Columbia Gas of Pennsylvania, Inc.
2016 General Rate Case
Docket No. R-2016-2529660
Standard Filing Requirements
Testimony - All
Volume 10 of 10

COLUMBIA STATEMENT NO. 1

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
vs.	)	Docket No. R-2016-2529660
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
MARK KEMPIC
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

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I. INTRODUCTION

Q. Please state your name and business address.

A. Mark Kempic, 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 its President.

Q. What are your responsibilities as Columbia's President?

A. I am the corporate officer responsible for the leadership of Columbia Gas of Pennsylvania, Inc. and its various departments, including Rates and Regulatory Policy, Governmental Affairs, Communications and Community Relations.

Q. What is your educational and professional background?

A. I hold an Associate Engineering Degree in Solar Heating and Cooling Technology from the Pennsylvania State University, a Bachelor's of Science Degree in Computer Science from the University of Pittsburgh and a Juris Doctor from the Capital University Law School in Columbus, Ohio. I held various positions within Columbia and its parent company from 1979 through 1992 including emergency service dispatcher, engineering technician, information systems analyst, gas supply and corporate planning analyst. From 1992 through 1994, I worked at a law firm where I represented the interests of industrial customers in utility regulatory proceedings before the Public Utilities Commission of Ohio and from 1994 until my return to Columbia, I worked as in-house state regulatory counsel for an electric company in Cleveland, Ohio. After rejoining Columbia in 1998, I initially served as an attorney and was subsequently promoted to senior attorney and then assistant general counsel. In October of 2009, I was named Director of Rates and Regulatory Policy for Columbia. I assumed my current responsibilities when I was named President in June 2012.

Q. Have you ever testified before a regulatory Commission?

A. Yes, I have testified before both the Pennsylvania Public Utility Commission ("Commission") as well as the Maryland Public Service Commission. Most recently, I testified in Columbia's last five base rate cases before the Commission at Docket Nos. R-2009-2149262, R-2010-2215623, R-2012-2321748, R-2014-2406274 and R-2015-2468056.

Q. Please describe the scope of your testimony in this proceeding.

A. Through my testimony, I will provide the Commission with an overview of this base rate filing, discuss the objectives that Columbia seeks to accomplish in this proceeding and discuss the Company's progress since the last rate proceeding. I will also address Columbia's quality of service in compliance with Section 523 of the Public Utility Code, and I will introduce Columbia's other witnesses who provide detailed testimony and supporting documentation for all revenues, expenses and rate base elements included in the fully forecasted rate year in this base rate filing.

Q. Please describe briefly the corporate history of Columbia and its relationship with its parent company, NiSource Inc. ("NiSource").

A. Columbia was incorporated on June 23, 1960 as a wholly-owned subsidiary of the Columbia Gas System, Inc., under the Act of May 29, 1885, P.L. 29 of the Commonwealth of Pennsylvania and commenced service as Columbia Gas of Pennsylvania, Inc., on January 1, 1962, when it acquired the Pennsylvania retail business of The Manufacturers Light and Heat Company, which was at that time another wholly-owned subsidiary of The Columbia Gas System, Inc. In 1998, the Columbia Gas System, Inc. became the Columbia Energy Group ("CEG"). In turn, CEG merged with NiSource in 2000, at which time Columbia became one of ten (10) natural gas distribution companies in the NiSource corporate family as it existed at that time. Columbia is engaged in the business of furnishing natural gas service to approximately 421,000 residential, commercial, and industrial customers pursuant to certificates of public convenience and necessity issued by the Commission. Columbia has its principal office in Canonsburg, Pennsylvania and provides natural gas distribution service in portions of 26 counties in Pennsylvania, primarily in the western half of the state, as well as parts of Northwest, Southern and Central Pennsylvania.

NiSource, headquartered in Merrillville, Indiana, is an energy holding company whose subsidiaries provide natural gas and electricity distribution services to approximately 3.9 million customers located within a corridor that runs from the

Midwest to New England. NiSource is the successor to an Indiana corporation organized in 1987 under the name of NIPSCO Industries, Inc., which changed its name to NiSource Inc. on April 14, 1999. In connection with the acquisition of CEG on November 1, 2000, NiSource became a Delaware corporation registered under the Public Utility Holding Company Act of 1935 (now known as the Public Utility Holding Company Act of 2005).

In September 2014, NiSource announced a major strategic initiative designed to better position its business. Specifically, the separation which took effect July 1, 2015, resulted in two highly focused, premier energy infrastructure companies – a fully regulated natural gas and electric utilities company (NiSource) and a natural gas pipeline, midstream and storage company (Columbia Pipeline Group). Post-separation, NiSource maintains significant scale and remains one of the largest natural gas utility companies in the United States, serving more than 3.4 million customers in seven states under the Columbia Gas and NIPSCO brands. NiSource has maintained strong levels of customer focus, local employment, community involvement, and commitments made to Pennsylvania. Safe, reliable, and efficient service remains the top priority.

In June 2015, NiSource received confirmation of its post-separation investment-grade credit ratings. Standard & Poor's upgraded NiSource's credit rating to BBB+ from BBB-, Fitch Ratings revised its outlook on NiSource to BBB- (positive) from BBB- (stable), and Moody's reaffirmed its rating of NiSource at Baa2.

On September 15, 2015, NiSource was named to the Dow Jones Sustainability Index ("DJSI") North America in recognition of the Company's sustainable business practices and performance for the second consecutive year. The DJSI North America Index and respective subsets track the performance of the top 20 percent of the 600 largest Canadian and United States companies in the S&P Global Broad Market Index. In the Multi and Water Utilities category, fourteen North American companies were evaluated and four were selected. Since its launch in 1999, NiSource has been named to the DJSI nine times.

In addition, on March 7, 2016, NiSource was designated as one of the World's Most Ethical Companies by the Ethisphere Institute. NiSource is the only Company in this year's gas utility category. According to Ethisphere, the World's Most Ethical Companies designation recognizes companies that work tirelessly to make trust part of their corporate DNA and, in doing so, shape future industry standards by introducing tomorrow's best practices today. This is the fifth consecutive year that NiSource has been recognized by the Ethisphere Institute.

NiSource remains subject to the jurisdiction of the Securities and Exchange Commission and is traded on the New York Stock Exchange with the symbol "NI". The NiSource gas distribution companies are: Northern Indiana Public Service Company ("NIPSCO"), Bay State Gas Company d/b/a Columbia Gas of Massachusetts, Columbia Gas of Kentucky, Columbia Gas of Maryland, Columbia Gas of Ohio, Columbia Gas of Pennsylvania, and Columbia Gas of Virginia.

II. CASE OBJECTIVES

Q. Please summarize Columbia's major objectives in this proceeding.

A. Columbia seeks Commission approval to increase its base rates to recover the revenue requirement associated with the capital Columbia has invested, and will continue to invest, in its facilities as part of its accelerated pipeline replacement program. Approval of the Company's request is necessary for Columbia to continue to provide safe and reliable natural gas service at the lowest reasonable price to its customers while providing the Company with a reasonable opportunity to recover its costs and to earn a fair rate of return. Further, approval of this request will demonstrate to the investment community that the Commission continues to support the need for intensified focus on pipeline safety matters as well as the need for reasonable and predictable earnings. My testimony will outline, at a high level, the objectives of Columbia's filing. Details and documentation supporting each of the objectives will be provided by Company witnesses that I will introduce later in my testimony.

a. Proposed Rate Increase

Q. Will you please explain Columbia's objective by filing this case?

A. Columbia seeks recovery of, and an opportunity to earn a return on, the capital investments being made in its distribution system which are necessary to provide safe and reliable natural gas distribution service to its customers. In light of the substantial capital investment Columbia has made since its last rate case and the large capital investments that will be made through the end of 2017, Columbia is filing this base rate case using the fully projected future rate year contemplated by 66 Pa. C.S. § 315 ("Act 11") in order to provide itself with a reasonable opportunity to recover its investment in its distribution system and its operation and maintenance ("O&M") expenditures.

