Gas Supply	Total	Possible Conservation Measures*2			Total
line	Year	Month	Usage *1 Dth	Charge $19	Charge $3.8621	Charge 4.3212	Bill [5]+[6]+[7]	Furnace Replaced	Attic Insulation	Wall Insulation	Sum of [9+10+11]
								Hypothetical Annual Dth Reduction			
								11	10	10	31
1	2012	Jan	15.99	$19	$61.75	$69.10	$149.85				
2	2012	Feb	15.86	$19	$61.25	$68.53	$148.79				
3	2012	Mar	15.10	$19	$58.32	$65.25	$142.57				
4	2012	Apr	8.21	$19	$31.71	$35.48	$86.18				
5	2012	May	4.70	$19	$18.15	$20.31	$57.46				
6	2011	Jun	2.39	$19	$9.23	$10.33	$38.56				
7	2011	Jul	1.56	$19	$6.02	$6.74	$31.77				
8	2011	Aug	1.35	$19	$5.21	$5.83	$30.05				
9	2011	Sep	1.43	$19	$5.52	$6.18	$30.70				
10	2011	Oct	2.59	$19	$10.00	$11.19	$40.19				
11	2011	Nov	6.34	$19	$24.49	$27.40	$70.88				
12	2011	Dec	11.10	$19	$42.87	$47.97	$109.83	Conservation Savings			
13	Total	Annual	86.62	$228.00	$334.54	$374.30	$936.84	$90.02	$81.83	$81.83	$253.68
14											
15	Scenario A - Hypothetical RNA Rate A				$0.25	per Dth		$18.91	$19.16	$19.16	$13.91
16	Scenario A - Conservation Savings							$71.11	$62.68	$62.68	$239.78
17											
18	Scenario B - Hypothetical RNA Rate B				$0.75	per Dth		$56.72	$57.47	$57.47	$41.72
19	Scenario B - Conservation Savings							$33.30	$24.37	$24.37	$211.97

Notes:

*1) Refer to Exhibit No. 10, Schedule No. 8, Page 1 of 1; Witness Efland

*2) Columns [9], [10] & [11] show three possible conservation measures and related usage reductions. Row 13 shows the bill reductions that would result and is computed as the distribution rate plus the gas cost rate multiplied by the assumed Dth savings.

Columbia Gas of Pennsylvania, Inc

[1]	[2]	[3]	[4]	[5]	[6]	[7]	[8]	[9]	[10]	[11]	[12]
			Normal	Customer	Distribution	Gas Supply	Total	Possible Conservation Measures*2			Total
line	Year	Month	Usage *1	Charge	Charge	Charge	Bill	Furnace	Attic	Wall	Sum of
			Dth	$19	$3.8621	4.3212	[5]+[6]+[7]	Replaced	Insulation	Insulation	[9+10+11]
								Hypothetical Annual Dth Reduction			
								19.9	14.9	19.9	54.7
1	2012	Jan	22.39	$19	$86.46	$96.73	$202.19				
2	2012	Feb	22.20	$19	$85.75	$95.95	$200.70				
3	2012	Mar	21.14	$19	$81.64	$91.35	$191.99				
4	2012	Apr	11.49	$19	$44.39	$49.67	$113.06				
5	2012	May	6.58	$19	$25.41	$28.43	$72.85				
6	2011	Jun	3.35	$19	$12.92	$14.46	$46.38				
7	2011	Jul	2.18	$19	$8.43	$9.44	$36.87				
8	2011	Aug	1.89	$19	$7.30	$8.17	$34.47				
9	2011	Sep	2.00	$19	$7.73	$8.65	$35.38				
10	2011	Oct	3.63	$19	$14.00	$15.67	$48.67				
11	2011	Nov	8.88	$19	$34.28	$38.35	$91.63				
12	2011	Dec	15.54	$19	$60.02	$67.15	$146.17	Conservation Savings			
13	Total	Annual	121.27	$228.00	$468.35	$524.02	$1,220.37	$162.85	$121.93	$162.85	$447.63
14											
15	Scenario A - Hypothetical RNA Rate A				$0.25	per Dth		$25.34	$26.59	$25.34	$16.64
16	Scenario A - Conservation Savings							$137.51	$95.34	$137.51	$430.98
17											
18	Scenario B - Hypothetical RNA Rate B				$0.75	per Dth		$76.03	$79.78	$76.03	$49.93
19	Scenario B - Conservation Savings							$86.82	$42.16	$86.82	$397.70

Notes:

*1) Refer to Exhibit No. 10, Schedule No. 8, Page 1 of 1; Witness Efland; 40% has been added to the average usage.

*2) Columns [9], [10] & [11] show three possible conservation measures and related usage reductions.
Row 13 shows the bill reductions that would result and is computed as the distribution rate plus the gas cost rate multiplied by the assumed Dth savings.

Columbia Gas of Pennsylvania , Inc
Gas Procurement Charge

1	***Labor and Benefits*** [1]		
2	Accounting Support	$23,497.11	
3	Gas Supply Support	$255,364.51	
4	Legal Support	$30,269.24	
5	Regulatory Support	$108,088.97	
6	Total Labor and Benefits	$417,219.83	
7			
8	Information Technology Systems - Exh PAS - 4R	$160,838.00	
9	Outside Services - Legal Support	$25,521.27	
10			
11	TOTAL (line 6 + line 8 + line 9)	$603,579.00	
12			
13	Total Sales (Therms)	323,191,965 [2]	
14			
15	Gas Procurement Charge (Line 11 / Line 13)	$0.00187	per / therm
16	Gas Procurement Charge (Line 15 * 10)	$0.01870	per / Dth

(1) Labor charges include payroll, benefits and taxes.

(2) Fully Forecasted Rate Year Gas Service Sales per Exhibit 103, page 14, line 26

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-R Exhibit PAS-2R
	(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%	12,319.86
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%	16,104.25
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%	7,219.74
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%	19,117.22
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%	38,761.92
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%	4,190.83
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%	22,051.62
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%	9,362.67
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%	7,906.38
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%	10,519.38
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%	8,509.71
Legal 2	45,060.81	126,419.79	171,480.60	36%				130,212.38	134,118.76	138,142.32	49,239.16	187,381.48	11.50%	21,548 87
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%	210.66
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%	41,083.97
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%	519.40
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%	2,266.24
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%	1,160.23
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%	467.55
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%	25,967.51
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%	14,213.17
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%	748.96
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%	9,511.24
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%	2,738 63
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%	1,269.11
	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**	21.21%	417,219.83

Columbia Gas of Pennsylvania , Inc
Gas Procurement Charge
Information Technology Systems

				Pre - tax Rate of Return	Amount
1	**Gas Source and GP1**				
2	IT Maintenance - GasSource				$53,232.00
3	IT Maintenance - GP1				$56,000.00
4	Depreciation				$90,504.60
5	Return On Capital	$162,154.18	@	12.6970%	$20,589.00
6					
7	Total Gas Procurement Cost of IT Systems				$220,325.60
8					
9	Percent of customers - that do not purchase gas supply from NGSs				73.0%
10					
11	TOTAL (line 7 * line 9)				$160,838.00

COLUMBIA STATEMENT NO. 116-R

2-13-13
Hbg SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

SHIRLEY BARDES HASSON

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. Shirley Bardes Hasson, Southpointe Industrial Park, 121 Champion Way, Canonsburg, PA 15317.

Q. Are you the same Shirley Bardes Hasson that served direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of witnesses Jeremy B. Hubert, filed on behalf of the Bureau of Investigation and Enforcement, Glen A. Watkins, filed on behalf of the Pennsylvania Office of Consumer Advocate, and Robert D. Knecht, filed on behalf of the Office of Small Business Advocate.

Q. What issues will you be addressing in this testimony?

A. I will address the System Charge, the Usage Charge, the Price-to-Compare and the Pass-through Charge.

SYSTEM CHARGE

Q. What is the "System Charge"?

A. Columbia Gas of Pennsylvania, Inc. ("Columbia" or "Company") is proposing to change the fixed monthly charge that is currently referred to as "Customer Charge" on customer bills and in Columbia's Tariff Gas PA. P.U.C. No. 9 to "System Charge".

Q. What is the reason for the labeling change to the fixed monthly charge?

A. The reason is purely a visual and perception change. Utilities do not charge

customers for being customers, i.e. "Customer Charge". They charge customers to recover costs incurred to provide distribution services that include meter reading, billing and customer service. From Columbia's perspective the term "Customer Charge" is misleading and does not adequately inform customers of the purpose of this monthly charge.

Q. On page 51, lines 21 and 22 through page 52, line 1, Mr. Hubert states "The Company believes the term 'system charge' more accurately reflects what the fixed charge represents because the monthly charge should recover the monthly customer costs as well as costs to maintain the entire system". What is your response to that statement?

A. Mr. Hubert's statement is accurate, the Company does believe that the term 'system charge' more accurately reflects what the fixed charge represents. In its Consumer's Dictionary for Natural Gas Competition[1] the Pennyslvania Public Utility Commission ("Commission") defines Customer Charge as "A monthly charge to cover NGDC costs such as maintaining the gas lines, meter reading and billing." Therefore, not only *should* the monthly charge recover costs to maintain the system, according to the Commission's definition, the monthly charge *does* recover maintenance costs. "System Charge" is a better label, because it does not imply that it is limited to the recovery of customer costs.

Q. Is Columbia's proposed labeling change of the Customer Charge associated with any of the Rate Designs proposed in this Rate Case?

A. No, it is not. I&E witness Hubert makes a statement in his testimony on page 52,

[1] Consumer Dictionary for Natural Gas Competition, Glossary of Gas Terms available by clicking the word "Glossary" at http://www.puc.state.pa.us/consumer_info/natural_gas/natural_gas_shopping/gas_shopping_tool.aspx

lines 10 through 12 that Columbia uses the term to enhance its argument to convert the monthly and usage charge rate structure to a rate structure that only includes a monthly charge. However, even if Columbia had not proposed a monetary change to the fixed monthly charge, the recommendation to rename the "Customer Charge" a "System Charge" would have been included in my testimony. The "System Charge" terminology was conceived independent of any rate design proposal.

Q. OCA witness Watkins states in his testimony on page 30, lines 3 and 4, that he is not aware of any utility in Pennsylvania that uses a term other than "Customer Charge" as it relates to Residential fixed monthly charges. Do you agree?

A. Columbia has not researched the format and nomenclature other Pennsylvania utilities use on their bill.

Q. Mr. Watkins also states that because the phrase "Customer Charge" is used in regulations and Commission customer education materials the Commission should not allow Columbia to use the phrase "System Charge". Do you agree with that statement?

A. Columbia agrees there are references to "Customer Charge" in regulations and in customer education materials developed for the regulated electricity industry. Columbia also wishes to point out that "basic charge" is also referenced in regulations as an "or" to Customer Charge in Section 62.74, which indicates "Customer Charge" is not an exclusive phrase. Columbia is not aware of customer education materials developed by the Commission for the regulated gas industry other than the PAGasSwitch page on the Commission's website.

Q. Do you have any other rebuttal statement to Mr. Watkins' opposition to the "System Charge" label?

A. Yes. Changes that enhance accuracy and customer understanding are worthy of serious consideration and should not be rejected because they are new or different. Consistent with the Commission's preference that utilities employ plain language that avoids the use of utility terms not commonly understood (Section 69.251), Columbia has suggested the use of "System Charge" in lieu of the inaccurate and misleading phrase "Customer Charge". The phrase "System Charge" is a more accurate label for the monthly fixed charge on customer bills because it encompasses more than just customer costs and, as such, it would better inform Columbia's customers about the costs that are recovered in the monthly charge.

Q. What does OSBA witness Knecht's testimony on page 54, line 4 include about the change to the bill format?

A. Mr. Knecht correctly recognizes Columbia's desire to simplify the customer bill.

USAGE CHARGE

Q. On page 52, lines 9 and 10 of OSBA witness Knecht's testimony, he offers a definition of "Commodity Charge" as "a per-Dth charge for all customers related to distribution costs which Columbia proposes to rename "Usage Charge." Is this an accurate statement?

A. The term "Commodity Charge" is defined in Columbia's tariff on page 24 as "basic service charges for natural gas supply services to retail customers, excluding charges for natural gas distribution service." The term Commodity

Charge is incorrectly used in Columbia's tariff on page 16, 17 and 20 because other charges, including the distribution charge are listed under "Commodity Charge". Columbia is proposing to use the term "Usage Charge" on pages 16 through 20 of its tariff to correct the inappropriate use of the term "Commodity Charge".

PRICE-TO-COMPARE

Q. At Page 54, line 7, Mr. Knecht states that customers will not be able to figure out how the Price-to-Compare is derived if the bill line items proposed by Columbia are implemented. Does Columbia have a response to Mr. Knecht's statement?

A. Yes. Columbia understands and agrees with Mr. Knecht's point regarding a customer's difficulty in determining how the Price-to-Compare is calculated. That is specifically why Columbia created Tariff Page No. 21c which is reflected in Exhibit No. 14, Schedule 2, Attachment 2, Page 26 of 108. This new tariff page details the components of the Price-to-Compare. Additionally, since Columbia plans to reflect the Price-to-Compare in a bill message each month, the need for the customer to calculate the Price-to-Compare will be eliminated.

Q. Mr. Knecht identifies another purported disadvantage of Columbia's Price-to-Compare. Please describe Mr. Knecht's second disadvantage.

A. The second disadvantage, as listed on page 54, lines 10-12 of Mr. Knecht's testimony is that the Price-to-Compare for SGSS customers is only comparable to Choice service under Rate SCD and not to transportation service under Rate SGDS. SGSS customers have the option of either service.

Q. What is your response to this "disadvantage"?

A. Mr. Knecht is pointing out a fact that currently exists. The Price-to-Compare for SGSS customers today is only comparable to Choice service for Rate SCD. While the changes proposed by Columbia do not make the existing problem worse for SGSS customers considering rate SGDS, they are a step in the right direction for RSS and SGSS customers who are considering participation in the Choice program by providing those customers multiple resources for obtaining the current PTC.

Q. Does Columbia endeavor to advise SGSS customers of their options under both SCD and SGDS?

A. If an SGSS customer contacts Columbia and asks about the difference in rates between Rate SCD and Rate SGDS those differences are explained.

PASS-THROUGH CHARGE

Q. On page 54, lines 13 and 14, Mr. Knecht states that the Pass-through Charge will change for a customer who shifts from sales to Choice service. Do you agree with this statement?

A. Columbia agrees that the Pass-through Charge will change for customers shifting from sales service to Choice service. The reason for that change is that Choice customers receive the Capacity Assignment Factor rate component and sales service customers do not. Columbia is forthright in its presentation of the Pass-through Charge as broken down in its publicly available proposed Tariff Page No. 21b, reflected in Exhibit No. 14, Schedule 2, Attachment 2, Page 25 of 108.

Q. Mr. Knecht offers his own suggestion for line items on the bill and the components that make up those line items. What does he suggest?

A. Mr. Knecht proposes that Columbia bill the Natural Gas Suppliers ("NGSs") for the PGDC, PGDC E-factor, Capacity Assignment Factor credit, the Tennessee credit and any cash working capital charge related to gas in storage. The Gas Supply Charge for Sales Service customers would then include the PGDC and the Gas Cost Adjustment would include the PGDC E-factor. The Price-to-Compare would be the sum of the Gas Cost Adjustment and the Gas Supply Charge. Mr. Knecht states this will result in the same Price-to-Compare for SGSS customers considering Choice on rate SCD as well as SGSS customers considering Gas Distribution Service on SGDS.

Q. What are Columbia's thoughts on Mr. Knecht's bill format suggestion?

A. Columbia appreciates the bill format suggested for future study by Mr. Knecht and Columbia will consider the proposal for a future filing with the understanding that in order for his proposal to be implemented the Commission will have to give Columbia permission to bill the load balancing charges, including the PGDC, the PGDC E-Factor, and the Capacity Assignment Factor, to the NGSs as described in Mr. Knecht's testimony.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 117-R

2-13-13
Hbg SR

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

THOMAS C. HECKATHORN

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. Thomas C. Heckathorn, 200 Civic Center Drive, Columbus, Ohio 43215.

Q. Are you the same Thomas C. Heckathorn who previously submitted direct testimony in Docket No. R-2012-2321748?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of this rebuttal testimony is to respond to the Direct Testimony of Mr. James L. Crist, filed on behalf of the Natural Gas Suppliers ("Suppliers" or "NGS").

Q. What issues will you be addressing in this rebuttal testimony?

A. I will address the following issues set forth by Mr. Crist in his Direct Testimony: a) the Company's penalties for over/under delivery of gas supplies delivered by, or on behalf of General Distribution Service ("GDS") customers; b) the Company's penalties for over/under delivery of gas supplies on behalf of Choice customers; c) the Company's administrative procedures, including blackout dates ("freeze period") and the fees charged to correct errors/late submission; d) the Company's agreement to provide Eligible Customer Lists with account information; and e) describe the GasSource and GP1 systems and how they are a benefit for all parties.

PENALTY FOR OVER/UNDER DELIVERY BY GDS CUSTOMERS/NGS

Q. At the bottom of page 5 of his Direct Testimony Mr. Crist discusses the Company's monthly cash out/in and penalty for over/under delivery of gas for or on behalf of GDS customers. Do you care to comment on his testimony?