Q. Why is Columbia filing a base rate case instead of using the Distribution System Improvement Charge ("DSIC")?

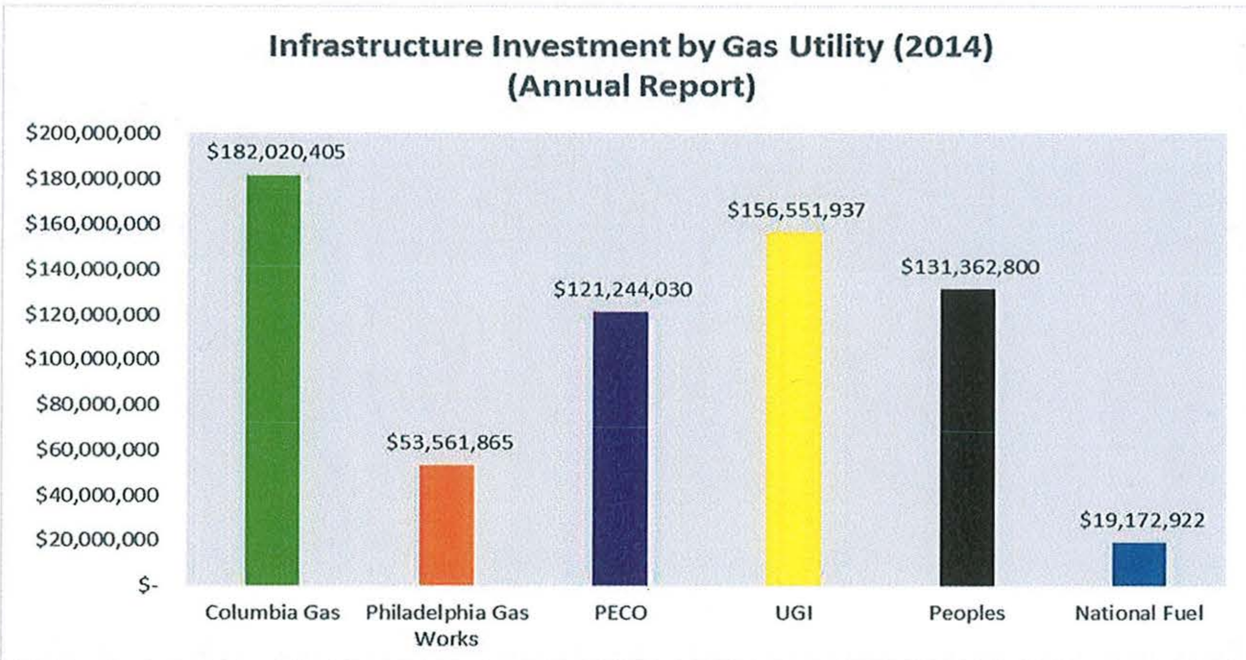
A. Columbia's revenue deficiency is driven by both the large capital investment that it continues to make in modernizing its distribution system as well as increases in O&M expenditures over and above the level built into current rates. Due to the scale of Columbia's investments in replacement pipe, Columbia's requested overall distribution (i.e. exclusive of gas costs) revenue increase in this case is approximately 16.16%, which exceeds the current 5% cap on DSIC surcharges. In addition, the DSIC does not permit recovery of O&M costs. Thus, even if the 5% DSIC cap were increased, a rate case would be needed to recover the increases in O&M costs.

Q. What is Columbia's proposed rate increase in the case and what are some of the primary drivers for the increase?

A. Based on the rates established in Columbia's last rate case and Columbia's existing and planned capital and O&M programs, Columbia will experience a revenue deficiency of approximately $55.3 million as detailed and supported in testimony of

Company witness Miller (Columbia Statement No. 4). This revenue deficiency is driven by two primary factors. First, Columbia has made, and continues to make, substantial capital investments in its system. As detailed in Company witness Soyster's testimony (Columbia Statement No. 7), since Columbia started its accelerated pipeline replacement program in 2007, Columbia has replaced 3,929,714 feet (over 744 miles) of cast iron and bare steel pipe. In 2015 alone, Columbia replaced over 97 miles of cast iron and bare steel pipe. To put these numbers into context, as shown in Figure 1 below (based on information publicly available from the 2014 Annual and DOT reports), Columbia exceeded the capital investments made by the other gas utilities in the Commonwealth. While this information is not intended to put Columbia in competition with the other gas utilities, it is provided to explain why Columbia is once again filing a base rate case while other gas utilities may not.

Figure 1



In addition to Columbia's past investments, Columbia intends to accelerate the pace of its capital replacement program in the future. In Columbia's 2015 Rate Case, at Docket No. R-2015- 2468056, Columbia forecasted that its 2015 and 2016 capital budgets for the replacement of cast iron and bare steel would be $145 million and $147 million, respectively. However, Columbia's 2015 actual investment for replacement pipe was $152 million and its age and condition capital budget for 2016 is $162 million. In other words, Columbia is investing $22 million more in replacing pipe during those two years than it had projected in the prior rate case. In addition, as detailed in the Company's response to Gas-ROR-014, the pertinent part of which is detailed in Figure 2 below, the Company intends to increase its capital investment in 2017 beyond what was contemplated last year, and it plans to continue to invest at an aggressive level through 2020 in order to retire as much bare steel and cast iron as possible.

Figure 2

GAS-ROR-014
Attachment A
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Columbia Gas of Pennsylvania
Capital Program
($000)

Gross View

Class	2016	2017	2018	2019	2020
Growth	$25,100	$23,400	$24,000	$24,900	$25,100
Betterment	$16,900	$20,400	$15,600	$8,700	$6,800
Public Improvement	$7,000	$4,800	$4,900	$4,900	$4,900
Replacement	$161,900	$204,400	$210,000	$210,000	$157,000
Support Services	$2,173	$3,887	$4,050	$3,500	$4,850
Automated Meter Reading	$500	$510	$710	$710	$1,300
Total Gross Capital	**$213,573**	**$257,397**	**$259,260**	**$252,710**	**$199,950**
Shared Services Allocation	$10,766	$7,829	$7,491	$7,847	$7,859
Fully Loaded Gross Capital	**$224,339**	**$265,226**	**$266,751**	**$260,557**	**$207,809**

I must note that Columbia's ability to increase its capital investment and maintain these unprecedented levels of investment is a result of Act 11's impact on reducing the regulatory lag that was previously associated with utility investment in Pennsylvania prior to the passage of Act 11.

Q. Why does Columbia want to increase its capital investment beyond current levels?

A. As shown in Figure 3 below, in terms of miles, Columbia's distribution system is the third largest in Pennsylvania.

Figure 3

NGDC	Miles of Pipe (2014)
Columbia Gas	7,443.10
PGW	3,023.00
PECO	6,779.70
UGI[1]	11,724.00
Peoples[2]	12,957.50
National Fuel	4,831.20

The size of the Company's capital program is largely driven by the amount of pipe that needs to be maintained and ultimately replaced. Just under 20% of Columbia's total inventory of pipe is either bare steel or cast iron and is nearing the end of its useful life and needs to be replaced. While the Company could invest lower amounts of capital and replace the remaining bare steel and cast iron pipe over a longer period of time, Columbia desires to further accelerate its replacement.

Q. Please explain.

A. The Company desires to accelerate its pipeline replacement program in order to take advantage of the current low price of gas in Pennsylvania. That is, by increasing its investment in pipeline replacement now, while gas prices are low, Columbia seeks to replace as much pipe as possible in order to ameliorate the

[1] All companies/ divisions combined.
[2] All companies/ divisions combined.

impact on the customer's total bill. Indeed, Columbia has calculated that, even after the entire increase requested in this proceeding is added to an average customer's bill, after adjusting for inflation, the average customer will be paying a total bill in 2017 that is about 29 percent less than they were paying in 2006, which is immediately before the time that Columbia began its accelerated pipeline replacement program. Stated another way, because all of the bare steel and cast iron pipe needs to be replaced at some point, the ideal time to make this investment is now, during a time of low gas costs so the impact to customers is minimized. Although gas prices may increase in the future, by increasing its capital investment now, while gas prices are low, the Company is attempting to reduce the need to increase capital spending during periods when gas prices may be high. In addition, as addressed in the testimony of Company witness Soyster, by removing deteriorating portions of its system, Columbia is enhancing the safety of its system by ensuring replacement of facilities with new and safer materials.

b. <u>Other Objectives</u>

Q. Does Columbia have any other objectives in this proceeding?

A. Yes, Columbia is seeking several tariff changes to make it easier for commercial and industrial customers to obtain gas service as well as requesting that transaction fees associated with all payment channel options available to residential customers be included in the cost of service.

III. REVENUE REQUIREMENT

Q. How did Columbia determine the revenue requirement for this case?

A. As described in the testimony of Company witness Miller (Columbia Statement No. 4), Columbia reviewed its costs to serve its customers using a fully forecasted rate year ending December 31, 2017, pro forma and adjusted for known and measurable changes. Columbia then compared the costs determined for the fully forecasted rate year to the revenues at present rates calculated for the fully forecasted rate year. This analysis produced a revenue deficiency, from which Columbia calculated the corresponding revenue requirement that Columbia will require to make up this deficiency, including a fair rate of return on the investment devoted to serving the public.

Q. Why is the proposed rate increase necessary to eliminate the revenue deficiency?

A. Columbia's current rates do not provide the opportunity for the Company to recover its costs to serve its customers, including a fair rate of return on the capital invested to provide distribution service to the public. The proposed rates have been developed to eliminate this deficiency and Company witness Moul (Columbia statement No. 8) will support Columbia's requested rate of return in his testimony.

Q. Without the increase requested in this case, what rate of return will Columbia experience?

A. Without the increase requested, Columbia's overall rate of return will drop to 5.96% in the Fully Forecasted Rate Year as shown on Exhibit 102, Schedule 3, Page 3.

Q. What overall rate of return and return on equity does Columbia propose in this case?

A. Columbia proposes an overall rate of return of 8.15%. Columbia witness Moul demonstrates that Columbia should be granted an opportunity to earn an 11% rate of return on common equity.

IV. <u>MANAGEMENT EFFECTIVENESS</u>

Q. What evidence supports adjusting the Company's requested rate of return for management effectiveness?

A. In addition to Columbia's aggressive pipeline replacement program detailed in the testimony of Columbia witness Soyster, which demonstrates the effectiveness of Columbia's management and its concern for excellence in customer service, I have obtained and analyzed the most recent Management Performance Audit reports from the Commission's website for Columbia, Peoples Gas Company, Philadelphia Gas Works, UGI, National Fuel Gas, Equitable Gas and PECO. The data appears as Exhibit MK-1, which is attached to my testimony. Initially, I would observe that the Commission's auditors employ a ranking category system that ranges from "Meets Expected Performance" to "Major Improvement Necessary" and they assign one of those ranking categories to various aspects of a utility company's management performance. I evaluated the number of rankings categories for each gas distribution company mentioned and determined the number of times the Commission's auditors assigned each of the various ranking categories to a gas distribution company. They are set forth in Figure 4, below.

Figure 4

Standard	CPA	Peoples	PGW	UGI	NFG	Equitable	PECO
Meets Expected Performance	50%	11%	0%	8%	13%	7%	20%
Minor Improvement Necessary	25%	44%	43%	42%	75%	47%	47%
Moderate Improvement Necessary	25%	22%	43%	33%	13%	33%	33%
Significant Improvement Necessary	0%	22%	14%	17%	0%	7%	0%
Major Improvement Necessary	0%	0%	0%	0%	0%	7%	0%
Total	100%	100%	100%	100%	100%	100%	100%

* Equitable is a division and that a management audit reflects combined Peoples/Equitable has not yet been completed

As Figure 4 illustrates, Columbia achieved the "Meets Expected Performance" ranking category in 50% of the categories evaluated by the auditors, more than twice as often as any of Columbia's peers. Also, Columbia was one of only three gas companies that did not receive any ranking of "Significant Improvement Necessary". A review of the information in Figure 4 and Exhibit MK-1 shows that, based on the Commission's own auditors, Columbia's performance exceeds that of its peers. Based on the totality of the evidence, the Commission should grant an increased return on equity based on Columbia's superior performance.

Q. Please provide evidence concerning the performance of Columbia's management in providing quality service to its customers.

A. Recently, the Commission issued its Annual Utility Consumer Activities Report and Evaluation ("UCARE") for 2014. The overall information contained in the report describes how well utilities handle consumer complaints. The report focuses on three main categories: Consumer Complaints, Payment Arrangement Requests ("PAR") and Compliance with Commission regulations.

Overall, Columbia's 2014 performance as reflected in the UCARE report appears to be the best in both the gas and electric industries. In the measure of Residential Consumer Complaints, Columbia had the lowest consumer complaint rate of (.48), per 1,000 residential customers in the gas industry. Columbia also had the lowest justified consumer complaint and the lowest justified rate per 1,000 residential customers of (.04). None of the electric utilities achieved better results than Columbia in these categories in 2014.

2014 Residential Consumer Complaint Rates
Justified Consumer Complaint Rates
Major Natural Gas Distribution Companies

Company	Consumer Complaint Rate	Justified Consumer Complaint Rate
Columbia	0.48	0.04
NFG	0.51	0.10
Peoples	0.52	0.12
Peoples-Equitable	0.77	0.05
PGW	3.02	0.38*
UGI- Gas	0.80	0.09
UGI Penn Natural	1.13	0.11
Average	1.03	0.13

*Justified consumer complaint rate based on a probability sample of cases

In the measure of PAR, Columbia's PAR rate per 1,000 residential customers of 2.06 was the best in the gas industry, as was its justified PAR rate and the PAR rate per 1,000 residential customers of (.04). None of the electric utilities achieved better results than Columbia during 2014.

2014 Residential Payment Agreement Request (PAR) Rates/
Justified PAR Rates*
Major Natural Gas Distribution Companies

Company	PAR Rate	Justified PAR Rate
Columbia	2.06	0.04
NFG	3.09	0.20
Peoples	2.50	0.15
Peoples-Equitable	4.52	0.05
PGW	15.66	0.49
UGI- Gas	7.56	0.53
UGI Penn Natural	10.81	1.04
Average	6.60	0.36

*All companies, with the exception of Columbia and NFG, have justified PAR rates based on a probability sample of cases

In the measure of Commission Infractions, Columbia had the lowest infraction rate per 1,000 residential customers of (.01) in the gas industry during 2014, which was consistent with 2013's rate of (.01). None of the electric utilities received better results than Columbia during 2014.

Commission Infraction Rates
Major Natural Gas Distribution Companies

Company	2012	2013	2014
Columbia	0.02	0.01	0.01
NFG	0.03	0.04	0.03
Peoples	0.20	0.16	0.08
Peoples-Equitable	0.02	0.02	0.01
PGW	0.28	0.43	0.20
UGI- Gas	0.03	0.01	0.08
UGI Penn Natural	0.04	0.03	0.03

Additionally, during 2015, Columbia voluntarily began to participate in Bureau of Consumer Services ("BCS'") Customer and Utility Resolution Effort ("CURE") Program. This initiative was designed to expedite the closing of the customer's complaint, whereby the Company can contact the customer and resolve the matter over the phone without BCS intervention. Since implementing this process, Columbia has been successful in closing roughly 24% of its informal complaints. The program has proved to be a win/win/win outcome for the customer, the Company and the Commission.

Q. Can you provide an overview of Columbia's 2015 Quality of Service Performance Report?

A. Yes, the "Quality of Service Performance Report" is organized in five general categories: Call Center Performance, Residential and Small Commercial Billing, Meter Reading, Dispute Reporting, and Customer Satisfaction. Columbia's performance for each of these categories is explained below.