A. Yes, I do. Initially, it is relevant to note that Columbia provides GDS customers with the option to bank gas supplies for subsequent use under Rider EBS – Elective Balancing Services. The cash out/in tolerance levels identified by Mr. Crist on a supplier's monthly delivered quantities refers to situations when a GDS customer's bank, or as is the predominate case, the bank managed by an NGS for its aggregated GDS customers, is either depleted, in which case Columbia is selling gas to serve the customer, or it exceeds the bank tolerance level, which is the maximum amount of banked gas the customer/NGS can maintain in any month. By electing Option 1 EBS, the customer or its proxy have the opportunity to: (1) maintain a bank from month to month on Columbia's system; (2) access banked gas on a firm basis during periods when there are operational limitations on the system; and (3) to add bank on any day to Columbia's system. For larger GDS customers that have selected Option 1 (Full Balancing Service) under Columbia's tariffed Elective Balancing Services ("EBS)", the customer's bank tolerance level is equal to 5% of their current annual quantity. For smaller GDS customers that have selected Option 1 under EBS, their bank tolerance level is equal to 10% of their current annual quantity November through September and 5% of their current annual quantity for the month of October. For example, a supplier serving a customer using 1,200,000 therms per year (or an average of 100,000 therms per month) can have a bank of up to 60,000 therms at any time. Moreover, a supplier can aggregate multiple customers into a single group for banking purposes, providing even more flexibility to stay within tolerance. The Company's bank provides the

customer, or its NGS, with a significant tolerance and Mr. Crist's suggestion that somehow these cash out/in costs are punitive is inappropriate. The bank tolerance levels provide NGSs more than adequate room to manage their supply on a monthly basis. Falling outside of those bank tolerance levels, or using more gas in a month than the sum of deliveries and banked gas, which are the reasons why the cash out/in occurs, is not the result of an inadvertent mistake or restriction on delivery rules, but is most likely the result of an NGS attempting to game the system by purchasing/selling supplies from/to the Company at favorable prices relative to the market or is a demonstration that the NGS is simply not managing its business.

Q. Would you like to clarify an issue raised by Mr. Crist in his testimony regarding over/under deliveries?

A. Yes. The cash out/in referred to by Mr. Crist at the bottom of page 5 of his Direct Testimony relates to monthly transactions and does not relate to penalties associated with an NGS' failure to comply with an Operational Flow Order ("OFO") or Operational Matching Order ("OMO").

Q. What are OFOs and OMOs?

A. OFOs and OMOs are notices issued by the Company that instruct GDS customers and/or their Suppliers to reduce or increase the amount of gas delivered on their behalf. An OFO and an OMO are essentially the same order with the primary difference being that OFOs apply to customers with monthly measured meters and OMOs apply to customers with daily measured meters. These notices may be issued when too much supply has been nominated for delivery to the Company, wherein

the Company seeks a reduction in the nominated quantities as the combination of market demand and storage injection rights are insufficient to receive all the gas nominated; or they may be issued when inadequate supply is available to the Company to meet the demand of its customers and the Company seeks GDS customers and/or their Suppliers to increase supply to match a percentage or all of the GDS customers' demand (net allowed deliveries of banked gas supplies), such as extremely cold days when supplies are needed to serve residential customers and are not available to offset deficient deliveries for GDS customers. OFOs and OMOs are issued when the system is under duress from too much or too little gas. NGSs, as the Supplier for GDS customers, have an obligation to assist the Company in such circumstances by not aggravating system operating conditions through delivering excess or insufficient supply as the case may be. In effect, and very importantly, OFOs and OMOs are critical to protecting gas supplies, and gas supply costs, of all customers, and in particular critical needs customers.

Q. Is there a penalty for violating an OFO/OMO Order?

A. Yes, the Company charges a penalty of $2.33 per therm plus a pro rata portion of any costs or charges incurred by Columbia on the day of the violation.

Q. On page 6, starting at line 5, Mr. Crist states "At Columbia of Virginia the penalty is only $10/mcf. At Columbia Gas of Ohio the penalty is only $10/mcf". Is this statement correct?

A. No. As reflected on original sheet 429 section 10.6 of Columbia Gas of Virginia's Tariff, Columbia Gas of Virginia, during a balancing service restriction ("BSR"),

charges the customer or its supplier, in the case of under delivery, at a price of 150% of the midpoint Transco, zone 6, non-N.Y. city gate price as published in *Gas Daily* for that day and further charges the customer or its supplier for any penalties charged to Columbia Gas of Virginia. For over delivery during a balancing service restriction, Columbia Gas of Virginia will purchase such over deliveries at 50% of the midpoint Transco, zone 6, non-N.Y. city gate price as published in *Gas Daily* for that day plus charge any penalties incurred by Columbia Gas of Virginia. As reflected on sheet 66 sections 24 and 25 of Columbia Gas of Ohio's Tariff, failure to comply with an OFO/OMO will result in an assessment of a charge equal to the higher of:

a) Ten (10) dollars times the OFO/OMO shortfall or overage; or

b) 110% of the TCO Daily Index adjusted for the SST commodity and shrinkage times the OFO/OMO shortfall or overage; or

c) The payment of the pro-rata share of all other charges, including gas costs, penalty charges or cash-outs, incurred by the Company as a result of non-compliance on the date of the OFO/OMO shortfall or overage.

Q. Mr. Crist attempts to compare the penalty structures at other distribution companies to Columbia Gas of Pennsylvania. Is this an appropriate comparison?

A. Definitely not. First, Mr. Crist has not reflected the correct penalty provisions in the other jurisdictions. Second, distribution companies in other jurisdictions can have quite different rate structures, operational requirements, transportation programs

and banking and balancing tolerances. It is not at all appropriate to attempt to make such comparisons.

Q. On page 5 of his Direct Testimony, beginning at line 17, Mr. Crist states that "the Supplier is cashed in/out as the case may be, and the Company adjusts the gas price by up to 30% in that case, which is itself a very large penalty for the NGS to bear." Do you have any comments on this statement of Mr. Crist?

A. Yes. Mr. Crist misrepresents the applicable tariff-rules to cash out/in transactions. As I previously noted, the cash out/in is the result of a Supplier failing to properly manage its generous monthly bank (5 or 10% of current annual quantity) provided by the Company and is not a penalty. These adjustments to the Index Price apply only to quantities where the GDS customer/Supplier has exceeded their bank level or when they have depleted their bank and call upon supplies purchased by Columbia for its PGC customers to supplement their deliveries. The Company's cash out/in mechanism provides a tiered cash out/in process where small cash out/in quantities are sold/purchased at levels as low as a 5% adjustment to the Index Price, increasing stepwise to where large cash out/in quantities are sold/purchased at a 30% adjustment to the Index Price. These adjustments to the Index Price are not daily penalties. The cash out/in relates solely to banks that can be built up or reduced over a period of time, long or short, as determined by the Supplier. In short, the cash out/in adjustment is a charge for the Suppliers' use of system supply as an alternative to managing its bank within the generous parameters provided by the Company. In no way is the cash out/in adjustment a

penalty. Mr. Crist's misrepresentation of the cash out/in of an activity applied monthly on the Company's generous bank tolerances, an activity that is applied to a process easily under the Supplier's control and then calling this "a very large penalty" is a gross misrepresentation of the purpose of the commonly used cash out/in tiered process approved by the Commission. Mr. Crist compounds his mischaracterization by linking the cash out/in adjustment to the OFO/OMO penalties at page 5 of his testimony.

Q. Is the cash out/in charge cumulative to an OFO/OMO penalty?

A. The two items are separate, as I previously noted. The OFO/OMO penalty is determined on days when OFOs/OMOs are issued. Cash out/in charges are not assessed on a daily basis, but instead are based upon failure to comply with monthly bank tolerances. Thus a customer/supplier could be assessed a penalty for failing to comply with an OFO/OMO order on any single day, but be within bank tolerances for the month. Conversely, a customer/supplier could be subject to a monthly cash out/in charge, but not be penalized for an OFO/OMO violation because they were in full compliance with the OFO/OMO order.

Q. Beyond the generous bank levels provided by the Company to GDS customers and their Suppliers, are other options available to Suppliers to avoid a bank cash out/in?

A. Yes. The Company provides Imbalance Trading Services, which include Bank Balance Transfers and Gas Transfer Service. These are services that were developed at the specific request of the Suppliers. These services allow customers that have selected EBS Option 1, or their Supplier, to transfer gas in accordance with the

Company's tariff. These services provide customers, or their suppliers, the opportunity to reduce or eliminate cash out/in charges.

Q. Is there a means by which a customer or Supplier can avoid OFO/OMO penalties?

A. Yes. Customers that have selected EBS Option 1, or their Supplier, can utilize Gas Transfer Service to reduce or eliminate OFO/OMO penalties. This allows suppliers, who have selected EBS option 1, to transfer between their banks to comply with an OFO/OMO order. Thus, if a supplier is unable to make deliveries to comply with an order, they can trade with another supplier to make up their difference.

Q. On page 6, lines 22-23, Mr. Crist states that Suppliers "will also have to pay one month's demand charge and any other costs that are incurred". Do you have any comments on this statement?

A. Yes. In this answer, Mr. Crist again mixes two separate activities in an attempt to develop a scenario that does not exist. First, Mr. Crist is incorrect when he states that the Company would require Suppliers to pay one month's demand charge. The Company's tariff provides no such requirement. Next, Mr. Crist is correct that a Supplier may be subject to additional costs, but only on days when the Company has issued an OFO/OMO. Should a Supplier's failure to abide by the requirements of an OFO/OMO cause the Company to incur additional costs, such as additional commodity costs, upstream pipeline penalties, etc., those additional costs will be passed on to the Supplier directly in proportion to the level that the Supplier's failure caused the Company to incur the additional costs.

Q. On page 6 of his Direct Testimony, Mr. Crist claims that paying a simple premium

for gas supplied by the Company is more than enough of an incentive for a Supplier to make a good faith effort to deliver the gas properly to the system on OFO/OMO days. Do you agree with Mr. Crist?

A. No, I do not. First, as explained previously, the Company does not impose a premium for gas supplied by the Company on a peak day. The cash out/in is computed monthly. A customer/supplier can violate an OFO/OMO Order yet be in compliance with monthly bank tolerance and not incur any cash out/in. Second, on OFO/OMO days, we are talking about situations when the system is under duress. It is not the Company's obligation to step into the shoes of a Supplier to provide supplies for GDS customers that have made the conscious decision to have their supply deliveries made by a Supplier instead of the Company. A good faith effort is not enough because, as I stated earlier, Suppliers have an obligation to assist Columbia during these periods of duress. When an OFO/OMO is issued, the responsibility of the Supplier is to make sure that adequate supplies are delivered to the Company to satisfy their customers' requirements given the fact the Company's supply/capacity portfolio and management of such portfolio does not contemplate the use of Company supplies to serve Suppliers' GDS customers. Next, Mr. Crist's assertion that a Supplier can "buy gas as cheaply as Columbia if it tried" is not a reason to reduce the penalty for the Supplier's failure to deliver supplies in accordance with the OFO/OMO for not "trying". Finally, prior to the Company issuing an OFO/OMO, the Company makes every effort to provide GDS customers and Suppliers with an Operational Alert that informs the GDS customers and their

Suppliers of pending conditions that may require the Company to issue an OFO/OMO. Generally, if GDS customers and their Suppliers respond to the Company's Operational Alerts with sufficient supply changes as requested by the Company, then the Company may be able to forego issuance of the OFO/OMO and penalties for failure to abide by the OFO/OMO are averted.

Q. On page 7 beginning on line 6 of his Direct Testimony, Mr. Crist states that "penalties exist to address and prevent improper behavior". Do you agree with Mr. Crist?

A. Yes, I agree wholeheartedly. However, as I noted previously, the Company's existing EBS provides GDS customers or their Suppliers with a generous tolerance level in which to manage their supply. In addition, Columbia has developed additional mechanisms to assist GDS customers and their Suppliers to manage their supply, ie Bank Balance Transfers and Gas Transfer Service. Finally, as I noted above, the cash out/in occurs on a monthly basis not daily. GDS customers and their Suppliers have ample opportunity to avoid any penalties. The OFO/OMO penalties are designed to prevent improper behavior on days of system stress.

Q. Continuing on with Mr. Crist's answer initiated on Page 7, Line 6, do you have any additional comments?

A. Yes. First, Mr. Crist claims that penalties should have "a reasonable cost basis". This comment is misplaced and counter to Mr. Crist's own comment that penalties exist to address and prevent improper behavior. If penalties are only to be cost based and if, as Mr. Crist states in his Direct Testimony, Suppliers can purchase

supplies as cheaply as a natural gas distribution company if they tried, then this statement does nothing but shift costs and risks to natural gas distribution companies and their PGC customers. Penalties are not cost based for the very reason that they must be reasonably punitive as a means to deter and to address improper behavior, i.e. for Suppliers to abide by the requirements of an OFO/OMO, not to determine after the fact what costs were incurred as a result of the Supplier's failure. Suppliers have the necessary tools to avoid penalties and potential additional costs, and should not have even the slightest reason to consider ignoring an OFO/OMO order to take advantage of arbitrage opportunities at the expense of the Company and its PGC customers.

Next, Mr. Crist attempts to excuse a Supplier's failure to comply with an OFO/OMO Order because it makes a "delivery mistake". This concept is baseless for several reasons. Initially, from a practical standpoint it is impossible to demonstrate that a "delivery mistake" occurred. The same activities that result in a "delivery mistake" are the same activities that occur when a Supplier intentionally redirects supplies from one market or customer to another to profit through arbitrage. Second, a Supplier has several opportunities to correct a "delivery mistake" and thereby comply with an OFO/OMO. For example, if a supplier schedules a delivery quantity different from the quantity directed by an OFO, such quantity can be adjusted through an intra-day nomination by the Supplier or through the Company's Gas Transfer Service. Third, Suppliers are quite aware of the importance of complying with an OFO/OMO, and should not minimize non-compliance by asserting a

"mistake" was made.

Finally, Mr. Crist claims that "If no harm to the system results from an imbalance, then the NGSs should not be penalized above and beyond the cash out charges that are incurred." Here again, Mr. Crist is misrepresenting the differences between monthly cash out/in of a bank and penalties resulting from failure to abide by an OFO/OMO. As explained previously, a Supplier can violate an OFO/OMO, yet not be subject to a monthly cash out/in. This statement also contradicts his previous comment that penalties exist to prevent improper behavior. Additionally, and more importantly, the concept of "no harm" is false. To the extent that a Supplier fails to abide by the requirements of an OFO/OMO, someone else must make up for that Supplier's failure. Other Suppliers that abided by the OFO/OMO are harmed to the extent that they do not take advantage of the economic opportunity that the failing Supplier pursued in lieu of abiding by the OFO/OMO. If allowed to be implemented, the concept of "no harm, no foul" provides an incentive for Suppliers to seek economic opportunities outside of delivering required supplies to the Company, which could have catastrophic implications for the Company and its customers. Mr. Crist's unsupported claim that in the absence of a "no harm, no foul" system the whole purpose of imposing penalties will be undermined is completely false, lacks reasoning, is counter to his acknowledgement that penalties exist to prevent improper behavior, and is not supported by the Company's experience. In fact, imposition of a "no harm, no foul" system would undermine system integrity and place at risk PGC customers, a result that Columbia's current

penalty structure is designed to prevent. An example of how fundamentally flawed such logic is – it would be akin to requiring a waiver of all fines/charges associated with a speeding ticket for the driver of a vehicle, unless such speeding incident resulted in an accident or death.

Q. On page 7 of his Direct Testimony, Mr. Crist recommends that the OFO/OMO penalty be dropped altogether or reduced to $10/Mcf; do you agree that such a reduction would be a reasonable step?

A. No. The Suppliers have raised this issue several times in the past including the Company's 2010 base rate case. Through settlement in that case, Columbia reduced the OFO/OMO penalties from $30 to $25/Mcf. This was later modified to $2.33 per therm. Mr. Crist has provided no good cause or factual information to support a further reduction. Moreover, because of Mr. Crist's misunderstanding or misrepresentation of cash out/in charges, elimination of the $2.33/therm penalty would greatly reduce Columbia's ability to manage its system.

Q. On page 8 of his Direct Testimony, Mr. Crist discusses the penalty for Choice underdelivery, and maintains that there are two major disadvantages to the penalty for Choice Suppliers. Do you care to comment on Mr. Crist's statement?

A. Yes. Mr. Crist claims the penalty is too high and not cost based. As I have explained earlier, the concept of a penalty being cost based is baseless and without merit. The Company's Choice Program provides its highest priority, residential and small commercial customers consuming 64,380 therms or less per year, the opportunity to select a supplier other than the Company to provide their natural gas

commodity requirements. All other services such as distribution, metering, billing, etc., continue to be provided by the Company. Once a customer has contracted with a Choice Supplier for its natural gas commodity service, that Supplier provides the Company with required information about the customer and the customer participation in the Choice Program is verified by the Company. Prior to the beginning of each month, the Company determines the normalized annual demand of each Supplier's customer group and determines the Supplier's daily delivery requirement for the subsequent month by dividing that total normalized annual demand by 365. The product of this calculation ($1/365^{th}$ of the normalized annual demand) is the quantity that the Supplier is required to deliver under the Choice Program each day of the subsequent month. This process is repeated each month. Once the Company determines the Supplier's delivery obligation, it makes an assignment of firm transportation service ("FTS") capacity, as necessary, to each Choice Supplier equal to the delivery requirements of the Choice Supplier. This assignment of FTS capacity is then used by the Choice Suppliers to deliver the identified supplies to the Company on a constant daily basis each day of the month. This constant delivery requirement each day of the year is why Columbia's Choice Program is referred to as an "Average Day Program." Through development and implementation of the Company's Choice Program, the Company has greatly simplified the Supplier's delivery obligation under the Choice Program design.

Unlike GDS customers, these high priority residential and small commercial customers do not have the same opportunities to reduce usage or change to an

alternate fuel as do larger commercial and industrial customers. Thus, a Choice Supplier's failure to deliver has a greater implication upon the Choice customers and thus a higher penalty is warranted. Furthermore, unlike GDS Suppliers, the assignment of FTS capacity eliminates the risk that Suppliers must find appropriate capacity to service Choice customers. The simple delivery obligation required of the Choice Suppliers, one that stays constant for the month, reduces the Choice Supplier's risks by allowing them to make a single supply nomination for the same quantity each day of a given month. The Choice Program has been designed such that it is easily manageable for Choice Suppliers to serve these firm requirements customers and a failure to deliver deserves a more severe penalty because of the differing nature of Choice customers relative to GDS customers. Because the design of the Choice Program is dependent upon the delivery each day, it is appropriate that a penalty be applicable each day that a delivery failure occurs. Mr. Crist's entire testimony in this section is directed at reducing Suppliers' exposure to penalties for improper behavior, behavior that is directed solely to benefit the Suppliers economically.

Q. On page 8, of his Direct Testimony, Mr. Crist proposes a penalty structure equal to 150% of the TCO daily index price along with any other cost incurred by the Company that day due to the supplier shortfall, in lieu of the existing penalty structure. Do you have any comments regarding Mr. Crist's proposal?

A. Yes. Initially, I note there are two separate penalties related to the Choice Program. The first, a daily penalty of $2.33 per therm is in place to ensure delivery

consistency by Choice Suppliers in accordance with the structure of the program, while the second, a daily penalty of $4.66 per therm applies to those days when the Company has issued an OFO/OMO and compliance with the delivery requirements of the Choice Program are even more critical. Mr. Crist's suggestion to replace these separate penalties with a single, substantially reduced penalty is inappropriate for several reasons. First, Mr. Crist's proposal addresses only one potential situation when an OFO/OMO may be required and ignores those instances when an OFO/OMO is needed to address too much gas being nominated to the system. Next, the Choice Program has been specifically designed with the expectation of even daily deliveries by Choice Suppliers. Consequently, the Company must plan its purchase activity for its PGC customers by taking into consideration these expected deliveries by Choice Suppliers. Allowing Choice Suppliers to deviate from this delivery requirement places additional uncertainty on the Company's purchasing plans. Uncertainty generally increases the costs of such purchases to the detriment of PGC customers. For example, the Company could be forced to increase planned gas purchases if Choice Suppliers underdeliver, to avoid penalties for exceeding daily storage withdrawal limitations. Mr. Crist desires to eliminate penalties for failure to deliver on all days, ignoring the program's fundamental design and premises of the Suppliers' obligations under the Choice Program. This desire becomes an even greater concern on days when an OFO/OMO has been issued, because failure to comply could imperil service to human needs customers. Furthermore, according to Mr. Crist's own testimony, a penalty should act to

prevent improper behavior. Under this concept, the higher the penalty the greater the deterrent, yet Mr. Crist's suggestion here is in opposition to his own testimony on this point. Lastly, implementation of Mr. Crist's recommendation would provide Suppliers with the opportunity and incentive to take advantage of pricing arbitrage in lieu of fulfilling their delivery obligation, to the sole economic benefit of Mr. Crist's clients. Arbitrage opportunities act to serve only the economic benefits of the Suppliers at the direct expense of the Company and its PGC customers. Mr. Crist's arbitrage logic is even more flawed for Choice customers than it is for GDS customers.

Q. Do you consider the penalties and cash in/out charges a barrier to entry into the various programs or a cause for restricting suppliers from participating in the programs?

A. There are over 20 suppliers currently providing service to GDS customers on the Company's distribution system and over 20 suppliers participating in the Company's Choice program. The penalties and cash in/out charges can hardly be considered as being a hindrance to these programs.

ADMINISTRATIVE PROCEDURES REGARDING TRANSPORTATION SERVICE

Q. At the bottom of page 9 of his Direct Testimony, Mr. Crist states the black-out dates, known on Columbia's system as the "freeze period", is undesirable. Do you have any comments?

A. Yes. The "black-out dates" known on Columbia's system as the "freeze period" for

enrollments of customers into Choice service by alternative natural gas suppliers is necessary for 1) the compilation of new enrollment data and existing customer data for daily delivery requirements processing; 2) the creation of daily delivery requirements; 3) posting of the daily delivery requirements; and 4) capacity assignment. Modifying this process would require a complete redesign of the Choice program, including significant modifications to the Company's processes and systems.

Q. Please describe the enrollment process.

A. Exhibit TCH-1R to my testimony provides a very simplified view of the enrollment process. Enrollments that are received by the 15th of the month are processed and the new Choice Supplier commodity rate will be reflected on the customer's bill in the next month's billing cycle. In this example, the enrollment occurs on August 15. The customer information for that Choice Supplier is then aggregated and the delivery requirements for September are determined and provided to the Choice Supplier. Interstate pipeline firm transportation capacity is also released to the Choice Supplier beginning September 1 in accordance with the new requirement under the demand curve. The billing cycle for September commences August 31st in this example and ends September 30th. The customer's bill issued during the September billing cycle will reflect the new Choice Supplier commodity rate. If for example, the customer is billed on August 31st, the new Choice Supplier commodity rate will be reflected on the bill, the usage reflected on the bill will be from July 29th through August 31st and the new Choice Supplier will begin delivering gas for this

customer on September 1st.

Q. On page 11 of his Direct Testimony, Mr. Crist states that "Peoples was able to change their system for the good of the customer and now if a customer enrolls he will start on the next read date with the supplier regardless when he enroll". Please provide a more detailed enrollment example and compare that example to Peoples Natural Gas.

A. Exhibits TCH-2R and TCH-3R to my testimony provide more detailed examples reflecting enrollments received by Columbia prior to the 15th of the month and enrollments received after the freeze period, respectively, and compare those to Peoples Natural Gas. In the example reflected in TCH-2R, Columbia receives an enrollment on August 15th and the customer is billed on August 31st, which is included in the September bill cycle. The new Choice Supplier's commodity rate will then be reflected on the August 31st customer bill for usage from July 29th through August 31st.

Pursuant to a review of Peoples Natural Gas' "Transportation Programs Data Exchange File Specifications" revised January 23, 2013 (http://www.peoples-gas.com/UserContent/UserFiles/PNG%20Enrollment-Billing%20File%20Specs%20REV%201_23_13.pdf), Columbia has determined that, under this same example with a meter read date that occurs after the rescission period, the customer's bill would not reflect the new Choice Supplier commodity rate until the September 30th bill, a month later than Columbia.

In the example reflected in Exhibit TCH-3R, should the customer be enrolled after

the freeze period on August 22nd, and the customer bills on September 22nd, the customer will be billed by Columbia under the old commodity rate for the September 22nd bill for the September billing cycle and will be billed under the new Choice Supplier commodity rate on October 21st, the October billing cycle. With Peoples Natural Gas, for enrollments received during the rescission period, the same results would occur with the customer not being billed the new Choice Supplier commodity rate until October 21st.

In either case, the customer would realize the new Choice Supplier commodity rate on Columbia's bill no later than and possibly sooner than it would on Peoples Natural Gas.

Mr. Crist's insistence that the freeze period is undesirable appears to have no merit when it comes to the time period required before the new commodity rate is reflected on the customer's bill.

Q. On page 11 of his Direct Testimony, Mr. Crist states that Columbia charges $25.00 per customer for a variety of changes, such as pricing changes, rate adjustments and for customer drops past certain administrative dates. Do you care to comment on Mr. Crist's statements?

A. Yes, the Company has been approached by an NGS asking for assistance with late rate submission and/or customer drops past the administrative window that were missed as a result of administrative errors on behalf of the NGS. In efforts to assist the NGS and in the spirit of good customer service to ensure that customers are billed correctly the first time, the Company has assisted the NGS and in doing so

have charged fees associated with this type of request. In providing these services to the NGS, customers received a correct bill the first time as opposed to a later corrected bill. The Company believes this is the proper action to take, however, if the NGS disagrees, the Company is willing to discontinue and default to the provisions in section 4.12.3 on sheet 243 of Columbia's Tariff.

Q. The Company held discussions with the NGSs concerning changing some of its processes. What were the results of those discussions?

A. At the request of NGS, the Company agreed to provide for daily processing of customer rate code changes and to provide a date and time stamp confirmation for every file submitted by NGS.

ELIGIBLE CUSTOMER LISTS

Q. Starting at the bottom of page 11 of his Direct Testimony, Mr. Crist discusses Eligible Customer Lists and providing account numbers. Do you care to comment on Mr. Crist's statements?

A. Yes. As the Company has already stated at Docket No. M-2012-2183412, it intends to provide the information upon issuance of a final order and as soon as such programming can be implemented. Considering that the Company currently is providing its customer list free of charge, the purpose of Mr. Crist's testimony in this regard is unclear. This is an issue that should be dealt with in the Commission order and not this proceeding.

GASSOURCE AND GP1

Q. Please describe how the GasSource and GP1 systems are used for gas

procurement and for support of the suppliers' provision of gas supply for their customers?

A. GasSource is a gas management system utilized by Northern Indiana Public Service Company, Columbia Gas of Massachusetts, Columbia Gas of Kentucky, Inc., Columbia Gas of Maryland, Inc., Columbia Gas of Ohio, Inc., Columbia Gas of Pennsylvania, Inc., and Columbia Gas of Virginia, Inc. The application focuses on natural gas distribution company gas supply processes including, a) maintenance and administration of pipeline transportation and storage contracts, as well as natural gas supply contracts, including the maintenance of the respective pipeline rates, index rates, and negotiated rates; b) trading activity for both system supply and off system sales including the electronic generation of the respective transaction confirmations; c) scheduling activities for both system supply and off system sales on the various pipelines; d) capacity release activities including those required under the Choice Program; e) maintaining a real-time view of the available capacity on each of the respective pipeline contracts; f) providing a means of reconciling the pipeline invoices, gas supply invoices, and generating off system sales invoices; and g) report generation and electronic feed of information to the accounting system.

Many of these activities such as the administration and maintenance of pipeline contracts and the respective rates, capacity release and invoice reconciliation provide support to natural gas distribution company activity as well as NGS activity. In addition, the items related to off system sales help reduce costs to the

customers through the sharing mechanism.

GP1 is a gas management system designed to post quantities and payments on contracts to purchase Appalachian gas supplies from local gas producers tied directly to Columbia's distribution facilities. It also releases payments to the accounting system. These purchases delivered directly into Columbia's system are used to the benefit of all customers. It is anticipated that the process and functionality of this system will be rolled into GasSource in the near future.

Q. Does this conclude your testimony?

A. Yes, it does.

Exhibit TCH-1 R
Enrollment Process Timeline

Columbia Gas
Choice Reference Manual March 2012

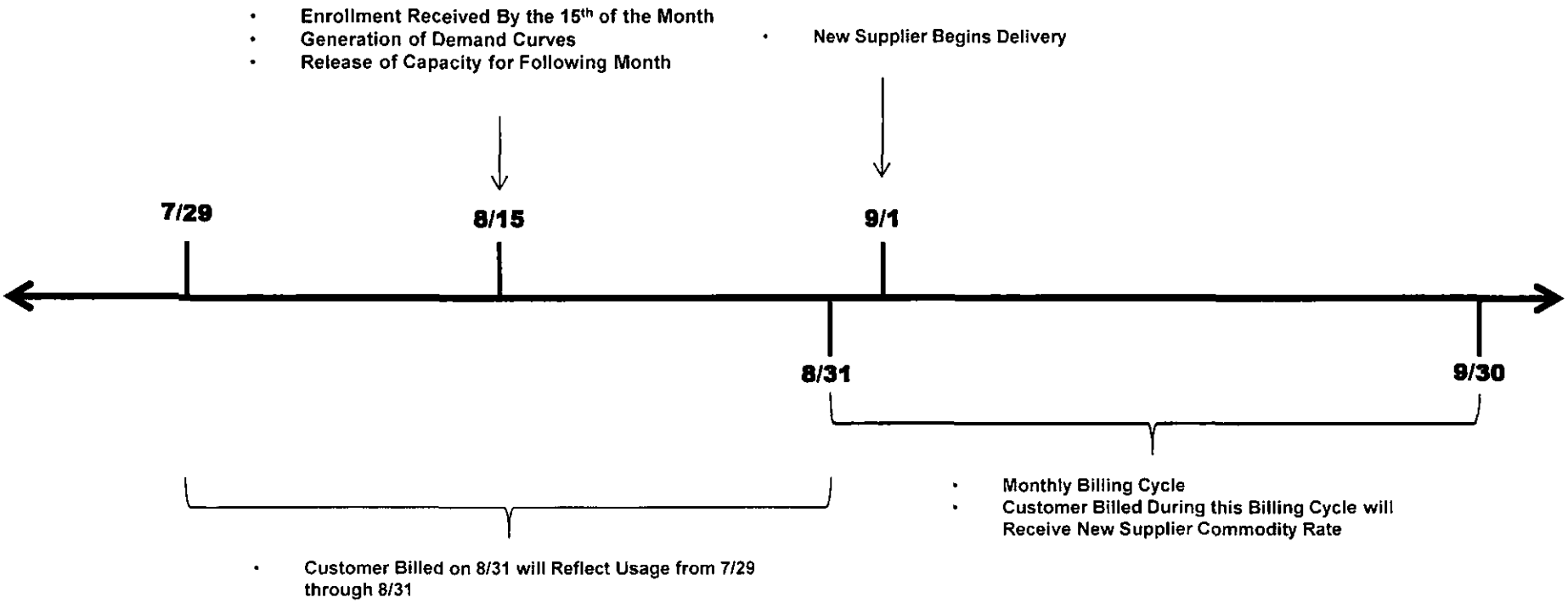
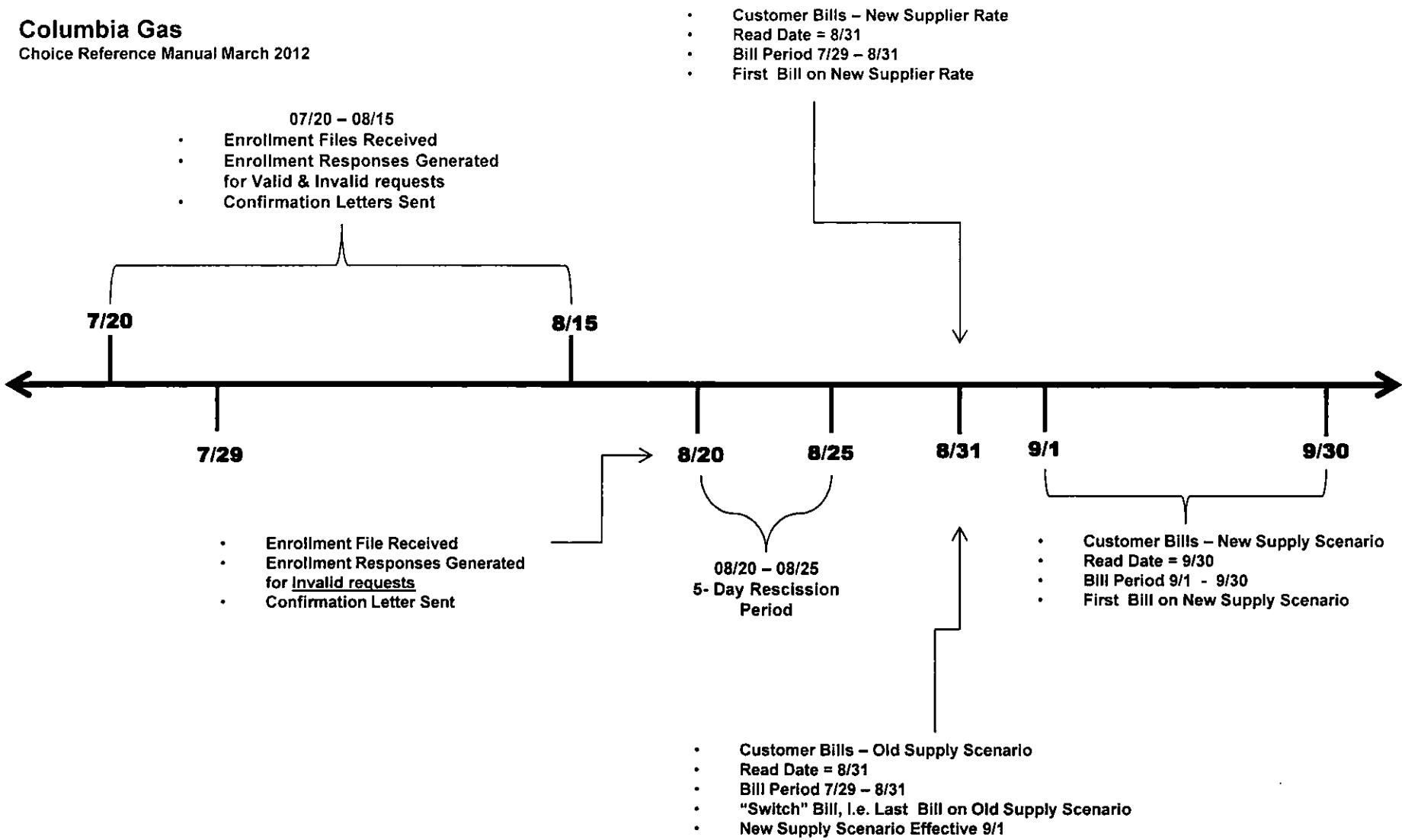