1. <u>Call Center Performance:</u>

Columbia was pleased with the results of its 2015 Quality of Service Performance Report, particularly those statistics impacting call center performance. In 2015, Columbia experienced a marked improvement in its call answer rate within 30 seconds, from 77% in 2014 to 84% in 2015. Columbia attributes this improvement to the efficiencies gained from the development of a more highly trained and focused Universal Services Group. During 2015, Columbia restructured the contract it has with its service provider to revise the service level agreements ("SLA") to better align them with the Company's business needs and goals. These new SLAs, with a focus on key performance indicators and cost performance indices, will focus on improving call answer rates, call quality, first-call resolution and customer satisfaction. Early indications suggest the changes are working, as Columbia's Universal Services Group achieved an answer rate of 85% within 30 seconds in 2015, compared to 62% in 2014. In addition, Columbia's call center also experienced a significant decrease in its percent of calls abandoned, from 2.33% in 2014 to 1.54% in 2015.

Columbia continues to look for new ways to enhance its customer service and customer satisfaction through the implementation of online tools to assist our Customer Service Representatives ("CSRs"), as well as through a web self-serve mobile application that our customers can utilize to manage their own accounts.

2. <u>Residential and Small Commercial Billing Data:</u>

For the fourth consecutive year, Columbia did not have any deferred billings for its residential or small commercial customers in 2015. Columbia's Billing Group continued to exhibit a strong effort with investigation of billing abnormalities and has taken pride in achieving a zero deferred bill rate. I want to note that Columbia achieved this exceptional performance, despite having printed and mailed nearly 5 million bills to its customers, while investigating over 200,000 billing exceptions and related work.

3. Meter Reading:

Columbia continued the process of reducing the number of meter reading routes through rerouting projects, resulting in a cost saving to the Company's customers. In 2015, Columbia successfully rerouted nearly 190,000 accounts. By performing the reroute, Columbia effectively reduced its meter reading routes from 501 to 59 routes. Columbia was also successful in lowering its monthly average of unread meters covered under Section 56.12 of the Commission's regulations. Meters not read at the six month interval dropped from 10 accounts in 2014 to four accounts in 2015, and meters not read at the twelve month interval dropped from six accounts in 2014 to two accounts in 2015.

4. Dispute Reporting:

Columbia had 1 residential account where a Company response was not issued within the 30 day time frame as mandated under Section 56.151(5) of the Commission regulations. This was a training issue for a new employee that has since been resolved.

5. Customer Satisfaction:

Q. Are there metrics that Columbia utilizes to gauge customer satisfaction and the Company's effectiveness in providing quality customer service to its customers?

A. Yes, in addition to performing a thorough review and analysis of the Commission's UCARE, the Quality of Service Performance Report and the Universal Service and

Collections Report, Columbia uses three outside contractors to perform surveys to determine the effectiveness of satisfaction reported by its customers. Those contractors are Metrix/Matrix, Thoroughbred Research and J. D. Powers. Metrix/Matrix is the independent firm that also performs and reports data to the Commission, relative to its "Customer Transaction Survey," which is part of the Quality of Service Performance Report. Besides using these three independent parties, Columbia's call center performs a random post-call satisfaction survey to determine the effectiveness of its call center representatives.

Q. Can you share the results of these surveys?

A. Based on the results of the Thoroughbred Survey, Columbia has exhibited a strong history of providing quality of service to its customers. As reflected in the following tables, Columbia's Call Center Representatives continually achieve the 90%+ satisfaction mark in gauging Courtesy and Knowledge. The Metrix/Matrix Satisfaction Report also confirms this data. Additionally, Thoroughbred and Metrix/Matrix results for Columbia's Field Service Representatives easily met the 90%+ satisfaction threshold annually.

Customer Service Representative Results:

Columbia Gas of Pennsylvania	2009	2010	2011	2012	2013	2014	2015
Thoroughbred CSR Attributes	12-month Average	12-month Average	12-month Average	12-month Average	12-month Average	12-month Average	12-month Average
Being courteous and professional	90	96	100	96	100	97	96
Treating as respected customer	90	96	90	95	100	96	96
Showing concern for situation	90	93	90	93	90	94	93
Displaying knowledge in job	90	95	90	95	90	95	95
Adequately answering questions	90	95	90	95	90	95	95
Understanding purpose for call	90	94	100	95	90	95	94
Having authority to make decisions	90	92	90	91	90	92	92
Working quickly and efficiently	90	93	90	93	90	93	93

*Source document = Thoroughbred Survey website/Columbia Gas of PA/Monthly Flash Report

Field Representative Results:

2015	Columbia Gas Percent Satisfaction
Rep Handling Request	90%
Timely Completion	90%
Field Rep Response	91%
Field Rep Courtesy	96%
Field Rep Knowledge	96%
Respect of Property	100%
Field Rep Overall	97%
Contact Overall	92%

Q. How well did Columbia perform on "First Call Resolution" in 2015 with its Customers?

A. Over the past five years, Columbia has averaged a 79% "First Call Resolution" rate. This statistic indicates the success our call center has had in satisfying customers the first time they contact the Company.

2011	1st Call Resolution	2012	1st Call Resolution	2013	1st Call Resolution	2014	1st Call Resolution	2015	1st Call Resolution
Jan	74%	Jan	88%	Jan	81%	Jan	78%	Jan	82%
Feb	76%	Feb	79%	Feb	83%	Feb	81%	Feb	86%
Mar	90%	Mar	88%	Mar	80%	Mar	84%	Mar	80%
Apr	94%	Apr	79%	Apr	84%	Apr	69%	Apr	76%
May	86%	May	83%	May	70%	May	76%	May	83%
Jun	75%	Jun	69%	Jun	67%	Jun	84%	Jun	81%
Jul	72%	Jul	80%	Jul	79%	Jul	75%	Jul	74%
Aug	79%	Aug	80%	Aug	85%	Aug	82%	Aug	79%
Sep	84%	Sep	70%	Sep	75%	Sep	78%	Sep	78%
Oct	85%	Oct	79%	Oct	79%	Oct	81%	Oct	73%
Nov	69%	Nov	79%	Nov	77%	Nov	72%	Nov	77%
Dec	78%	Dec	88%	Dec	70%	Dec	81%	Dec	76%
YTD	**80%**	**YTD**	**80%**	**YTD**	**77%**	**YTD**	**79%**	**YTD**	**78%**
Target	**69%**	**Target**	**70%**	**Target**	**75%**	**Target**	**75%**	**Target**	**75%**

Q. How did Columbia perform in the 2015 J.D. Power Residential Customer Satisfaction Survey?

A. For the second consecutive year, Columbia was ranked first in Customer Satisfaction among all midsize utilities in the East Region. These results indicate Columbia's commitment and focus on meeting its customers' needs.

Q. What has been Columbia's success with implementing Chapter 14 Regulations?

A. Over the past 11 years, Columbia has been successful in implementing Chapter 14 regulations, which provide the necessary tools to reduce residential customer delinquency and write-offs. Based on data filed annually pursuant to the

Commission's regulations at Section 56.231, Columbia has reduced its gross residential write-off ratio from 4.81% in 2004 to 2.18% in 2014. It also reduced its net write-off for the same period from 3.48% to 1.43%. Columbia's slight increase in its net and gross write-offs in 2014 was due to the colder than normal weather experienced in our service territory during the 2013-2014 winter heating season.

Year	Gross Residential Revenues	Gross Residential Write-Offs	Gross Res. Write-Offs Ratio	Residential Recoveries	Net Residential Write-Offs	Net Res. Write-Offs Ratio
2004	$334,443,294.00	$16,079,652.00	4.81%	$4,453,039	$11,626,613	3.48%
2005	$422,316,022.00	$17,178,358.00	4.07%	$5,406,680	$11,771,678	2.79%
2006	$418,132,074.00	$12,725,454.00	3.04%	$3,878,311	$8,847,143	2.12%
2007	$402,803,625.00	$10,505,925.00	2.61%	$3,960,158	$6,545,767	1.63%
2008	$481,827,700.00	$10,874,843.00	2.26%	$3,613,578	$7,261,265	1.51%
2009	$387,454,010.00	$12,039,187.00	3.11%	$5,097,312	$6,941,875	1.79%
2010	$359,493,889.00	$8,162,827.00	2.27%	$3,454,140	$4,708,687	1.31%
2011	$346,316,467.00	$9,761,318.00	2.82%	$3,151,779	$6,609,539	1.91%
2012	$268,796,602.00	$7,585,766.00	2.82%	$2,765,170	$4,820,596	1.79%
2013	$329,063,560.00	$6,630,828.00	2.02%	$2,217,422	$4,413,406	1.34%
2014	$383,636,645.00	$8,357,228.00	2.18%	$2,853,475	$5,503,753	1.43%

Recently, the Commission's BCS issued a special collections report titled "Collections to Write Offs." The report analyzed collection data extracted from the Universal Services Program and Collections Report, over the past four years (2011 through 2014). In this report the BCS acknowledged Columbia for having a Best Practice, the BCS's comments addressed the following metric relative to payment agreements:

- In 2014, Columbia reported only 22.8% Debt <u>not</u> on a payment agreement for residential customers and 14.7% for Confirmed Low Income Customers.
- Since 2013, as compared to other Pennsylvania NGDCs, Columbia has had the highest number of Residential Customers in Debt on a Payment Agreement.

BCS acknowledged Columbia's focus on getting customers with past due monthly bills on a payment agreement, because of the lower collections risk to the utility.

Q. Can you identify any data that contributes to Columbia's success in dealing with its low income customers?

A. Based on information contained in the 2014 Universal Service and Collections Report, Columbia had the most affordable Customer Assistance Program ("CAP") payment plan in the Commonwealth. In 2014, Columbia's monthly average CAP bill was $59.00. This was the lowest bill amount of all gas utilities in the industry during 2014.

Q. Can you describe any process improvements that Columbia has made to serve its customers better?

A. During 2015, in order to enhance customer satisfaction and to better hear the "voice of our customers," Columbia created a consumer panel, made up of 1,000 residential customers throughout our Pennsylvania service territory. The focus of the group is to provide feedback on a variety of topics, which include the following items:

- 811 awareness and marketing of the 811 (call before you dig) phone number.
- Smell and Tell---what to do if you smell gas or otherwise suspect a gas leak.
- Customer expectations—considering new communication channels (i.e.: what type of information would customers want to obtain from a website, what type of information would customers want via text or automated phone call).
- E-Bill adoption and E-Payments.
- Implementation of a new bill format to be released in 2016.

Columbia also launched a number of new technologies in 2015, to further advance the customer's ability to manage their account and to improve customer service and satisfaction. These include the following:

- Provided capability for customers to enroll in both automatic payment and electronic billing from their mobile device.
- Launched new marketing content for new business. This included new online forms for use by prospective customers needing a service line/tap.
- Upgraded our Customer Relationship Management ("CRM") software to remain current with the software release version.
- Created templates for outbound customer e-mails to be used in case of gas emergencies or other related situations to quickly notify customers of the status of the situation.

As I mentioned previously, Columbia will be rolling out its new bill format in mid-2016. The Company is very excited about this initiative that has been in the works since early 2015. Focus group meetings were held in Pittsburgh throughout the year in order to share the new format with customers. Based on survey results of the focus group meetings, the new format was well received.

Columbia also signed a new gas supply contract for its CAP customers. This will provide Columbia's CAP customers with a discounted gas supply cost, further assisting the Company's low income customers. Additionally, Columbia implemented rolling enrollment for participants in its CHOICE program. This change allows natural gas suppliers on the Columbia system to enroll customers at any time without delay. Prior to this change, an enrollment could have taken up to 45 days.

Finally, in 2015, Columbia completed programming that will provide our Commercial and Industrial customers with the ability to make payments electronically.

Q. Please explain Columbia's efforts in expanding the availability of natural gas throughout Pennsylvania.

A. To date, 94 customers have signed up for gas service under Columbia's Pilot Rider New Area Service, which was approved in case P-2014-2407345. The Pilot Rider New Area Service enabled two residential developments to select natural gas for their heating source instead of electric or propane. In addition, in the Company's

2015 Rate Case, R-2015-2468056, three New Business proposals were authorized to expand access to natural gas service. These new programs consist of the following: 150 foot main allowance per residential applicant; 150 foot service line allowance in the geographic areas where the Company owns the service line, and; the house piping reimbursement program. To date the Company has signed 15 service line agreements (e.g no main extension is required) and 10 main line extension agreements with customers to expand the use of natural gas.

Q. Does the Company have any additional proposals to expand the availability of natural gas service in Pennsylvania?

A. Yes, Company witness Waruszewski's testimony details two additional proposals that seek to expand the availability of natural gas among large commercial and industrial customers, as well as the multifamily housing sector.

V. INTRODUCTION OF WITNESSES

Q. Please introduce Columbia's witnesses and describe their testimony.

A. Columbia presents the following witnesses:

- Columbia witness Amy Efland, the Lead Forecast Analyst for NCSC provides demand forecasting services for Columbia. In Columbia Statement No. 2, she explains how residential and commercial sales volumes are normalized for weather. The results of the normalization procedure are contained in Company witness Bell's testimony (Columbia Statement No. 3) and Exhibit 3, Schedule 4.

Company witness Efland also explains the projection of the future test year and fully forecasted rate year customer and load growth and comments on the residential consumption per customer.

- Company witness Melissa Bell is a Lead Regulatory Analyst for NCSC. She provides support for regulatory filings for Columbia. In Columbia Statement No. 3, Company witness Bell supports the Company's requested increase in base rates by providing detailed information on the Company's pro forma operating revenues for the historical test year and for the twelve months ending December 31, 2017 (Fully Forecasted Rate Year). Company witness Bell also supports the Company's proposed revenue allocation and rate design.
- Company witness Kelley Miller is a Lead Regulatory Analyst for NCSC and provides regulatory accounting and strategy services to Columbia. In Columbia Statement No. 4, Company witness Miller presents Columbia's cost of service and quantifies the revenue deficiency based on operating costs and revenues, as adjusted. Company witness Miller supports Columbia's Cost of Service O&M expenses. In addition, she provides a comparison of actual O&M expenses for the twelve months ended November 30, 2015, to the projections that were included in the Company's last base rate proceeding, R-2015-2468056.
- Company witness John J. Spanos is a Senior Vice President in the Valuation and Rate Division of Gannett Fleming, Inc. In Columbia Statement No. 5,

Company witness Spanos supports the depreciation study Gannett Fleming prepared for Columbia's gas plant.

- Company witness Nicole Paloney is Director of Rates and Regulatory Affairs for Columbia. In Columbia Statement No. 6, she provides detail and support about the methods and assumptions used to develop the Historic Test Year, Future Test Year and the Fully Forecasted Rate Year rate base as presented in Exhibits 8 and 108.
- Company witness Wesley Soyster is the Director of Construction for NCSC. In Columbia Statement No. 7, Company witness Soyster provides an overview of Columbia's distribution system and discusses Columbia's ongoing replacement activities and provides testimony in support of Columbia's plant additions through the Fully Forecasted Future Rate Year (twelve-months ending December 31, 2017). He also discusses Columbia's historic operating performance, the initiatives taken to improve its overall safety and compliance efforts and the metrics that are used to track performance and progress, and the planned system enhancements to Columbia's operations.
- Company witness Paul Moul is the Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. In Columbia Statement No. 8, Company witness Moul presents detailed testimony and documentation and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Commission should recognize

in the determination of the revenues that Columbia should be given an opportunity to earn as a result of this base rate case. His recommendation is supported by detailed financial data and an in-depth explanation of the application of the various financial models upon which he relies.