Exhibit TCH-2 R
Enrollment Process Timeline

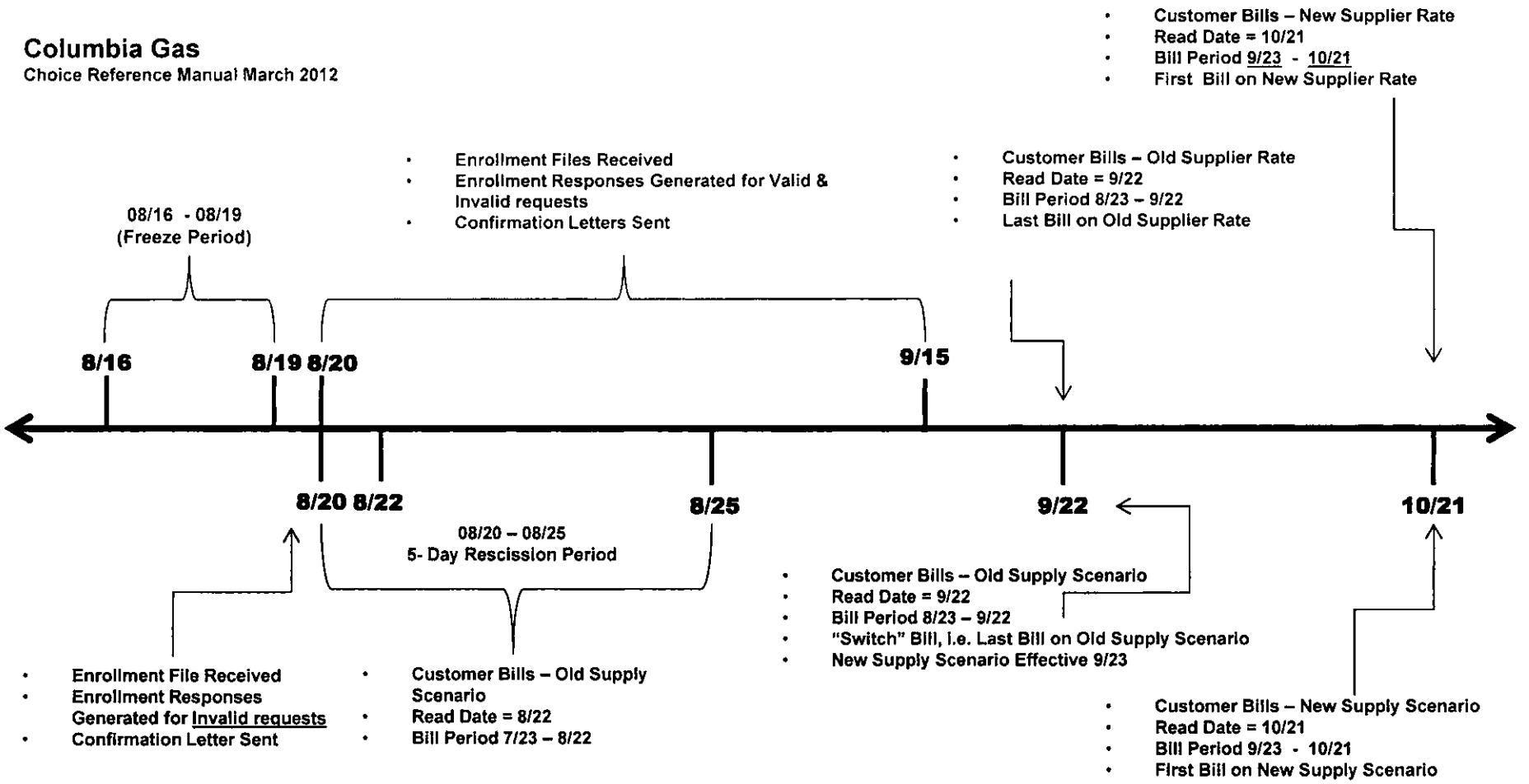
Columbia Gas
Choice Reference Manual March 2012



Peoples
Information taken from Peoples "Transportation Programs Data Exchange File Specifications" Revised 1/23/2013

Exhibit TCH-3 R
Enrollment Process Timeline

Columbia Gas
Choice Reference Manual March 2012



Peoples
Information taken from Peoples "Transportation Programs Data Exchange File Specifications" Revised 1/23/2013

COLUMBIA STATEMENT NO. 117-SR

2-13-13
Hbg 89

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

SURREBUTTAL TESTIMONY OF

THOMAS C. HECKATHORN

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

February 8, 2013

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SECRETARY'S BUREAU

Q. Please state your name and business address.

A. Thomas C. Heckathorn, 200 Civic Center Drive, Columbus, Ohio 43215.

Q. Are you the same Thomas C. Heckathorn who previously submitted direct testimony and rebuttal testimony in Docket No. R-2012-2321748?

A. Yes.

Q. What is the purpose of your surrebuttal testimony?

A. The purpose of this surrebuttal testimony is to respond to the Rebuttal Testimony of Mr. James L. Crist, filed on behalf of the Natural Gas Suppliers ("Suppliers" or "NGS Parties").

Q. What issues will you be addressing in this rebuttal testimony?

A. I will address certain statements made by Mr. Crist in his Rebuttal Testimony related to information technology ("IT") costs.

Q. On page 4 of Mr. Crist's Rebuttal Testimony, Mr. Crist claims that "the Company provided the breakdown of costs, but it was not by system." Would you like to comment?

A. Yes. As Mr. Crist states, the Company provided a breakdown by general categories of IT system functions rather than by IT system. In the Company's response to NGS Set II, data request II-4, the Company stated "not all information technology costs can be associated directly with an information technology system." The Company was unable to identify the costs for many of the individual applications because the costs are not tracked in that manner. However, the Company was able to provide the costs of the two systems directly related to the gas procurement function, those

being GasSource and GP1.

Q. On page 4 of Mr. Crist's Rebuttal Testimony, he states "in the description there were three systems that would clearly be used for system gas procurement, GasSource (#9) and GP1 (#11) and Maximo (#20)." Furthermore, on page 5 of Mr. Crist's Rebuttal Testimony, he states that Maximo "is the supply chain procurement system, which would obviously be used in the gas procurement function." Would you care to comment?

A. Yes. The Company has previously stated that GasSource and GP1 are used in the gas procurement function. Company Witness Strauss in her Rebuttal Testimony recommended 73% of the costs for these systems be allocated to the GPC. With approximately 27% of the Company's customers purchasing their gas supply from NGSs, the 73% represents that portion of our customer base taking sales service. Maximo is used by the Company to purchase office supplies such as binders, pencils, highlighters and paper. It is not utilized in the gas procurement process and the costs therefore should be excluded from the GPC.

Q. On page 5 of Mr. Crist's Rebuttal Testimony, he states "there are aspects of many of the systems that are used in a supportive role in the gas procurement function". He references "systems that deal with financial data (GEAC, Hyperion), billing (GTS, usage history (DIS, NGD data warehouse), and several systems that support employees of the gas procurement function (EASI, PeopleSoft)." Would you care to comment?

A. Yes. Mr. Crist is correct in that there are many different systems the Company

utilizes in its core distribution processes. Attached as Appendix A to my testimony is a listing of the systems identified in the Company's response to NGS Set II, data request II-4. However, the only two systems that are directly utilized in the gas procurement process have already been identified as GasSource and GP1 and the Company has recommended an allocation of 73% of the costs for these systems be allocated to the GPC. The other systems support the core business processes and are not directly associated with the Company's gas procurement process. For example, the Company's retention of data on customer usage history is necessary to the Company's core distribution function, and is not directly associated with procuring gas supplies on an ongoing basis. Usage information is also used to generate demand curves for NGS use when scheduling deliveries. Similarly, the Company bills its customers every month, without regard to whether they are sales or transportation customers. It should be noted that NGSs request billing and usage information on customer lists for prospective customers and receive this information in reports for customers they currently serve. Therefore, the costs of these systems are used for both the Choice NGSs and the Company's gas procurement function and should be excluded from the GPC.

Q. On page 5 of Mr. Crist's Rebuttal Testimony, he states "based on the description of the programs that are clearly used primarily for gas procurement and the other support programs, and considering that after two rounds of data requests the Company still has not provided the specific data I requested, I still have no basis to adjust my allocation of 10% of the total annual IT expenditures". Would you care to

comment?

A. Yes. There is absolutely no basis for the 10% figure suggested by Mr. Crist. The Company has already provided costs for the two systems, GasSource and GP1, which are utilized in the gas procurement process and has recommended that a portion of these costs be included in the GPC. Beyond these two systems, no other IT related costs are appropriate to be included in the GPC because those other costs are not directly related to procurement of gas on behalf of its customers.

Q. Does this conclude your testimony?

A. Yes, it does.

List of Systems Identified in the Company's
Response to NGS Set II Data Request II-4

AutoCAD
Aviator
Call Center VOIP
DIS
EASI
EMDCS
Field Collection System
Field View Software
GasSource
GEAC
GENESYS
GP1
GTS
Hyperion
iCredit
IRTH Ticket Management
IVR/CTI
Learning Management System
Lotus Notes
Maximo
MDT Field Collection
Meter to Cash Data Warehouse
MySource
NGD Data Warehouse
NICE
Panagon Replacement
PeopleSoft HR
PowerPlant
Primivera
RouteSmart
SCADA
Ventyx
Vignette Images Application
Web Based Self Service
Work Management System

COLUMBIA STATEMENT NO. 118-R

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

RACHEL FORD

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. Rachel Ford, Southpointe Industrial Park, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

Q. Are you the same Rachel Ford that served direct testimony in this proceeding?

A. Yes.

Q. What is the purpose of your rebuttal testimony?

A. The purpose of my rebuttal testimony is to respond to the direct testimony of witness Rachel Mauer, filed on behalf of the Bureau of Investigation and Enforcement ("I&E").

Q. What issues will you be addressing in this testimony?

A. I will address Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or "Company") proposed "Count on Columbia" ("Program" or "Count on Columbia") program.

Q. What is I&E's position on Count on Columbia?

A. In I&E Statement No. 4, Page 4, I&E witness Maurer recommends that "Columbia not be permitted to recover an additional $300,000 from ratepayers to fund the proposed Count on Columbia program."

Q. Do you agree with I&E's recommendation?

A. No.

Q. What matters will you rebut?

A. I will respond to the following issues raised by I&E:

- Columbia's proposed "Count on Columbia" ("Program");
- the Company's frequent base rate cases should be sufficient to "aid consumers in understanding the increasing cost of service;"

- Columbia's Public Awareness Program already addresses the importance of its facilities and infrastructure and the "goals of Count on Columbia and the Public Awareness Program are both focused on the Company infrastructure and natural gas safety;"
- the Pennsylvania Public Utility Commission's ("Commission" or "PUC") Policy Statement Regarding Utility Service Outage Public Notification Guidelines does not apply; and
- the notion that the Company's J.D. Power customer satisfaction scores do not support the idea that Columbia needs to spend more on educating its customers.

Q. How do you respond to the statement that Count on Columbia is simply additional advertising.

A. As stated in my Direct Testimony, the proposed Count on Columbia is a customer education program designed to drive awareness and education among Columbia's customers on the positive benefits that the Company's infrastructure replacement program will have on natural gas safety, affected communities and the economy. Because the Company is now filing its fourth rate case in five years, and will invest more than $140 million to replace infrastructure in 2013 alone, the Company is sensitive to the impact that its infrastructure replacement and regulatory initiatives can have on its customers' economic situations and recognizes that its customers will benefit from a better understanding of the reasons behind the Company's filings.

While the use of advertising methods to educate customers will certainly be part

of Count on Columbia's outreach strategy, the goal of the Program is not to focus on company "image" as witness Maurer's testimony suggests, but rather to distinguish the differences between distribution services and natural gas supply, as well as help customers understand that low, stable gas prices do not eliminate the need for continued pipeline replacement projects in addition to the work force and community benefits such a massive pipeline replacement effort supports.

Q. Please explain why the Company's frequent base rate cases have not sufficiently educated consumers in understanding the increasing cost of service.

A. It appears to be I&E's contention that frequency of utility base rate proceedings equals customer education solely on its own accord. I&E purports that "the fact that Columbia has filed cases approximately every two years since 2007 should have adequately instructed customers about the Company's increase costs of service," and the fact is that it has not. In fact, the Company has filed even more frequently than I&E suggests, actually filing four rate cases in the last five years, and customers still do not understand the reason Columbia is filing. The information Company witness Kempic provides in his initial and supplemental responses to data request I&E-RS-1-D, (Exhibit RVF-1R to my rebuttal testimony) includes some of the customer complaints and letters opposing the rate increase—it is evident that the Company's frequency of rate cases since 2008 has not been sufficient on its own to aid consumers in understanding the increasing cost of service. Comments include:

- "I object to Columbia Gas rate increase because of a newspaper report that Marcellus contains 330 Trillion cubic feet of gas."
- "With the massive amount of natural gas being accumulated as a result of local drilling, there should be no need for an increase in cost. On the contrary, rates should (if anything) be reduced."
- "Pennsylvania is sitting atop a huge supply of natural gas in the Marcellus and Utica shales. Why, then, is an increase needed by this supplier?"

Clearly there is a lack of understanding between the cost drivers of distribution services and natural gas supply. Customers do not understand that Marcellus Shale production, while fortunately helping to keep natural gas prices low and stable, is wholly unrelated to the need for infrastructure replacement efforts.

In addition to customer confusion, the media seems to lack an understanding as well. An October 4, 2012 news segment on KDKA-TV in Pittsburgh ran with the title, "Natural Gas Companies Want to Raise Fees, Despite Drop in Gas Prices." Exhibit RVF-1 R.

The Company is filing a rate case to recover its pipeline investments, not to make up for natural gas prices remaining low. As stated in Company witness Kempic's 2011 testimony (Pennsylvania Public Utility Commission v. Columbia Gas of Pennsylvania, Inc., Docket No. R-2010-2215623, Columbia Statement No. 2 page 6), replacing infrastructure has a dramatic effect on Columbia's revenue deficiency which has an impact on the level and structure of base rates. For example, three short months after Columbia's 2010 rate increase went into effect, the Company already began to suffer from a revenue deficiency. As long as

Columbia is engaged in replacing infrastructure, the rate increases will continue, despite abundant natural gas supply. When Columbia is investing more than $100 million per year in infrastructure, educating customers is critical to the public's acceptance of its local utility maintaining a safe and reliable system. Count on Columbia is not a brand awareness program, but instead recognition on behalf of the Company that part of our job is educating our customers on what they pay for each month. Customers will obtain a better understanding of how the company's pipeline replacement projects personally impact their safety, community and their bills.

Q. Why is the budget of $300,000 an appropriate amount to spend for the Count on Columbia Program?

A. As discussed in my direct testimony, the Company spent an average of $600,000 per year over three years to educate customers on Columbia's CHOICE® program, and comparably, the proposed Count on Columbia budget is half of that budget. With the proposed budget, the Company has attempted to strike a balance in creating an educational program that will achieve the Company's educational goals at the lowest possible cost. In preparing the proposed budget, Columbia evaluated its past CHOICE® education budget, as well as its current public awareness budget, and determined that a modest start will allow the Count on Columbia program to remain manageable as it grows. Based on the Company's experience with its other educational programs, Columbia believes that the budget proposed by the Company is a sufficient start towards educating the Company's customers relative to infrastructure investment.

Q. Please explain the difference between Count on Columbia and the Public Awareness Program.

A. Count on Columbia is designed to educate customers on the distinction between distribution services and natural gas supply, while demonstrating the true value that the Company's infrastructure replacement program has on natural gas safety, the economy and the communities we serve. Columbia's Public Awareness Program, pursuant to Federal Regulations, is a public education program that follows the guidance provided in the American Petroleum Institute's ("API's") Recommended Practice ("RP") 1162. The goal of this program is to educate customers and excavators on natural gas safety and the importance of calling before you dig.

While the two programs dovetail with each other, they are two separate programs with very different goals. The Public Awareness Program does not address the importance of the Company's facilities and infrastructure as witness Mauer suggests, but rather is more focused on "8-1-1" or "calling before you dig," what to do if a customer smells gas, etc. When I refer to "natural gas safety" as part of the goal of Count on Columbia, I am referring to the fact that the more a customer is educated on the importance and need to replace aging infrastructure and how that replacement is paid for, the better the customer will understand the link between replacement and safety, and the link between base rate filings and safety.

While the Company already recovers advertising monies that are educational in nature with regard to billing, rates and supply, it is clear from the letters from our

customers that the current education efforts are not enough (Exhibit RVF-1 R).

Q. Witness Maurer suggests that "the Company may need to change the current methodology used for advertising instead of spending additional money on advertising." Please explain Columbia's current advertising efforts.

A. Columbia's current advertising efforts are already educational in nature. As a company, we use the limited funding available to communicate messages about natural gas safety and available low-income assistance programs, as well as to demonstrate Columbia's commitment to our customers' and our communities through our infrastructure replacement program. Outreach strategies in 2012 included grassroots community sponsorships and print, radio and television advertising.

Q. Is it your contention that the Commission supports the notion of customer education efforts?

A. Yes. As stated in my direct testimony, I fully understand that the Commission's Statement Regarding Utility Service Outage Public Notification Guidelines is focused on improving communications during public outages. My point is simply to acknowledge that the Commission does support increased customer communication and outreach, and this Statement is an example of that. It is the Company's experience that its customers appreciate being informed of outages, rate increases, and issues that affect their service. Only through an expanded customer education program, such as the proposed Count on Columbia, will customers truly understand their natural gas distribution service, and how base rate cases impact their service.

Q. Is Ms. Maurer's analysis of the J.D. Power information you use in your Direct Testimony accurate?

A. No. The Company is neither proposing an increase to advertising dollars, nor simply requesting a blank check to spend how it deems appropriate to market the Company's image. Rather, Columbia is proposing a customer education program that will serve to educate customers where a demonstrated lack in knowledge exists about customer bills and rates. The J.D. Power results support the knowledge gap Columbia has identified. The 2011 J.D. Power results demonstrate that more customers recall messages about their natural gas bills and price rate changes as compared to recalling company image and natural gas safety. From a communications perspective, this indicates that the Company needs to expand its current efforts to ensure customers understand the reasons and benefits behind changes to their natural gas bill because they are paying more attention to messages about their natural gas bills and price rate changes. As explained throughout this testimony, customers do not understand that an increase in rates is due to infrastructure, and not gas costs. The results of the customers' letters are not exhaustive, but rather when this information is reviewed comprehensively with the 2011 J.D. Power results it is evident that customers most likely do not understand the reasons and benefits behind those changes.

Q. Does this conclude your testimony?

A. Yes it does.

Natural Gas Companies Want to Raise Fees, Despite Drop In Gas Prices
KDKA

Oct. 4, 2012

PITTSBURGH (KDKA) – With Marcellus Shale drilling rigs dotting our region, the price of natural gas has dropped to a ten-year low.

So many want to know why Colombia Gas is seeking a more than 23 percent rate hike.

They have drilled so much natural gas in our region that companies have actually cut back drilling.

There is an abundance of natural gas.

"I'd like to see rates come down," Columbia Gas customer Kate McGrady said. "If natural gas is more plentiful then we should pay less. It just seems to me that, that's the way it works."

Even so, Columbia Gas — which has more than 400,000 customers in Pennsylvania, mostly in our area — is seeking a huge rate hike of 23.4 percent.

An average customer's bill will rise from $67 to $83 per month.

"I feel like we're paying a lot already," said Michelle Urresta, who's also a Columbia Gas customer. "No, I don't agree with it at all."

"It's unconscionable in these times," another Columbia Gas customer, Rose Marie Mazza, said.

So why such a big increase?

Columbia gas says it needs to raise rates to collect some of the hundreds of millions of dollars they've invested over the past five years on projects like one that's in operation in Mount Lebanon.

They're repairing and replacing aging underground gas lines.

The gas company says it's replaced $400 million worth of pipeline the past five years. And they'll spend more than a $100 million on new pipeline this year.

"I do think we need the infrastructure taken care of," Mazza said. "It's vital to the area."

But when asked if that justifies the increase in cost, Mazza said, "I just feel like it's too much, like we pay too much for it."

And Columbia is not alone.

Equitable is seeking a 71-cent-per-month surcharge to purchase and upgrade two pipeline systems.

Peoples Natural Gas already got a 13 percent rate increase to pay for its pipeline repairs.

The hikes follow a new state law that allows utility companies to recover infrastructure costs through rate hikes.

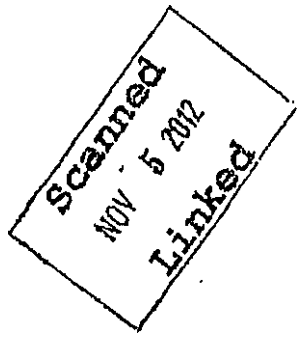
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11/13/12
J. Good VM

L-2012-2321748

TELEPHONE [redacted]

FROM THE DESK OF [redacted]

CELL PHONE [redacted]



October 24, 2012
Pennsylvania Public Utility Commission
P. O. Box 3265
Harrisburg, PA 17105-3265

Dear PUC,

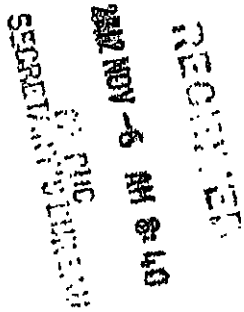
I am objecting to the rate increase Columbia Gas of Pennsylvania is requesting by Nov. 27.

According to information Columbia Gas has provided, they are requesting a rate increase of more than 23% for their average household customer who uses 73 therms a month. In my last bill I used 57 therms of natural gas which means my rate increase could exceed 25% since, according to their information, the more gas used the less the percentage of rate increase.

This is too much for a company that has not provided good service. Columbia Gas had indicated some time ago it was going to come and bury gas meters in front of homes along Franklin Farms Road. This has not been done even though there has been a huge increase in truck traffic moving industrial equipment on the road. This traffic increase, due to Marcellus Shale gas drilling less than a mile from my home, has made the need to bury these meters a safety issue.

Which brings me to another point: Pennsylvania is sitting atop a huge supply of natural gas in the Marcellus and Utica shales. Why, then, is an increase needed by this supplier? In their proposed rate change notice to customers they did not even give a reason for the request.

I urge you to not allow this increase to go through.



Sincerely yours,

[redacted]

[redacted]

A Note For You

I object to Columbia Gas rate increase because of a newspaper report that recently contains 330 billion cubic feet of Gas.

Thank you

[redacted]

Pennsylvania PUC
NOV 14 2012
Consumer Services
CAC Division

SCANNED
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LINKED



...prevent existing rates from changing until it investigates and/or holds hearings on the request. The company must prove that the requested rates are reasonable. After examining the evidence, the PUC may grant all, some, or none of the request, or may reduce existing rates. The PUC may change the amount of the rate increase requested by the utility for each customer class. As a result, the rate charged to you might be different than the rate requested by the company as shown above.

Continued on back

To Whom It May Concern, 16 November 2012

In reference to the proposed rate hike by Columbia Gas of PA, I offer the following:

1. With the massive amount of natural gas being accumulated as a result of local drilling, there should be no need for an increase in cost. On the contrary, rates should (if anything) be reduced.

2. Due to the change implemented with their LIHEAP program, which involves making financial assistance more difficult, people such as myself are unable to obtain help with current rates. This was a result of the maximum income amount allowed to be eligible being reduced from previous years.

3. The difference in the amount of increase for residential, commercial, and industrial customers is proportionally unfair to say the least.

4. The majority of distribution pipeline repair work is performed on pipes leading into the customers homes, which the customer is responsible for paying repair costs.

Having said this, I would humbly request the PUC give long thought and consideration on granting a rate increase at this time.

Regards,

[redacted]

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Pennsylvania PUC
NOV 26 2012
Consumer Services
CAC Division

COLUMBIA STATEMENT NO. 119-R

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

ERICH A. EVANS

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Are you the same Erich Evans that filed testimony in this proceeding?

A. Yes.

Q. What is the purpose of you rebuttal testimony?

A. The purpose of this rebuttal testimony is the respond to the direct testimony of witness Lisa A. Boyd filed on behalf of the Bureau of Investigation & Enforcement and witness Glenn A. Watkins filed on behalf of the Pennsylvania Office of Consumer Advocate. In her testimony Ms. Boyd states that she finds merit in developing ways to make line extensions more affordable to customers. While Mr. Watkins goes further to say "I applaud Columbia for proposing an alternative and voluntary method to assist consumers" and "I do not recommend the rejection of the concept" (OCA statement No. 3 pages 30 & 31). They both recommend changes to the proposed Rider NAS that I will address in my rebuttal testimony.

Q. Ms. Boyd states that there may be benefits for Pilot Rider NAS but right now the proposal requires more thought and a better design. Do you agree?

A. No. I will respond to all of the points raised by Ms. Boyd below. However, Columbia maintains that Pilot Rider NAS will benefit those customers that want to begin to receive natural gas service and that no delay is warranted.

Q. On page 5 of her testimony Ms. Boyd suggests that Columbia should reduce the maximum payment term for Pilot Rider NAS from 20 year to 10 years, do you agree with this suggestion?

A. No. Although Columbia is not opposed to a different payment term, a 10 year term may be an inadequate length of time. Ms. Boyd's single argument for the

reduction of the proposed 20 year term is that the customers would accrue less interest with a 10 year term. This is short sighted and ignores other implications caused by a reduction in term. By reducing the payment term to 10 years, the interest costs incurred by the customers would decrease, however, the customers' monthly cost would subsequently increase to pay the principal cost of the extension over a shorter term. In fact, with a 10 year term the monthly cost is likely to increase above $35 per customer, as shown in I&E Exhibit No. 5. Even an increase of just over $10 more per month could make the program cost prohibitive for customers. However, if a customer wishes to decrease the length of the term, customers would have the option of paying more than the monthly rider amount. This would be an effective means for customers to pay off the balance faster than the 20 years, if the customer wishes to do so.

Further, a longer term and lower monthly cost provides other benefits. Lower payments would equate to a lower rate of default for Pilot Rider NAS. This would prevent further impacts on Columbia's other customers.

For these reasons, Columbia continues to submit that a 20 year term is appropriate. As proposed, the 20 year term results in a lower monthly customer cost.

Q. On page 6 of her testimony, Ms. Boyd suggests that the $25 maximum monthly payment should be eliminated. Do you agree with this suggestion?

A. No. Columbia proposed the monthly cap to ensure that a large number of customers would benefit from Pilot Rider NAS. The monthly cap also ensures that the monthly payment stays low and provides another way to keep Pilot Rider

NAS affordable to customers. Given that some customers may be willing and able to pay more, Columbia would be receptive to raising the cap to $35, but not removing the cap completely. This would allow a larger amount per customer to be put into Pilot Rider NAS, and still keep the amounts low enough to allow more customers to take advantage of Pilot Rider NAS.

Q. On pages 7 and 8 of her testimony, Ms. Boyd recommends that Columbia change the eligibility for Pilot Rider NAS. Do you agree with her proposal to limit it to individual residential customers?

A. No, Columbia proposed Pilot Rider NAS as a rider that could be offered to any line extension project as long as the project is primarily residential. This is essential to making the pilot as beneficial as possible to customers and the Company. Ms. Boyd has not thought through all of the implications of limiting the rider to individual residential customers. Such a limit would restrict the applicability of the rider to only a few customers.

As an example, Columbia had a project in which a rural school and some adjacent homes wanted to covert to natural gas. Had Pilot Rider NAS been available, it would have been a useful tool to make the project affordable for these customers. However, if Pilot Rider NAS is limited to only individual residential customers Columbia would not be able to offer it in a similar situation.

Another common situation occurs when a developer is working on a new housing development. The developer may request a main line extension project that will pass by 10 to 12 existing homes that do not have natural gas service. If Columbia is able to offer service to the existing homes by combining the project with the

one for the new housing development, it will reduce the overall costs for all parties. However, if the Pilot Rider NAS is restricted to individual, residential customers, the Company could not offer Pilot Rider NAS as an option to developers.

Q. In the previous example, if Pilot Rider NAS were limited to individual residential customers wouldn't the Company be able to offer it to each individual customer, in the above example?

A. While Columbia would be able to offer Pilot Rider NAS to each individual customer, the Company would be forced to consider each one a separate project and not combined. This would raise the costs for each residence because they could not count on the revenue from the other homes to justify the main line extension. Columbia would have no way of knowing which customers were going to say "yes", and thus each project would have to assume that it was the only customer. This would increase the base cost for each customer because the cost of the main line would not be spread across the group. Therefore this limitation would actually make Pilot Rider NAS much less useful, and it is very likely that such a modification would increase the initial deposit amounts for customers. These higher deposits could discourage customers from proceeding with projects.

Q. Please comment on Ms. Boyd's argument that commercial and industrial customers could use up all of the money and that they should not be eligible to use Pilot Rider NAS?

A. This is why Columbia proposed that Pilot Rider NAS should be used only for projects that are, at least, primarily residential. Columbia does agree that

residential customers should get most of the benefit from Pilot Rider NAS, but to place the limit that it can only be used for residential customers would exclude many projects that make Pilot Rider NAS on the whole, more economical. The previous example of a school and residential customers is a perfect reason why Pilot Rider NAS should not be limited to residential only. Columbia does agree that if a project is only commercial or industrial (or more than 50% commercial and industrial) then it should be excluded, but to exclude a project that is mainly residential and happens to also contain a commercial or industrial piece does not make sense. This would place too great a limit on Pilot Rider NAS and lessen the effectiveness of the program.

Q. On page 9, Ms. Boyd suggests that the Company provide more information to customers, such as projected usage when a customer is considering a main extension in order to convert to natural gas. Do you agree with this suggestion?

A. The Company is not opposed to providing usage information to a potential customer. However, the Company tries to use the customer's supplied usage information when evaluating a line extension. Only in cases where the customer has no information or needs help determining their usage would the Company develop the usage estimate. The customer is much more knowledgeable about how much gas they will use and is able to provide a more accurate usage number. They know what type of equipment they will be installing and the ultimate use of the gas. Further, the customer knows the size of their home, the living habits, and many other variables to which Columbia does not have access.

Q. Ms. Boyd suggests on page 10 of her testimony that biennial reconciliations be

done for Pilot Rider NAS, where the customer's usage, payment, balance of line extension cost, and the number of meters added are all reviewed. She also suggests reconciliations any time "meters are added or removed or if the customer serviced by Rider NAS meter changes." Does Columbia agree with these recommendations?

A. No. When Columbia developed the proposed Pilot Rider NAS it did so with both the customer and Company in mind. It appears that Ms. Boyd's suggestion does not consider all aspects of line extensions. Today, customers are faced with paying all of the deposit cost up front if they want to receive gas service. Pilot Rider NAS, if approved, would allow customers to pay the customer portion of the cost of the line extension over time. Therefore, the customer's decision is based on their ability to afford the extra monthly payment. A levelized payment greatly assists the customer in making this decision. However, if the program is modified to allow for biennial reconciliations and reconciliations any time something changes, the customer would never have any comfort in their payment amount. This change would pose too much risk of the unknown to the customer. According to Ms. Boyd's suggestion, the customer would not necessarily know when a reconciliation was going to take place. They would know about the regular scheduled reconciliation, but not the ones caused by meters being added or removed in the project. In a large development this could lead to seemingly endless reconciliations.

Similarly, Ms. Boyd's suggestion that a reconciliation occur when meters are removed would negatively affect the customer's monthly payment. That is, under

this proposal, the customer could receive an increase in payment based exclusively on what their neighbors decide to do. Columbia does not see benefit in this proposal and is concerned how customers will respond to the potential fluctuation in their monthly Pilot Rider NAS charge—particularly an upward fluctuation.

Further, Ms. Boyd's suggestion has the potential to increase the chance of default. If the reconciliation would raise the payment, the customer may be unable to afford the increase and then default on their obligation. Another risk is customer dissatisfaction. By constantly reviewing and modifying the payment, the customer could become frustrated and unhappy with the program. For these reasons Columbia decided that the program should provide a fixed monthly payment that is only reviewed at the end of the term. Columbia believes that customers would prefer to have a fixed monthly payment amount, as this would limit customer confusion and result in higher customer satisfaction.

Q. Are there any other issues with the suggestion of biennial reconciliations and reconciliation with every change?

A. Yes, performing these reconciliations would also increase the administrative costs. Columbia would incur increased costs of programming this change into their system as well as increased personnel costs in administering Pilot Rider NAS with biennial and other miscellaneous reconciliations.

Q. Ms. Boyd suggests that these reconciliations would provide additional details and information during the pilot of Rider NAS. Do you have any comments on this idea?

A. Yes, Columbia does understand the need for data and information during the pilot of Rider NAS. As proposed, Columbia will provide sufficient data to allow the Commission and interested parties to evaluate the Pilot Rider NAS, and Columbia does not feel that changes to the program are needed just to provide more data for the pilot. Under the current design, Columbia will be able to provide the following: number of customer offered Pilot Rider NAS; number of customers accepting Pilot Rider NAS; total due annually; total paid annually; number of defaults; total meters added; total meters added with Pilot Rider NAS; and total balance of Pilot Rider NAS. These items will provide sufficient information to determine the effectiveness of the program.

Q. Ms. Boyd suggests that at the final reconciliation when the term ends that any overpayments be refunded and underpayments be absorbed into rate base. Do you agree with these recommendations?

A. Yes. Currently Columbia's systems would stop the payments when the balance is paid so a customer should never get into an overpayment situation, but if that did happen Columbia would refund the amount to the customer. At the end of the term, if the balance is not paid, Columbia would be willing to leave this amount in rate base and not charge the customer for the underpayment.

Q. In her testimony, Ms. Boyd claims that the proposed Pilot Rider NAS would result in double recovery of the deposit. Do you agree?