- Company witness Nancy J. D. Krajovic is the State Finance Director for Columbia and is responsible for analysis and support in the financial planning, forecasting and O&M and capital budgeting processes for Columbia and coordination with the NiSource Corporate financial planning and budgeting processes. In Columbia Statement No. 9, Company witness Krajovic provides testimony in support of the budgeted O&M expenses for the Fully Forecasted Rate Year that are included in Columbia witness Miller's cost of service analysis.
- Company witness Panpilas W. Fischer is the Tax Director at NCSC and she provides Tax Accounting services for Columbia. In Columbia Statement No. 10, Company witness Fischer supports Columbia's income tax and other tax expense included in the cost of service. She provides detail about both federal and state income tax recovery, and reduction of rate base for deferred income taxes.
- Company witness Mark Balmert is the Director of Regulatory Strategy & Support for NCSC which provides services and support to Columbia for its regulatory needs. In Company Statement No. 11, he testifies about Columbia's allocated cost of service studies.

- Company witness Shirley Bardes-Hasson is Manager, Regulatory Policy for Columbia and is responsible for managing regulatory activity before the Commission, including ensuring timely, accurate regulatory filings as well as monitoring regulatory cases, and making recommendations for Company participation in those cases when warranted. In Columbia Statement No. 12, Company witness Bardes-Hasson explains and supports the tariff changes that the Company seeks to make in this proceeding.
- Company witness Robert C. Waruszewski is Columbia's Senior Regulatory Analyst. In Company Statement No. 13, he provides testimony concerning new proposals designed to expand the availability of natural gas service across Columbia's service territory. In addition, he is sponsoring Columbia's request to include in the cost of service transaction fees associated with all payment channel options available to residential customers.
- Company witness Deborah Davis is Columbia's Manager of Universal Services. In Company Statement No. 14, she addresses potential sources of additional funds for Columbia's existing Hardship Fund as ordered in Columbia's 2015 rate base proceeding, R-2015-2468056.

Q. Are you sponsoring any exhibits in this proceeding?

A. Yes. In addition to the one exhibit attached to this testimony, I am sponsoring Exhibit No. 13, Schedule 3, which cross references the standard filing requirements with the corresponding Exhibits and Schedules in this filing for both the historic and future test years.

Q. Does this conclude your direct testimony?

A. Yes.

Exhibit I – 1
Columbia Gas of Pennsylvania, Inc.
Focused Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Corporate Governance		X			
Executive Management and Organizational Structure	X				
Affiliated Interests	X				
Financial Management		X			
Customer Service			X		
Gas Operations			X		
Emergency Preparedness	X				
Human Resources	X				

D. Benefits

Where possible, the Audit Staff attempts to quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. However, for the majority of recommendations, it is not possible or practical to estimate quantitative benefits as their benefits are of a qualitative nature or there was insufficient data available to quantify the impact. For example, it is difficult to estimate the actual benefit where new management practices or procedures are recommended where such did not previously exist or was not fully functional. Similarly, changes in work flow processes or to implement good business practices will result in improved effectiveness and efficiency of a specific function but cannot be easily quantified.

The Company will have varying ways to implement the recommendations and as a result the Audit Staff has not estimated the cost of implementation for recommendations where no savings were quantified. However, it should be noted by the reader that the cost of implementing certain recommendations could be significant.

E. Recommendation Summary

Chapters III through X provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this focused audit. Exhibit I-3 summarizes the recommendations with the following priority assessments for implementation:

Exhibit I – 1
The Peoples Natural Gas Company
Focused Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Corporate Governance	X				
Executive Management		X			
Affiliated Relationships		X			
Gas Operations				X	
Emergency Preparedness			X		
Customer Service				X	
Human Resources		X			
Materials Management		X			
Diversity & EEO			X		

D. Recommendation Summary

Chapters III through XI provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this focused audit. Exhibit I-2 summarizes the recommendations with the following priority assessments for implementation:

- HIGH PRIORITY – Implementation of the recommendation would result in significant cost savings, major service improvements, and/or substantial improvements in management practices and performance. These recommendations should be implemented as soon as practical.

- MEDIUM PRIORITY – Implementation of the recommendation would result in important cost savings, service improvements, and/or meaningful improvements in management practices and performance. Implementation of these recommendations should begin within 12 months.

- LOW PRIORITY – Implementation of the recommendation could potentially enhance cost controls, service improvements, and/or management practices and performance. Implementation of these recommendations should begin within 18 months.

These priorities were assigned based on the Audit Staff's assessment of the potential impact of the recommendations and the Company's available resources.

however, each rating is utility specific; i.e., the rating of PGW cannot be directly compared with that of another utility.

Schumaker & Company's overall assessment of each work plan area is presented in the *Functional Evaluation Summary* shown in *Exhibit I-1* and *Exhibit I-2*, with the specific criteria used as follows:

- *Optimum* – The area is functioning more than adequately and no recommendations were made.
- *Minor improvement necessary* – The area is generally functioning adequately, but minor improvements are recommended.
- *Moderate improvement necessary* – The area is generally functioning adequately, but some substantial opportunities for improvement were recommended.
- *Significant improvement necessary* – The area is not functioning adequately and many recommendations, requiring considerable effort, need to be implemented to achieve adequate performance.
- *Major improvement necessary* – The area is not functioning effectively or efficiently and many recommendations need to be implemented to achieve adequate performance. Implementation of these recommendations will have a major effect on cost levels and performance for PGW.

Exhibit I-1
Functional Evaluation Summary
Phase I – Diagnostic Review

		Evaluative Ratings				
Chapter	**Function**	**Optimum**	**Minor Improvement Necessary**	**Moderate Improvement Necessary**	**Significant Improvement Necessary**	**Major Improvement Necessary**
II	Executive Management & Human Resources					
	Executive Management		X			
	External Relations		X			
	Human Resources			X		
III	Support Services					
	Information Technology		X			
	Transportation Management			X		
	Facilities Management		X			
	Procurement Services				X	
	Risk Management		X			
	Legal Services		X			

Exhibit I-2
Functional Evaluation Summary
Phase II – Pre-identified Issues Review

		Evaluative Ratings				
Chapter	**Function**	**Optimum**	**Minor Improvement Necessary**	**Moderate Improvement Necessary**	**Significant Improvement Necessary**	**Major Improvement Necessary**
IV	Corporate Governance			X		
V	Financial Management			X		
VI	Diversity and EEO			X		
VII	System Reliability Performance & Other Related Operations			X		
VIII	Customer Service				X	

D. Summary of Estimated Benefits

The audit produced 93 recommendations, which are contained in this report. A summary of the number of priority items, and estimated benefits, is grouped by phase. Following is a brief explanation of these categories of information.

Priority

To assist PGW management in developing implementation plans, each recommendation has been assigned a priority of "high," "medium," or "low" according to the following criteria:

- *High* – Designated recommendations are high priority because of their importance and urgency. These represent significant benefit potential, major improvements to service, or substantial improvements to methods or procedures.
- *Medium* – Designated recommendations are of medium priority. In some instances, the implementation of these recommendations is expected to provide moderate improvements in profitability of operations, or management methods and performance. In other instances, implementation may provide significant longer-term benefits which are less predictable.
- *Low* – Designated recommendations reflect a lower priority. In many instances, they should be studied further or implemented sometime during the next few years. Potential benefits are perceived to be either modest or difficult to measure.

Exhibit I – 1
UGI Utilities, Inc.
UGI Central Penn Gas, Inc.
UGI Penn Natural Gas, Inc.
Focused Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure		X			
Corporate Governance	X				
Affiliated Interests and Cost Allocations			X		
Financial Management		X			
Gas Operations				X	
Electric Operations			X		
Emergency Preparedness			X		
Materials Management				X	
Customer Service		X			
Fleet Management		X			
Human Resources and Safety Programs		X			
Diversity			X		

D. Recommendation Summary

Chapters III through XIV provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this focused audit. Effective implementation of the recommendations would result in cost savings, service improvements, and/or improvements in management practices and performance. Exhibit I–2 summarizes the recommendations with the following priority assessments for implementation:

- HIGH PRIORITY – Implementation of these recommendations should begin within six months and be completed as soon as practical.
- MEDIUM PRIORITY – Implementation of these recommendations should begin within 12 months.
- LOW PRIORITY – Implementation of the recommendations should begin within 18 months.