A. No. As proposed, Pilot Rider NAS would not allow Columbia to double recover the deposit. Columbia's proposal would put the Pilot Rider NAS balance into rate base, charge the customer a monthly fee, credit rate base as the payments are

received and credit the cost of service with the interest received.

For example, if a customer is faced with a $2880.77 main extension deposit that qualifies for Pilot Rider NAS, that customer would be charged a monthly fee of $25 (assuming an 8.5% interest rate with the 20 year term.) The $2880.77 would be added to rate base, and credits will be made as the payments are received. For the sake of simplicity, let's assume that the payments start when new rates go into effect from Columbia's base rate case. As a result of this hypothetical rate case filing, the $2880.77 would be in the allowed rate base. During the next twelve months, the customer would pay $300. Of that annual rider amount, $57.34 would be used to reduce rate base which would leave $2823.43 in rate base from the original amount. The remainder of the payments, $242.66, would be credited against the cost of service. If Columbia is granted an 8.5% return on equity in this hypothetical rate case, Columbia would earn $239.99 ($2823.43 * 8.5%) on the amount in rate base, but credit all customers back $242.66 in the cost of service. The net effect is a credit to the customers of $2.67. Therefore, no double credit will take place. The details of this example are included as Attachment A to this testimony.

Q. One of Ms. Boyd's arguments is that the credits to the cost of service are so small that they would not have any impact on the cost of service. Do you have any comments on this statement?

A. Yes. I would agree with Ms. Boyd that the credits each year are small. However, this ignores the fact that the addition to rate base is also small. This is part of the way Pilot Rider NAS was designed--it limits the amount Columbia will spend.

This has the effect of limiting how much will go into rate base and a corresponding effect is that the interest credits are also small. If Ms. Boyd's position is that the amounts are too small to worry about, then it should not be an issue to put the full $1 million into rate base each year. As shown in my previous example, the interest credits more than offset the rate base impact of the Pilot Rider NAS amounts and therefore cause no harm to the other customers.

Q. Does Ms. Boyd have a counter proposal for how to handle the interest and credits to rate base?

A. Yes, Ms. Boyd suggests that Columbia realize no increase in rate base, but be allowed to keep the interest income from the Pilot Rider NAS payments. This suggestion, in effect, would require Columbia to act like a commercial bank to customers. When her whole proposal is fully examined the gaps are quite evident.

Q. What gaps exist in her proposal?

A. Ms. Boyd is suggesting that Columbia act as a commercial bank without the benefits of being a commercial bank. This would either increase the cost of offering Pilot Rider NAS or severely limit to whom Pilot Rider NAS is offered.

Q. How would this increase the cost of the service?

A. Commercial banks charge interest based on their cost of capital and the risk involved with the loan. Therefore, the payments they receive from all customers allow them to offset what they lose to default. If Columbia were to act the same way, the Company would need to charge a premium on top of its cost of capital to customers. This would make Pilot Rider NAS more expensive. In addition,

Columbia would also have more up front work to do to evaluate credit and determine the interest rates to charge, which would increase the administrative costs of Pilot Rider NAS.

Q. You also state that another consequence would be to severely limit to whom Pilot Rider NAS is offered. How would that happen?

A. If Columbia were to act like a commercial bank, the Company would have to handle the customer in the same manner as a bank. This means the Company would be more selective about which customers are offered Pilot Rider NAS. This would also serve to further limit the effectiveness of Pilot Rider NAS. For this reason Columbia believes it is appropriate to implement Pilot Rider NAS by placing amounts into rate base and providing credits to rate base and the cost of service as payments are made by customers.

Q. Ms. Boyd states that Columbia should not terminate customers for non-payment of the Rider Pilot NAS charges. Do you agree with this suggestion?

A. While this could result in Columbia being more selective (by using higher credit standards) on which customers are offered Pilot Rider NAS, the Company would agree to not terminate service for non-payment of the Pilot Rider NAS charges.

Q. Ms. Boyd suggests that Columbia should include an incentive offer as part of its line extension policy. What do you think of this suggestion?

A. Columbia is not opposed to the idea of an incentive offer, as long as the Company can recover the cost of the incentives. As Ms. Boyd points out incentives can reduce the amount of deposit required because it reduces the overall cost of a line extension for a customer. This happens because the company grants a certain

amount of mainline extension to any new customer or provides a cash credit towards each new line extension. The costs of the free portion of the line extension or cash credit would be included in Columbia's rate base which leaves a smaller amount of the full cost of the line extension as the new customer's responsibility.

Q. Do you see any problems with an incentive offer?

A. One potential problem with an incentive offer is that Columbia does not have as much control of how much extra capital is spent. In theory, an incentive offer could be developed to provide the same benefit as Pilot Rider NAS. This would allow customers to be added to the system with little or no deposit. However, under Pilot Rider NAS Columbia has a limit of $1 million per year. This limit exists so that Columbia does not harm the infrastructure replacement program by allocating too much capital to offer Rider NAS. Incentive offers typically do not have a limit and apply to all customers equally. This could cause Columbia to spend more than their proposed $1 million additional to add new customer which could force them to divert funds away from the infrastructure replacement program.

Q. In his direct testimony Mr. Watkins suggests that the commission delay ruling on Pilot Rider NAS until a collaborative group determines how such a program could be implemented. Do you agree with this suggestion?

A. No. Columbia has proposed Rider NAS as a pilot. I believe it would be more beneficial to put the rider in place as part of the overall rate case decision. A collaborative group could then be formed to review the effectiveness of Pilot

Rider NAS and recommend changes for a full program at the end of the pilot.

Q. Mr. Watkins recommends that the monthly payment cap be raised and a shorter term for the Pilot Rider NAS payments be established. Do you agree with these suggestions?

A. Columbia is willing to agree to a higher monthly payment cap, as previously stated. However, some other considerations need to be taken into account to make sure the changes do not impact the effectiveness of Pilot Rider NAS, and in no event can the overall $1 million budget be increased.

Q. Mr. Watkins also states that he feels it is improper to disconnect service if a customer fails to pay the Pilot Rider NAS amount. Do you have any comments on this suggestion?

A. My comments are the same as earlier; Columbia agrees not to disconnect service if a customer does not pay the monthly Pilot Rider NAS charges. The unpaid balance would then remain in Columbia's rate base.

Q. Mr. Watkins describes a situation that could arise and would cause inequities by the reconciliation at the end of the Pilot Rider NAS term. What are your thought on this situation?

A. Mr. Watkins describes a situation where ten customer meters are added initially and during the Pilot Rider NAS term one of the properties becomes vacant. Then at the end of the Pilot Rider NAS term a reconciliation is completed and the other customers have to keep paying to make up the difference. This situation could be eliminated by adopting Ms. Boyd's proposal that specifies any unpaid balance should remain in rate base at the end of the term. In other words, after a final

reconciliation overpayments will be refunded to customers while unpaid balances will not be charged. Columbia believes that Ms. Boyd's suggestion is one that should be adopted and would therefore eliminate this situation described by Mr. Watkins.

Q. On page 18 of her testimony, Ms. Boyd objects to Columbia's proposal to use additional funds, such as pipeline refunds, to buy down deposits for Rider NAS. Do you agree with her objection?

A. No. Columbia has proposed that if it receives any additional funds, such as pipeline refunds, that it would apply to the Commission to use those funds to help buy down the cost of deposits. This would assist in growing the customer base and would then allow costs to be spread across more customers. Ms. Boyd's only argument against this is that the impact on other customers would be "infinitesimally small".

Q. Mr. Watkins also objects to the use of pipeline refunds to buy down line extension deposits. Do you agree with his comments?

A. No. Mr. Watkins states that Columbia intends to "divert the practice of applying pipeline refunds to the hardship fund to the unpaid balances of loan participants." (OCA Statement No.3 Page 32) While Columbia, in recent years, has been authorized to apply pipeline refunds to the hardship fund it is not a foregone conclusion that the Commission would allow Columbia to continue this practice. In addition, he misstates Columbia's intention. Columbia is proposing to request permission to use pipeline refunds, or other funds, when and if they are available, to set up an account where they could buy down deposits for

customers. This would not be applied to existing deposits, but for deposits going forward. They would be used on a first come, first serve basis to help with new line extensions. Columbia's intent is to make a request with the Commission when funds are received. When this happens Columbia would not be opposed to using part of the refund to buy down deposits and part in other ways, such as the hardship fund.

Q. *Does this conclude your rebuttal testimony?*

A. Yes.

Pilot Rider NAS

Twelve months of payments and impact on rate base

Customer Agrees to Rider NAS
Amount Financed is $2,880.77
Fixed Interest rate of 8.5%

Pmt. No.	Payment Date	Beginning Balance	Customer Payment	Principal	Interest	Ending Balance
1	8/1/2013	$2,880.77	$25.00	$4.59	$20.41	$2,876.18
2	9/1/2013	$2,876.18	$25.00	$4.63	$20.37	$2,871.55
3	10/1/2013	$2,871.55	$25.00	$4.66	$20.34	$2,866.89
4	11/1/2013	$2,866.89	$25.00	$4.69	$20.31	$2,862.20
5	12/1/2013	$2,862.20	$25.00	$4.73	$20.27	$2,857.47
6	1/1/2014	$2,857.47	$25.00	$4.76	$20.24	$2,852.71
7	2/1/2014	$2,852.71	$25.00	$4.79	$20.21	$2,847.92
8	3/1/2014	$2,847.92	$25.00	$4.83	$20.17	$2,843.09
9	4/1/2014	$2,843.09	$25.00	$4.86	$20.14	$2,838.23
10	5/1/2014	$2,838.23	$25.00	$4.90	$20.10	$2,833.33
11	6/1/2014	$2,833.33	$25.00	$4.93	$20.07	$2,828.40
12	7/1/2014	$2,828.40	$25.00	$4.97	$20.03	$2,823.44
			$300.00	$57.34	$242.66	

Pilot Rider NAS

Twelve months of payments and impact on rate base

Impact to Rate Base

Payment Date	Amount Added to rate base	Credit to Rate Base	Balance in Rate Base
8/1/2013	$2,880.77	$4.59	$2,876.18
9/1/2013		$4.63	$2,871.55
10/1/2013		$4.66	$2,866.89
11/1/2013		$4.69	$2,862.20
12/1/2013		$4.73	$2,857.47
1/1/2014		$4.76	$2,852.71
2/1/2014		$4.79	$2,847.92
3/1/2014		$4.83	$2,843.09
4/1/2014		$4.86	$2,838.23
5/1/2014		$4.90	$2,833.33
6/1/2014		$4.93	$2,828.40
7/1/2014		$4.97	**$2,823.44**

	$2,823.44	Rate Base
*	8.50%	Allowed Return
Added to Cost of Service	$239.99	

Interest credits to cost of service

Payment Date	Credit to Cost of Service
8/1/2013	$20.41
9/1/2013	20.37
10/1/2013	20.34
11/1/2013	20.31
12/1/2013	20.27
1/1/2014	20.24
2/1/2014	20.21
3/1/2014	20.17
4/1/2014	20.14
5/1/2014	20.1
6/1/2014	20.07
7/1/2014	20.03
Total Credit to Cost of Service	242.66

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2012-2321748
	:	M-2012-2323645
Office of Consumer Advocate	:	C-2012-2330240
Office of Small Business Advocate		C-2012-2330539
Anastasia Stratigos	:	C-2012-2330724
Louis and Joanne Quahliero	:	C-2012-2332087
Angela Burnett	:	C-2012-2332497
G. Thomas Smeltzer	:	C-2012-2333247
Michelle Swartz	:	C-2012-2328788
Columbia Industrial Intervenors	:	C-2012-2334026
Johanna Shigle	:	C-2012-2336033
	:	
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Joel L. Hoelzer, being Vice President of Human Resources of NiSource Corporate Services Company ("NiSource"), hereby state that the testimony set forth in Columbia Statement No. 120-R is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013

Joel L. Holezer

COLUMBIA STATEMENT NO. 120-R

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission,	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2012-2321748
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Columbia Gas of Pennsylvania, Inc.	)	
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REBUTTAL TESTIMONY OF

JOEL L. HOELZER

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. What is your name, position, and business address?

A. My name is Joel L. Hoelzer, and I am Vice President of Human Resources for NiSource Corporate Services Company ("NCSC"). My business address is 200 Civic Center Drive, Columbus, OH.

Q. Please provide an overview of your background and education.

A. I received a Bachelor of Science degree in Business Administration from The Ohio State University in 1981 and a Masters in Business Administration from The Ohio State University in 1983. I am a certified Senior Professional in Human Resources ("SPHR"). I have been in the human resources function with NiSource and the predecessor Columbia Energy Group since 1983.

I have held the position of Vice President Human Resources at NiSource since March 2006. Before my current position, I was the Vice President of Field Human Resources for NiSource. Prior to that, I held numerous roles in the human resource area throughout Columbia Energy and NiSource, including compensation manager for the Columbia Gas Distribution Companies.

Q. Have you previously filed testimony in this matter?

A. No.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony filed in this proceeding by the Bureau of Investigation and Enforcement witness Christine Wilson and to testimony filed in this proceeding by the Office of the Consumer Advocate witness Thomas S. Catlin.

Q. Please briefly describe the position of Ms. Wilson regarding incentive compensation, profit sharing, and stock awards.

A. Ms. Wilson proposed disallowing 50% of incentive compensation, 100% of profit sharing, and 100% of stock awards for Direct and NCSC employees from the determination of Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or "the Company") revenue requirement. Ms. Wilson claims that a large emphasis of the incentive plan is the NiSource earnings per share target, and therefore shareholders and ratepayers should share the cost of incentive compensation. She further proposes that profit sharing and stock awards should not be allowed.

Q. Please briefly describe the position of Mr. Catlin regarding profit sharing and Phantom Stock.

A. Mr. Catlin proposed disallowing the costs associated with the Company's profit sharing plan and costs related to Phantom Stock. Mr. Catlin claims that the costs associated with the Company's profit sharing plan should not be recovered from ratepayers because financial targets should be set in such a way that the company "self supports" profit sharing, because profit sharing payments are not dependent of quality of service or meeting efficiency goals, and finally, because the incentive to improve financial performance is not necessarily consistent with ratepayer interests.

Q. Does Columbia agree with either Ms. Wilson's or Mr. Catlin's proposed adjustments?

A. No. I am advised by counsel that the Commission has allowed recovery of incentive compensation as a part of payroll where the compensation plan

includes provisions that are designed to provide benefits to customers, as the Company's plan does. Most recently, I am aware the PPL Electric Utilities decision that permitted incentive compensation consistent with prior Commission decisions when such compensation programs are focused on improving operational effectiveness. *Pa. PUC v. PPL Electric Utilities Corp.*, R-2012-2290597, (Order entered Dec. 28, 2012). In addition, profit sharing and stock rewards are part of the Company's design of its total rewards programs to remain competitive with other employers and further drive operational effectiveness within the Company.

Q. Please describe NiSource's compensation philosophy.

A. NiSource's "total rewards" philosophy is to compensate employees competitively in comparison with the utility industry as well as general industry employers in order to attract, retain and motivate qualified employees, while consistently meeting its requirements to provide safe, reliable and cost-effective service to its customers.

Q. Does NiSource employ a compensation and benefits consultant to assist with its total rewards programs?

A. Yes. NiSource regularly relies on the advice and guidance provided by Aon Hewitt ("Hewitt"), a global human resources consulting firm. Hewitt assists NiSource in setting competitive compensation, evaluating and recommending changes to the employee benefit plans, and providing salary and variable pay survey information.

Q. From a policy perspective, why is it important that 100% of Columbia and NCSC incentive compensation be recovered in base rates?

A. If the Commission allows only partial recovery of incentive compensation, it sends the message that variable pay is not valued as a viable tool to encourage company efficiencies and customer service. Further, it implies that fixed base pay, without incentives, is the preferable means to attract, motivate, and retain talented employees while retaining a reasonable opportunity for full recovery of that compensation. Incentive compensation is an element of competitive total compensation in the labor market both within the utility industry and within the broader employer base. This is evidenced by a recent survey conducted by Aon Hewitt. The following is an excerpt from the Highlights and Trends section of The Aon Hewitt 2011 Variable Compensation Measurement ("VCM") Report-U.S. Edition (September 2011):

> Highlights and Trends
> With the current prevailing economic environment variable pay plans are an increasingly critical component of most VCM participants' total compensation offerings. The Aon Hewitt VCM report continues to support the trend that companies are increasingly turning to variable pay as a means to attract, retain, and reward performance while traditional merit increase budgets remain at record low levels. In 2011, a median 99% of total U.S. employees who were eligible for at least one type of variable pay award actually received an award.
>
> Prevalence of Variable Compensation
> The frequency of companies with at least one broad-based variable pay plan continues to increase since 1994 when we first started recording this information. According to Aon Hewitt's Salary Increase Survey, in 1994, 60% of U.S. companies indicated they had at least one broad-based variable pay plan in place. By 2011, 92% of U.S. companies had implemented a broad-based variable pay plan.

> Not only have more U.S. companies in the survey group introduced broad-based variable compensation in recent years, companies also have changed the look of their variable pay plans.
>
> Organizations may have had one plan covering all employees in all locations and/or departments in recent years. However, these plans are now often being replaced by more customized variable compensation plans. Today, companies tend to design multiple plans for different employee groups. A typical mix of variable pay plans may include a business incentive plan with combined financial and operational performance criteria for staff functions. Individual performance plans give managers the power to reward and retain their top performers.

To remain competitive in today's labor market, it is important to provide incentive compensation and profit sharing as part of total compensation, similar to 92% of companies that have implemented broad based variable pay plans in the U.S. If the Company maintains a competitive base compensation, but does not provide variable compensation, the likely end result is that total compensation will lag the competition. Barring an offsetting increase in base pay structure, employees will have larger total compensation opportunities with other employers who provide competitive compensation that includes performance incentives.

Q. If incentive pay is reduced by Columbia, will fixed base pay have to increase to be competitive with other employers?

A. Yes. NiSource incentive compensation is part of total compensation required to maintain NiSource's competitive position with other utility and non-utility companies. Hewitt helped NCSC implement a base pay management program to establish the reasonableness of base pay on an ongoing basis across NiSource companies. A review of average base Company salaries compared to external

market medians indicate that we are paying within an appropriate market level. On average, employees are paid approximately 5% below market. Base compensation below market and no variable compensation would clearly result in total compensation even further below market. Absent variable compensation and to remain competitive, fixed base pay would have to increase in order to offset the variable incentive compensation component of total compensation. This increase in base pay would in turn be borne by customers. Although the increase in base pay might allow Columbia to remain competitive with other companies, it would leave the Company without a critical tool for motivating its employees to improve performance and create efficiencies, and for promoting an environment of strong safety and customer service.

Q. Are employees accountable for quality of service, efficiency, or safety goals?

A. Yes. Individual incentive award opportunities are based primarily upon achievement of goals that are specifically designed to create efficiencies, improve customer service, and promote safety, operational excellence, and continuous improvement, and not simply to increase shareholder value. These goals provide reinforcement to take actions that are in the best interest of the Company's customers.

Q. Please explain the Company's incentive planning and individual goal setting process.

A. Employee-specific goals are created using a performance management tool called "Performance Source," which is designed to cascade key performance goals throughout the organization. These goals are divided into four key categories,

including: Customer, Employee, Financial and Process, which become formalized and are embodied as specific objectives reflected in Performance Management Worksheets ("PMW") for each employee. For example, in the Company's operations department, the process begins with the General Manager of Operations for Columbia Gas of Pennsylvania, Mr. Kitchell, who sets goals for the Company in the Performance Source tool. Then he "cascades", or assigns, these goals to his direct reporting employees. These employees further cascade more specific goals, all of which support the broader goals established by Mr. Kitchell, to their respective direct employees. Ultimately, specific cost, safety and service goals are cascaded to individual employees throughout the organization. The PMW contains these annual performance objectives and articulates the means of measuring the employee's progress in relation to the objectives established. Each exempt employee is actively involved in the development of his or her PMW, with input from his or her supervisor, and the employee's progress is reviewed and discussed with the employee periodically throughout the year. The PMW process is also used as an aid in determining the amount of an incentive award for an employee.

The use of the PMW process to establish goals and to measure employees' performance against these goals is important in reinforcing the proper focus on key initiatives and goals designed to create efficiencies, improve customer service, and promote safety, operational excellence, and continuous improvement.

Q. Could you provide some examples of the use of objectives in the PMW process that are focused on benefitting customers?

A. Below is a table reflecting examples of objectives for the General Manager of Operations for Columbia Gas of Pennsylvania.

Objective	Performance Measure
Improved Safety Metrics	Achieve key safety milestones: DART (days away restricted time off) Rate, the OSHA Injury Rate, and Preventable Vehicle Accidents
Operational Compliance	Ensure 100% compliance with all regulatory and code required inspections
Emergency Response	Percent of priorities responded to in 60 minutes or less is 98% or greater
Customer related performance measures	Percent of customer generated appointments met is >=97%

Each of the objectives listed in the table are cascaded to the General Manager's direct reports as explained above.

Q. Do you agree with Ms. Wilson that 50% of incentive compensation for Direct and NCSC employees should not be recovered from rate payers?

A. No. This incentive plan is designed to encourage employees to achieve goals that are critical in reinforcing key Company initiatives, including safety, customer service, operational efficiency and continuous improvement, all of which are important benefits to rate payers. NiSource applies a "total rewards" compensation philosophy which is used to attract, retain and motivate qualified employees. A key component of the "total rewards" structure is variable pay. The incentive plan is designed to drive and reinforce goals in employees' performance

management worksheets. In conclusion, incentive pay provides reinforcement for the PMW process which incorporates customer benefitting objectives. Furthermore, the inclusion of variable compensation aligns Columbia and NCSC with 92% of employers who utilize variable compensation. To retain, reward, and motivate employees, the Company believes incentive compensation is an important element of a well-designed, competitive compensation package.

Q. Do you agree with Ms. Wilson's and Mr. Catlin's proposal to disallow the company's entire claim for Profit sharing?

A. No, I believe the Profit Sharing plan, as an element of the company's Retirement Savings Plan, supports employees' saving for retirement. Company contributions for Profit Sharing are deposited into employees' Retirement Savings Plan accounts providing an important element of employee savings. These contributions to the Savings Plan have become even more important as more traditional elements of retirement savings, including defined benefit plans, are no longer offered to exempt new hires on or after January 1, 2010 and nonexempt new hires on or after January 1, 2013. As an element of a balanced competitive benefits program, profit sharing contributions into the Retirement Savings Plan should be allowed.

Q. Do you agree with Ms. Wilson's proposal to disallow the Company and NCSC's entire claim for stock awards and Mr. Catlin's proposal to disallow the Company's claim for Phantom Stock?

A. No. Stock awards are a common element of compensation at certain levels of organizations throughout the U.S. and as such the costs should be allowed. These

stock awards allow NiSource to attract and retain individuals at executive levels which would be difficult to accomplish without this element of compensation. In addition, Phantom Stock is an element of retention for a small number of key executives. This competitive requirement is seen clearly in the following excerpt from the Aon Hewitt survey "U.S. Total Compensation Measurement (TCM) - Executive Compensation Policies and Programs U.S. Edition" September 2011, which included participation by 417 companies.

> Of these 417 companies, 89% reported at least one form of long-term incentive. Topics covered for each long-term incentive plan include eligibility, grant frequency, range of award opportunity, exercise restrictions, form and timing of payment, and treatment of dividends.
>
> For those companies reporting a long-term incentive plan, 79% have two or more vehicles in 2011 compared to 81% in 2010. Three or more plans were reported by 48% of the companies this year.

With 89% of companies surveyed providing at least one form of long-term (generally stock) incentive, the Company and NCSC would be at a major disadvantage in attracting new executives or retaining current leaders without the ability to also provide such forms of compensation. Retaining key leaders and attracting new talented individuals is critical and therefore, offering stock based programs is an appropriate cost of doing business.

Q. Does this complete your Prepared Rebuttal Testimony?

A. Yes.

COLUMBIA STATEMENT NO. 121-R

2-13-13
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BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
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	)	
	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

DEBORAH A. DAVIS

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name, and business address.

A. Deborah Davis, 121 Champion Way, Suite 100 Canonsburg, PA 15317

Q. By whom are you employed and in what capacity?

A. I am employed by Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company") as Manager, Universal Services.

Q. What are your responsibilities as Manager, Universal Services?

A. I am responsible for efficient and compliant administration of all programs for low income customers including the Customer Assistance Program ("CAP"), the Low Income Usage Reduction Program ("LIURP"), and the Low Income Home Energy Assistance Program ("LIHEAP").

Q. What is your educational and professional background?

A. I hold a Bachelor of Arts degree in Social Work from the University of Pittsburgh. Prior to joining Columbia in 1992, I worked at a community based agency assisting low income clients with accessing utility service and providing other basic life necessities. I was hired as a Community Relations representative and subsequently became Manager of the Customer Programs department. My titles have changed over the years but I have remained in a similar function throughout my 20 year career at Columbia.

Q. Did you submit Direct Testimony in this matter.

A. No, I did not.

Q. What is the purpose of your Rebuttal Testimony?

A. I will address issues raised by Community Action Association of Pennsylvania ("CAAP") witness Susan A. Moore-Wychulis and Coalition for Affordable Utility

Services and Energy Efficiency in Pennsylvania ("CAUSE-PA") witness Eugene M. Brady in their Direct Testimony. Ms. Moore-Wychulis and Mr. Brady both propose that the Commission direct Columbia to increase its LIURP budget.

Q. Does Columbia support increasing the LIURP budget?

A. No. Columbia just increased the LIURP budget from $3,000,000 to $4,000,000 for the 2012 program year. Currently Columbia has the second highest LIURP budget for gas utilities in the state. In 2012, Columbia was projected to spend more than all of the other three gas utilities combined in Western PA on LIURP.

Q. Is Columbia's current LIURP budget too low to address the needs of LIURP-eligible customers?

A. No. Columbia's needs assessment provides a snapshot of current eligible customers based on self-declared income and the last heating season's usage. It does not take into account any customers who previously received weatherization measures through LIURP or who were removed from the program due to structural issues such as the presence of knob and tube wiring or mold, or failure to cooperate with program requirements. In Columbia's most recent needs assessment from 2011, Columbia identified 21,290 customers that met the income and consumption requirements at that time, which amounted to a decrease of 15,000 from the prior needs assessment conducted in 2007.

Q. Does Columbia concur with Mr. Brady's position that, at the current funding level of $4 million, it will take too long to meet the needs of these 21,290 customers?

A. No. In 2012, Columbia prescreened 1,900 accounts to complete 517 homes. If usage by the remaining 1,300 accounts continues to be high, they will remain part

of the needs assessment, even though we were not able to provide weatherization services to them through the program. In reviewing current records, which reflect the 2011/2012 heating season usage, Columbia found 1306 property owners and 1714 rental units that meet the LIURP guidelines that have not been completed/rejected or cancelled in the LIURP program to date. This is a snapshot in time and will change as usage changes. Columbia will most likely reach out to half of these customers this year for LIURP participation.

Q. Are there any other reasons why Columbia should not increase its LIURP budget at this time?

A. Yes, as I noted above Columbia just increased its LIURP budget by $1,000,000. This was a sizeable increase and necessitated increased contractor production levels and the retention of new contractors. Although the increased funding provides the opportunity to provide additional services, increased funding also provides challenges. To manage these challenges, Columbia implemented a new and more comprehensive quality assurance program to insure program integrity during the expansion of the program. Columbia believes that another full year at $4,000,000 will allow the company to work out any additional implementation issues and solidify existing and new contractor relationships. This approach will help to insure service level quality and customer service continuity. For these reasons, Columbia does not support the increased LIURP funding proposals offered by CAUSE-PA or CAAP. However, the Company will continue to evaluate the operations of LIURP and, to the extent necessary, will recommend changes in the company's next USECP.

Q. Does the company continue to support its proposal to include $50,000 in the Rider USP to help fund PA 2-1-1?

A. Yes. However, if the $50,000 for PA 2-1-1 is not approved, Columbia does not agree that it should be added to the LIURP budget for reasons already expressed.

Q. Does Columbia agree with partnering with electric distribution companies as suggested by CAUSE-PA?

A. Yes. Columbia currently refers eligible customers to Duquesne Light, First Energy and West Penn Power LIURP programs. In addition, several contractors cross check their electric customers with our LIURP lists before either audit. Columbia recognizes the value of these partnerships including improved customer satisfaction and increased customer benefits. Columbia intends to solidify and enhance these current efforts in 2013.

Q. Are there any other issues you would like to address?

A. Yes, Mr. Brady, representing CAUSE-PA pointed out some recommendations made by a third party evaluator related to CAP removal rates. That evaluation was conducted in 2010. Since that time, Columbia has implemented many of the recommendations, including: redesigning the initial verification letter, additional phone attempts by Dollar Energy Fund (DEF) staff and cross checking of income verification with other programs, including DEF hardship fund and electric utility CAP's administered by DEF.

Q. Does Columbia feel they have addressed the issue and resolved the recertification removal concern?

A. Reverification rates dropped in 2010 and 2011 presumably as a result of the implementation of these recommendations. Columbia continues to look for new ways to increase income reverification rates. We agree with CAUSE-PA's recommendation to pursue additional channels to improve income verification rates and expect to increase efforts in 2013.

Q. Is there anything else within testimony that you would like to comment on at this time?

A. Yes. I would like to comment on Ms. Maurer's testimony regarding Columbia's WarmWise-Audits & Rebates program (WW A&R). Specifically, on page 8 of Ms. Maurer's testimony, it states that she does not disagree entirely with Columbia's proposal to make changes to the WW A&R program design without seeking Commission approval for each change with the condition that Columbia will not exceed the current funding of $750,000 and continues to state that the income eligibility should remain at the level of 151%-250 of the Federal Poverty Guideline.

Q. What does Columbia want to say in response to this statement?

A. Columbia appreciates Ms. Maurer's consideration that some changes should be permitted without Commission approval and notes her concern regarding income eligibility. Columbia is not proposing to make changes to the income eligibility guidelines at this time and would first seek Commission preapproval to do so in the future.

Q. Is there anything else that you would to rebut regarding Ms. Maurer's testimony?

A. Yes. I would like to comment on Ms. Maurer's testimony regarding the WW A&R

funding level. Specifically, on page 9 of Ms. Maurer's testimony, she recommends that Columbia's funding level budget for WW-A&R be reduced from $750,000 to $200,000.

Q. Do you agree with this recommendation?

A. No. Columbia does not agree with a reduction in funding for this program for several reasons. First, Ms. Maurer quotes the average spending level of $160,800 for the program for the first three years. This is not a fair indication of the funding requirement of the program.

Q. Would you please explain why the average spend level for the first three years does not represent the needed funding requirements of the program.

A. Yes, first, the $160,800 average three year spend does not include the spending for the most recent year (2012), which was approximately $435,000 and indicates an upward trend and progressive increase in program participation. Second, it is important to realize that this $750,000 was not included as part of the Company's requested revenue increase. The $750,000 is an upper limit of what the Company can invest in Audits and Rebates for eligible customers. If the customers do not participate and the Company does not make any investments in any given year, the annual expenses are not included in Rider USP and they are therefore not charged to those customers who pay Rider USP. Awareness of the program is growing as a result of the Company's increased outreach and promotional efforts. Consequently, lowering the annual budget would not serve any valid purpose and it would only deny eligible customers the opportunity to participate in a program that will save them energy and lower their future gas

bills. Third, niche programs like this in general require a considerable amount of time for start-up before full implementation and a full run rate is realized. Several key factors to implementation are the development of the contractor network, program procedures and outreach/marketing. Columbia made changes within the first two years of the program which contributed to the quality of the program. The Company continues to monitor the program and make modifications to design elements and fine tune procedures, as part of the start-up mode, to ensure a successful energy efficiency program. Lastly, Columbia has recently increased its outreach and marketing efforts to build awareness of the program. This takes time and repetitive messaging for customers to become aware of the program and then decide to participate. The average spending level that Ms. Maurer reported does not take into consideration the anticipated impact on participation as a result of outreach messaging.

Q. Can you further explain some of the changes that were made to fine tune the program?

A. Yes, Columbia originally offered a walk-through education audit without rebates as part of the original program design. The cost of the measures was totally borne by the customer. Columbia soon realized that customers who could not easily afford the cost of the retrofits were not likely to participate in the audit either. Columbia, with Commission approval, offered modest incentives for installed measures. To coincide with this change, Columbia upgraded the audit to a Building Performance Institute (BPI) certified audit which included diagnostic appliance safety checks to ensure safe air quality and a technical analysis of

recommended energy efficiency measures. The change required the Company to acquire and establish contracts with additional certified BPI audit organizations and provide training.

Q. Were there any other modifications to the program that Columbia made over the past three years?

A. Yes, after a year of implementing the rebates, Columbia recognized that the incentives originally recommended were too low to encourage participation. The costs of the measures were still more than the customer could afford. Columbia also learned while observing the PA State Appliance Rebate Program, funded through the American Recovery and Reinvestment and Act (ARRA) that their originally established rebate levels were set too low and did not attract participation. However, once raised, the PA State Appliance Rebate Program exhausted its funding within several months. In 2012, Columbia sought and obtained Commission approval to raise the WW A & R rebate amounts. Since the change in rebate levels, Columbia has seen a significant increase not only in audits but also in the completed measures (150% and 300% increases respectively).

Q. Can you explain how the current approval process has affected implementing these specific changes to the program?

A. Yes. Columbia appreciates the Commission's dedication and attention to providing the necessary guidance regarding the approval of the needed changes to the program. However the time lag that sometimes occurs can limit the Company's ability to implement the changes quickly in order to increase

participation and thereby loses time and enrollment opportunities. This is why Columbia requests that the Company be granted the flexibility to make necessary improvements to the program without Commission approval while maintaining the current level of funding.

Q. What other reasons can Columbia provide for disagreeing with the recommendation to reduce the program funding?

A. Columbia recognizes that outreach and marketing are necessary to build awareness and to promote the benefits of the program to its customer. The WarmWise Audits & Rebates program is a program targeted towards the working poor and relies solely on the customer's decision to choose to participate. Although the audit is free and there are incentives provided, there are remaining expenses for the installation of the recommended measures that are the responsibility of the customer. These issues factor into the customer's decision to participate. Moving the market to understand the benefits of the program and then participate requires time, effort, a strategic outreach plan and funding. Reducing the funding would further impair the program's opportunity to succeed by limiting the ability to promote the program externally effectively.