Exhibit I-1
National Fuel Gas Distribution Corporation
Focused Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management & Organizational Structure		X			
Corporate Governance		X			
Affiliated Interests			X		
Financial Management		X			
Emergency Preparedness		X			
Diversity & EEO		X			
Customer Service		X			
Gas Operations	X				

D. Recommendation Summary

Chapters III through X provide findings, conclusions, and recommendations for each function or area reviewed in-depth during this focused audit. Exhibit I-2 summarizes the recommendations with the following priority assessments for implementation:

- HIGH PRIORITY – Implementation of the recommendation would result in significant cost savings, major service improvements, and/or substantial improvements in management practices and performance. These recommendations should be implemented as soon as practical.

- MEDIUM PRIORITY – Implementation of the recommendation would result in important cost savings, service improvements, and/or meaningful improvements in management practices and performance. Implementation of these recommendations should begin within 12 months.

- LOW PRIORITY – Implementation of the recommendation could potentially enhance cost controls, service improvements, and/or management practices and performances. Implementation of these recommendations should begin within 18 months.

These priorities were assigned based on the Audit Staff's assessment of the potential impact of the recommendations and the Companies' available resources.

Equitable Gas Management Report

Exhibit I-2
Functional Evaluation Summary
Phase I – Diagnostic Review

Chapter	Function	Evaluative Ratings: Optimum	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
II	Executive Management & Human Resources					
	Executive Management			X		
	Human Resources			X		
III	Financial Management		X			
IV	Support Services					
	Information Technology			X		
	Transportation Management		X			
	Facilities Management		X			
	Procurement Services		X			
	Risk Management		X			
	Legal Services		X			
V	Gas Supply & Operations			X		

Exhibit I-3
Functional Evaluation Summary
Phase II – Pre-identified Issues Review

Chapter	Function	Evaluative Ratings: Optimum	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
VI	Corporate Governance		X			
VII	Affiliate Interests					X
VIII	Operational Performance				X	
IX	Customer Service	X				
X	Diversity & EEO			X		

Exhibit I-1
PECO Energy Company
Focused Management and Operations Audit
Functional Rating Summary

Functional Area	Meets Expected Performance Level	Minor Improvement Necessary	Moderate Improvement Necessary	Significant Improvement Necessary	Major Improvement Necessary
Executive Management and Organizational Structure			X		
Corporate Governance		X			
Affiliated Interest and Cost Allocations		X			
Financial Management		X			
Electric Operations			X		
Gas Operations			X		
Emergency Preparedness		X			
Materials Management			X		
Customer Service			X		
Information Technology	X				
Fleet Management		X			
Facilities Management	X				
Risk Management	X				
Legal		X			
Human Resources and Diversity		X			

D. <u>Benefits</u>

Where possible, the Audit Staff attempts to quantify the potential savings that would be expected from effectively implementing the recommendations made in this report. The audit report contains identifiable potential quantifiable cost savings of approximately $2,933,000 to $5,667,000 in annual savings and $2,200,000 to $3,110,000 in one-time savings from effective implementation of the recommendations. We try to identify, whenever it is reasonably practical, the potential savings net of the projected costs for implementation. Some of these savings could be considered an actual reduction in costs, avoided costs or increased revenues; whereas others would result from better deployment and/or use of existing resources. These quantifications require some judgment and may require efforts beyond the scope of the audit for further refinement. Therefore the actual benefits from effective implementation of the recommendations are subject to some degree of uncertainty, and could be higher or lower than the amounts estimated by the Audit Staff. An overall summary of the annual and one-time cost savings quantified in the audit report are shown in Exhibit I-2.

COLUMBIA STATEMENT NO. 2

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2016-2529660
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
AMY L. EFLAND
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. My name is Amy L. Efland and my business address is 290 W. Nationwide Blvd. Columbus, Ohio 43215.

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

A. I am a Lead Forecasting Analyst employed by NiSource Corporate Services Company.

Q. What are your responsibilities as Lead Forecasting Analyst?

A. I assist with the development of short-range and long-range forecasts of customers, energy consumption and peak demand for seven NiSource gas distribution companies, including Columbia Gas of Pennsylvania ("Columbia" or the "Company") and one NiSource electric company. I also assist with other business related analyses and forecasts.

Q. What is your educational and professional background?

A. I attended Earlham College where I earned a Bachelor of Arts Degree in Economics and Miami University where I earned a Master of Arts Degree in Economics. From 1997 to 2002, I worked as a forecast analyst for Cinergy, assisting with the production of the gas and electric long-term forecasts of customers, energy consumption and peak demand for the Cinergy (Public Service Indiana, Union Light, Heat & Power, and Cincinnati Gas & Electric) territories. I was promoted to Lead Analyst in 2002, a position I held until I left Cinergy in 2005. From 2005 to

2006, I worked as a Senior Forecasting Analyst with Limited Brands/Victoria's Secret Direct. I provided analysis and recommendations surrounding circulation levels of catalogues and assisted with catalogue messaging relating to marketing offers. From 2006 to 2008, I worked as a Senior Marketing Analyst for JP Morgan Chase where I was responsible for the development of test designs for consumer and business banking marketing programs. I joined NiSource in 2008 as a Senior Forecast Analyst. In 2014, my title was changed to Lead Forecasting Analyst reflecting the same responsibilities I held while a Senior Forecast Analyst.

Q. Have you testified before this or any other Commission?

A. Yes, I have provided direct testimony related to weather normalization and customer usage trends before the Pennsylvania Public Utility Commission ("Commission"), Docket Nos. R-2009-2149262, R-2010-2215623, R-2012-2321748, R-2014-2406274, R-2015-2468056 and the Kentucky Public Service Commission, Case No. 2009-00141.

Q. What test years will you be addressing in this testimony?

A. I will be addressing the twelve-month period ending November 30, 2015 as the Historic Test Year ("HTY"), the twelve-month period ending November 30, 2016 as the Future Test Year, and the twelve-month period ending December 31, 2017 as the Fully Forecasted Rate Year.

Q. What is the purpose of your testimony in this proceeding?

A. I will explain how residential and commercial sales are normalized for weather. The results of the normalization process are contained in Company witness Bell's testimony (Columbia Statement No. 3) and Exhibit 3 Schedule 4. I will also explain sales growth and comment on the residential consumption per customer.

II. Weather Normalization Process

Q. Please explain the weather normalization process.

A. For each month of the HTY for the residential and commercial classes, actual billing month sales per customer is separated into base-usage and temperature-sensitive usage. Temperature-sensitive usage is then scaled by the ratio of normal to actual heating degree days ("HDD") to derive normal temperature-sensitive use per customer. The normal temperature-sensitive use per customer is then added to the base-use per customer to arrive at the normal sales per customer. This value is then multiplied by the customer count to derive the normal sales.

Q. What data sources did you use for your calculations?

A. I used the Company's billing records to obtain monthly customer counts and billed sales. The temperatures used to calculate HDD were obtained from National Weather Service weather stations throughout the Company's service territory. Due to the geographical dispersion of Columbia's customers, temperature data from multiple weather stations is used. A weighted average HDD for the Company is calculated using the percent of residential heating customers assigned to each station as a weight for that station.

Q. How does the process calculate base usage?

A. The process assumes no temperature sensitive (heat) usage in July and August. For September, no temperature sensitive (heat) use is assumed when total use per customer per day (Total Use/Customer/Day) is less than July and/or August. The base use per customer per day is calculated by taking the average of the two lowest observed values from the months of July through September.

Q. How does the process weather normalize monthly sales?

A. First, the monthly base use per customer is determined. This equals the lesser of the base use per customer per day multiplied by the days in the billing cycle ((base use /customer/day)*days in billing cycle) or the monthly total use per customer. Second, monthly heat use per customer is calculated. Heat use per customer equals the total use per customer minus the base use. Third, the heat use per customer is normalized by multiplying by a ratio of Normal HDD to Actual HDD. Finally, normal use per customer is calculated by adding the base use per customer to the normal heat use per customer. Total monthly normalized usage is generated by multiplying monthly customers by the monthly normal use per customer. This calculation for the HTY is prepared separately for residential and commercial customers and the results are presented in Exhibit 10, Schedule 8.