Q. Can Columbia share any other reasons why the funding level should not be reduced?

A. Yes. The Company records and demographics support a funding level of $750,000. Columbia has identified approximately 53,000 Columbia Gas customers who fall within the demographic income guidelines. For comparison purposes, Columbia has identified 3020 customers who currently qualify for

WarmWise-LIURP and that program has a guaranteed annual funding level of $4,000,000 – more than four times the budget limit for WWA & R. We have only begun to address the potential need. Program awareness and outreach are key to tapping into this customer segment. Columbia has partnered with other state and local pilot programs, such as ARRA funded Fayette County Better Buildings Initiative, to broaden awareness and leverage additional funding and benefits for customers, making the completed measures more realistic. Columbia is embarking on a similar partnership with the Pennsylvania Home Financing Agency and the Allegheny County Department of Economic Development to promote program participation and create additional energy efforts. Program partnerships such as the two mentioned require the commitment of funding and outreach from Columbia to sustain pilot success. Lastly, Columbia appreciates and supports the network of companies and organizations that contract with Columbia to perform the audits and install the measures. To reduce funding would affect the contractors' business models which include revenue from this program. With the expiration of the ARRA funding last year, the energy efficiency industry, including the audit companies, weatherization and HVAC contractors, have already realized a shortage in funding. To reduce the WWA&R funding would further impact their employment opportunities.

Q. Is there any additional testimony pertaining to the WarmWise Audits & Rebates program that you would like to rebut at this time?

A. Yes. I would like to respond to Mr. Brady's testimony, on Page 16, where he states that although he agrees that Columbia should have some flexibility in managing

its program, he states that Columbia should not be permitted to offer an On Bill Financing program without Commission approval and stakeholder input.

Q. Do you agree with his statement?

A. No, Columbia does not agree with this statement. Columbia confirms its original position that it should be granted the flexibility to make modifications to the program without Commission preapproval provided that it does not exceed the original annual funding level of $750,000. This should include the flexibility to offer an On Bill Financing/On Bill Repayment (OBF/OBR) program should it be in the best interest of the customer and company.

Q. Does Mr. Brady offer reasons as to why Columbia should have Commission approval before making this sort of modification to the program?

A. Yes, Mr. Brady states that there are many questions and issues surrounding OBF/OBR programs that would need to be addressed prior to the implementation of such a program component, even at a pilot stage.

Q. Does Columbia agree with this statement?

A. While Columbia agrees and is fully aware that there are many details and issues to resolve within the design of OBF/OBR programs, Columbia disagrees with Mr. Brady's statement and further believes that it should not be required to seek Commission preapproval prior to implementation. Columbia is aware that the concept of OBF/OBR is currently being discussed as part of the Act 129 Phase II proceedings and that, per a Commission Order, the PUC has convened a stakeholder group to discuss the feasibility of such a utility program. Columbia is currently a participant within this stakeholder group and would take into

consideration the input from the discussions and findings prior to implementing an OBR pilot as part of its WW A&R program.

Q. Are there any other reasons why Columbia believes that it should be granted flexibility to offer an OBF/OBR component as part of the program without Commission preapproval?

A. Yes. It is important to the success of the program and the customers which it serves, to be in a position to move quickly when opportunities are presented that would allow for even further enhancements and customer benefits. Should Columbia be provided an opportunity to partner with a third party organization that could offer the necessary resources to implement an OBF/OBR component, Columbia would like to be able to respond timely so to seize the opportunity, provided that it is in the best interest of the customer and company. The potential lag of the approval process could jeopardize the program's ability to succeed in providing quality customer services and benefits.

Q. Does Columbia have anything else to add regarding this part of your rebuttal testimony?

A. Yes. In conclusion, Columbia has worked closely with its contracting partners to identify program improvements for ways to increase participation, customer satisfaction and safety. With each change, Columbia has increased the quality of the program overall with corresponding increases in participation. Columbia requests that it be granted the flexibility to make necessary program modifications, without preapproval from the Commission, while not exceeding the established annual funding level. In addition, Columbia requests that the

funding level for its WWA&R not be reduced and remain at the current fully reconcilable annual amount of $750,000. A reduction in funding to any level while the program is ramping up could be detrimental to the program, customers and contractors.

Q. Does that conclude your Rebuttal Testimony?

A. Yes, it does.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	:	Docket Nos. R-2012-2321748
	:	M-2012-2323645
Office of Consumer Advocate	:	C-2012-2330240
Office of Small Business Advocate		C-2012-2330539
Anastasia Stratigos	:	C-2012-2330724
Louis and Joanne Quahliero	:	C-2012-2332087
Angela Burnett	:	C-2012-2332497
G. Thomas Smeltzer	:	C-2012-2333247
Michelle Swartz	:	C-2012-2328788
Columbia Industrial Intervenors	:	C-2012-2334026
Johanna Shigle	:	C-2012-2336033
	:	
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Deborah A. Davis, being Manager, Universal Services of Columbia Gas of Pennsylvania, Inc. ("Columbia"), hereby state that the testimony set forth in Columbia Statement No. 121-R are true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013

Deborah A. Davis

COLUMBIA STATEMENT NO. 122-R

2-13-13
Hbg

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
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	)	
vs.	)	Docket No. R-2012-2321748
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

REBUTTAL TESTIMONY OF

SCOTT D. PHELPS

ON BEHALF OF

COLUMBIA GAS OF PENNSYLVANIA, INC.

January 28, 2013

Q. Please state your name and business address.

A. Scott D. Phelps, 200 Civic Center Drive, Columbus, Ohio 43215.

Q. Who are you employed by?

A. I am employed by NiSource Corporate Services Company, providing service to Columbia Gas of Pennsylvania, Inc. (Columbia).

Q. What is your position?

A. My job title is Director, Large Customer Relations.

Q. Please describe your educational background and your employment history with Columbia.

A. I received my higher education at Michigan Technological University, and earned my Bachelor's Degree in Civil Engineering while there. In 1978, I joined Columbia Gas of Ohio, Inc. as an Industrial Marketing Engineer and was responsible for representing Columbia Gas of Ohio to its industrial and large commercial customers throughout Southeastern Ohio. In 1984, I became the Manager, Gas Transportation in Columbia's Marketing Department in Columbus, serving that function for all of the Columbia gas distribution companies, including Columbia Gas of Pennsylvania. While in that role, I was responsible for developing on system gas transportation services for industrial and commercial customers. In 1989, I was promoted to Director, Gas Procurement and had responsibilities related to the contracting, acquisition, scheduling, and payment for gas supplies, as well as contract administration and capacity release, and for a time, the on-system gas transportation customer nomination process. Again, my responsibilities related to this role included all of the Columbia gas distribution

companies. In 2010, I became the Director, Large Customer Relations, which is the job I hold at this time. My current role involves directing the management of the largest industrial and commercial customer accounts for all of the Columbia gas distribution companies, including Columbia Gas of Pennsylvania. This includes providing these customers with the service and assistance they may require when dealing with natural gas, the negotiation of contract terms in some instances, and directing the management of projects related to attaching large new customers to the system.

Q. Have you testified previously before this or any other Commission?

A. Yes, I've testified before this Commission on more than one occasion with regard to Columbia's 1307(f) cases, and also before Commissions in Ohio, Kentucky, Virginia, and Maryland.

Q. What is the purpose of your rebuttal testimony?

A. I will respond to the testimony of OSBA witness Knecht with regard to flex rates.

Q. Which of Columbia's flex rate contracts does Mr. Knecht address in his testimony?

A. Witness Knecht focuses his comments and recommendation on the LDS class of customers in his response, due to very low percentage of volumes subject to flex rates to customers under rate schedules other than LDS. He further narrows his focus to only those LDS flex rate customers that have a flex contract that results from the customer having a choice of NGDCs from which to take service.

Q. What other types of LDS flex customers are there, and why has witness Knecht excluded them from his focus and recommendations?

A. Flex contracts are also in place between Columbia and LDS customers that could elect to take service from interstate natural gas pipeline companies, and customers that could choose another competitively priced fuel, other than natural gas, such as coal, oil, propane, or wood, to meet their energy needs.

Q. What is the reason witness Knecht provides for excluding these types of contracts from his focus and recommendation?

A. Witness Knecht testifies that he simply accepts Columbia's claim that rates cannot be raised to those customers, and that any perceived revenue shortfall associated with charging flexed rates to those customers should be reasonably shared among Columbia's other rate classes.

Q. What are witness Knecht's recommendations regarding flexed rate contracts that Columbia currently has in place with LDS customers who could readily switch to a competing NGDC?

A. Witness Knecht's recommendation is to "move these customers to tariff rates". Further, he suggests that the Commission not include a revenue shortfall for such contracts in Columbia's current rate proceeding. Witness Knecht also asks the Commission to "not allow" any other NGDC to offer any of those specific customers a flex rate. Moreover, he suggests that Columbia could continue to flex its rates as long as Columbia was not allowed to recover the shortfall in its rate cases. Finally, witness Knecht testifies that although the Commission has initiated an Investigation on Gas-On-Gas Competition Between Jurisdictional Natural Gas Distribution Companies, his recommendations should be approved and implemented now regardless of that proceeding.

Q. Does Columbia agree with the recommendations?

A. Absolutely not. Mr. Knecht's recommendations attempt to arrive at a short cut answer to an issue that has developed over time as the NGDCs in the area grew throughout the last century. Furthermore, he would like everyone to agree with his solution before the real conversation has begun. In its last base rate case, Columbia was asked, and agreed through a settlement, to support the initiation of a generic proceeding on the topic of NGDC on NGDC competition as that pertains to flexed rates. In response to a Joint Petition in which OSBA collaborated as a joint petitioner, the Commission has undertaken a broad investigation regarding NGDC on NGDC competition in which all interested parties are participating (Docket No. I-2012-2320323). This by itself should be enough reason for the Commission to deny OSBA's request at this time.

But there is more reason than that. This issue has been a long standing one (Mr. Knecht quotes his own testimony from a 1995 case when he made essentially the same arguments). The Western Pennsylvania NGDC on NGDC competitive flex rate issue is long standing because it is complex and because there are strong counter points to witness Knecht's opinion. About forty percent of Columbia's total customer base has access to another NGDC. The matter is not going to be easy to resolve due to the large investments made in those pipes by Columbia and other NGDCs and the fact that these overlapping service territories preceded regulation. This issue cannot be resolved in a proceeding involving any one NGDC nor should it be resolved by directing a single NGDC to assume the difference in revenues between flexed rates and full tariffed rates. As long as

there are customers in search of lower distribution rates and as long as NGDCs have base rate proceedings, the parties will continue to deal with the question of how to allocate the costs remaining after customers have left the system. It is for these reasons that Columbia has indicated its willingness to participate in a generic investigation involving the stakeholders to this issue. Since the current Gas-On-Gas investigation is intended to hear everyone's views on the issue, it is certainly premature to implement changes in policy at this time, in this case.

Q. Do you agree with witness Knecht's suggestion that Columbia can continue to flex rates if it wants to but that Columbia should absorb the flexed revenue as opposed to recovering it from its rate base?

A. No, I do not agree. Columbia has specific and clear rights under its approved tariff to enter into a flexed rate contract with a customer when such a lower rate is needed to "meet competition from an alternate fuel." When a customer is able to demonstrate an ability to leave Columbia's distribution system by switching to service from another NGDC, Columbia is able, pursuant to its tariff rules, to compete for that customer's business by flexing its rate which, if successful, allows Columbia to receive payments from that customer to be applied toward Columbia's rate base. The Commission should not expect Columbia to continue to flex its rates under a rate policy that does not offer Columbia an opportunity to recover its costs of service. It is critical to understand that Columbia's costs of distribution service are fixed and therefore, it is not in Columbia's interest to serve a customer at a flexed rate if it means that Columbia will absorb a portion of fixed costs for every flexed charge.

Q. Mr. Knecht appears to propose some protection for Columbia by recommending that the Commission "not allow any other NGDC to offer any of those specific customers a below full-tariff rate". "Specific customers" in this case, presumably refers to Columbia's customers that have flexed rates due to NGDC on NGDC competition. Is this a satisfactory solution?

A. No, it is not. First, I am advised by counsel that there is a substantial issue concerning the Commission's authority to order other NGDCs to refrain from offering flexed rates that are permitted by their tariffs in the context of a case in which they are not a party. Second, the recommendation does not deal with a brand new customer that could select either Columbia or another NGDC as their supplier. This customer is not "specific" under OSBA's recommendation, so one of the NGDCs, Columbia, would only be able to offer a tariff rate, while the other competing NGDC could offer a flexed rate. Third, Mr. Knecht does not address those customers that are currently served by Columbia at full tariff rates that are approached by an NGDC with the offer of a flexed rate. They are not "specific customers" under Mr. Knecht's recommendation either, and once again, Columbia would be at a competitive disadvantage.

Q. Why should an NGDC in Western Pennsylvania flex rates when competing with another NGDC with pipe in proximity to the customer?

A. Customers have many forms of competitive alternatives to taking distribution service from Columbia. Columbia's flex rates are negotiated by conducting an investigation of the particular facts surrounding the customer's competitive alternative to Columbia's service. Regardless of the particular customer's

situation, the final decision regarding whether and how much to flex a rate is based on whether the criteria as a whole prove that the customer has a viable alternative to Columbia's service and what the minimum amount of discount is needed to retain the customer on its distribution system. Contrary to witness Knecht's opinion, for this decision, it simply does not matter whether the alternative fuel is oil, an interstate pipeline or if the alternative is another NGDC. If the Company does not flex its rates, the customer will leave Columbia's distribution system and it simply does not matter whether the customer moves to oil, an interstate pipeline, or another NGDC.

Q. Is it important for Columbia to identify the least amount of discount needed to retain the customer on its distribution system?

A. Yes, it is. This is because between rate cases, the Company absorbs all discounts that are above the amount that was included in the Company's last base rate case, and because it is important to the Company to provide the lowest rates it can to its customers that pay the tariff rate. In addition, when the Company discounts a rate, the contract can be subject to challenge within a rate case if the discount was not justified. Because of these facts, the Company has strong incentive to discount its rates only to the degree necessary to retain the customer. This incentive is strong enough that Columbia has, on occasion, lost customers to other NGDCs because Columbia's offer was not low enough to retain the customer.

Q. Why is it a problem if the customer leaves the system?

A. When a customer leaves the distribution system, little to no costs are avoided.

Thus, Columbia's revenue requirement remains essentially unchanged, and the revenue previously received from those customers is recovered from all remaining customers when the company's total cost of service is reallocated to its remaining rate classes through its cost of service study in its next base rate case. Unnecessarily increasing rates to remaining customers in this way would eventually cause Columbia's rates to increase to the point where another customer found it advantageous to leave the system, placing additional upward pressure on Columbia's rates which, in turn, could cause even more customers to leave the system, and so on. The result of such a trend is that not having the ability to flex rates would ultimately drive up all of Columbia's rates.

Q. Even if the Commission, in a proper proceeding, decided that all NGDCs could not flex their rates in competition with other NGDCs, does that mean that Columbia would retain at full tariff rates all customers who currently receive flex rates because of NGDC competition?

A. No. If the Commission were to prohibit flexing for all NGDCs to meet NGDC competition, these customers would continue to seek out the lowest cost alternative. Thus, customers would swing to the NGDC with the lowest current rate. Customers thus could potentially move back and forth among NGDCs as rates change between rate cases. These customers would also be expected to investigate other alternatives, such as interstate bypass, local gas bypass and alternative fuel bypass.

Q. Do you have any other comments about Mr. Knecht's proposal to require Columbia to absorb the difference between tariff rates and flex rate?

A. Yes. Such a proposal assumes that the tariff rate is based on real cost of serving the customer. While I am not a cost of service expert, it is my understanding that many assumptions and judgments go into assigning costs to a class of customers and there are many disagreements about such allocations. Clearly, if the tariff rate is above the cost of serving the customer, then this difference between the flexed rate and tariff rate cannot be a subsidy.

Q. Does this conclude your rebuttal testimony?

A. Yes.

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

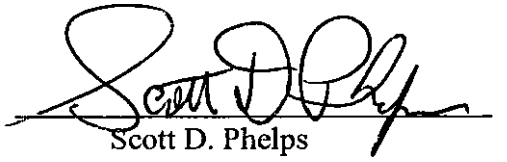
Pennsylvania Public Utility Commission	:	Docket Nos. R-2012-2321748
	:	M-2012-2323645
Office of Consumer Advocate	:	C-2012-2330240
Office of Small Business Advocate		C-2012-2330539
Anastasia Stratigos	:	C-2012-2330724
Louis and Joanne Quahliero	:	C-2012-2332087
Angela Burnett	:	C-2012-2332497
G. Thomas Smeltzer	:	C-2012-2333247
Michelle Swartz	:	C-2012-2328788
Columbia Industrial Intervenors	:	C-2012-2334026
Johanna Shigle	:	C-2012-2336033
	:	
v.	:	
	:	
Columbia Gas of Pennsylvania, Inc.	:	

VERIFICATION

I, Scott D. Phelps, being Director, Large Customer Relations of NiSource Corporate Services Company ("NiSource"), hereby state that the testimony set forth in Columbia Statement No. 122-R is true and correct to the best of my knowledge, information and belief, and that if asked orally at a hearing in this matter, my answers would be as set forth herein.

I understand that the statements herein are made subject to the penalties of 18 Pa.C.S. § 4904 relating to unsworn falsification to authorities.

Date: February 11, 2013



Scott D. Phelps