Q. Has the process for normalizing weather changed from Columbia's last rate filing?

A. No, the process has not changed other than updating the historic averages to include the most recent 20- year history. Normal weather is defined in this filing as the average HDD for the 20 years ended 2015. The previous base rate case filing defined normal weather as the 20-year average ending in 2013. In all other respects, the normalization process is the same.

Q. Why is Columbia using the 20-year average?

A. The settlement of the Company's 2015 base rate proceeding at Docket No. R-2015-2468056 designed rates based upon the Company's proposed throughput volumes, which reflected the Company's use of the 20-year average. Consistent with the Company's approach since 2008, the Company proposes to continue to use the 20-year average because an analysis of weather data shows that a rolling 20-year average is a superior measure to a rolling 30-year average. Table 1 below illustrates that, as a predictor of one-year-ahead weather, the 20-year average outperforms the 30-year average in 69% of the most recent 36 years. Table 1 also illustrates that the 20-year average has a lower mean absolute error, as compared to the 30-year average when considering both the most recent 36 year period and the most recent 10 year period.

In Table 2, the averages are used every year to predict each five year period for the 5-years ended 1985 through the five years ended 2015. In this analysis, the performance of the 20-year averages are compared to the 30-year average. When determining the smallest difference over the 5-year period, the 20-year average outperforms the 30-year average in 84% or 26 out of the 31 periods. When considering the most recent 10 periods, the 20-year average outperforms the 30-year average in 100% or all of the 10 periods.

Table 3 demonstrates that stability is not sacrificed when using a 20-year average. The average annual change for the 20-year average is 0.4%, while the average annual change for the 30-year averages is 0.3%. The 20-year normal is not only a better predictor, but also a more dynamic measure that is better able to react more quickly to change because it replaces 5% of the data each year rather than the 3% that is replaced with the 30-year average. This is particularly important, given the Company's frequent rate case filings. In conclusion, the 20-year measure performs better as compared to the 30-year in both the year ahead analysis and the five year analysis, and is both a better predictor and a more dynamic measure when compared to the 30-year average.

Table 1
Weather Averages as Predictors
Moving Averages used to Predict Following Years
Columbia Gas of Pennsylvania

	Annual Heating Degree Days			Absolute Error		Better 1-year predictor	
	Actual	20-yr Average	30-yr Average	20-yr Average	30-yr Average	20-yr Average	30-yr Average
1980	6010	5877	5766				
1981	6219	5887	5790	342	453	x	
1982	5915	5880	5811	28	125	x	
1983	5568	5848	5831	312	243		x
1984	6064	5860	5853	216	233	x	
1985	5236	5831	5845	624	617		x
1986	5571	5818	5839	260	274	x	
1987	5456	5796	5838	362	383	x	
1988	5892	5791	5835	96	54		x
1989	5724	5778	5833	67	111	x	
1990	5071	5737	5808	707	762	x	
1991	4908	5692	5771	829	900	x	
1992	5558	5680	5755	134	213	x	
1993	5455	5693	5730	225	300	x	
1994	5719	5709	5726	26	11		x
1995	5427	5706	5713	282	299	x	
1996	6005	5704	5719	299	292		x
1997	5641	5681	5711	63	78	x	
1998	4590	5601	5664	1091	1121	x	
1999	5166	5560	5637	435	498	x	
2000	5403	5529	5621	157	234	x	
2001	5385	5488	5606	144	236	x	
2002	5304	5457	5590	184	302	x	
2003	5825	5470	5611	368	236		x
2004	5329	5433	5608	141	282	x	
2005	5564	5450	5611	131	44		x
2006	5175	5430	5582	275	436	x	
2007	5295	5422	5555	135	287	x	
2008	5526	5404	5533	104	29		x
2009	5447	5390	5515	44	86	x	
2010	5400	5406	5495	10	115	x	
2011	5421	5432	5468	15	74	x	
2012	4669	5387	5426	763	799	x	
2013	5486	5389	5424	99	60		x
2014	5950	5400	5420	561	526		x
2015	5492	5404	5428	92	72		x

	Mean Absolute Error		Frequency of Lowest Absolute Error	
1981-2015	275	308	24	11
2006-2015	210	248	6	4

Relative Frequency of Lowest Absolute Error		
1981-2015	69%	31%
2006-2015	60%	40%

Table 2

Weather Averages as Predictors

Moving Averages used to Predict the Following Five Years

Columbia Gas of Pennsylvania

	Annual Heating Degree Days			Five Year Sum of Errors		Better 5-year predictor	
	Actual	20-yr Average	30-yr Average	20-yr Average	30-yr Average	20-yr Average	30-yr Average
1980	6010	5877	5766				
1981	6219	5887	5790				
1982	5915	5880	5811				
1983	5568	5848	5831				
1984	6064	5860	5853				
1985	5236	5831	5845	-382	173		x
1986	5571	5818	5839	-1080	-597		x
1987	5456	5796	5838	-1506	-1159		x
1988	5892	5791	5835	-1022	-937		x
1989	5724	5778	5833	-1422	-1386		x
1990	5071	5737	5808	-1442	-1512	x	
1991	4908	5692	5771	-2040	-2146	x	
1992	5558	5680	5755	-1827	-2038	x	
1993	5455	5693	5730	-2239	-2458	x	
1994	5719	5709	5726	-2179	-2454	x	
1995	5427	5706	5713	-1619	-1975	x	
1996	6005	5704	5719	-297	-693	x	
1997	5641	5681	5711	-151	-529	x	
1998	4590	5601	5664	-1083	-1268	x	
1999	5166	5560	5637	-1715	-1803	x	
2000	5403	5529	5621	-1725	-1762	x	
2001	5385	5488	5606	-2334	-2412	x	
2002	5304	5457	5590	-2557	-2706	x	
2003	5825	5470	5611	-924	-1236	x	
2004	5329	5433	5608	-553	-937	x	
2005	5564	5450	5611	-240	-696	x	
2006	5175	5430	5582	-241	-835	x	
2007	5295	5422	5555	-98	-760	x	
2008	5526	5404	5533	-461	-1165	x	
2009	5447	5390	5515	-159	-1035	x	
2010	5400	5406	5495	-405	-1212	x	
2011	5421	5432	5468	-60	-820	x	
2012	4669	5387	5426	-646	-1313	x	
2013	5486	5389	5424	-595	-1244	x	
2014	5950	5400	5420	-22	-649	x	
2015	5492	5404	5428	-13	-455	x	

	Mean Error		Frequency of Lowest Error	
1985-2015	-1001	-1291	26	5
2005-2015	-270	-949	10	0

	Relative Frequency of Lowest Error	
1985-2015	84%	16%
2006-2015	100%	0%

Table 3

Stability of Weather Averages Annual Change in Averages 1981-2015 Absolute Values Columbia Gas of Pennsylvania			
	20-yr Average	30-yr Average	Annual HDD
Average	0.4%	0.3%	6.8%
Maximum	1.4%	0.8%	18.6%

III. Forecast Method

Q. Please explain the methodology employed for developing the forecasted number of customers and customer usage for the Future Test Year and the Fully Forecasted Rate Year.

A. Development of the forecasting methodology is presented in the summary that follows. This method was used to develop both the Future Test Year and the Fully Forecasted Rate Year. Price information included in the models is from the Company's databases, and average efficiency data is from Itron Inc., a national utility consulting firm. The economic variables and deflator information are from IHS Global Insight, Inc., a data consultant, and weather data is provided by Schneider Electric, a weather consulting service.

Residential and Commercial Customers

- Total new customer additions are forecasted for the initial three years of the forecast by Columbia's New Business Team. CHOICE customers are calibrated to the most recently observed level and the forecast is set to the current observed percentage of customers participating in the CHOICE program.

- Traditional transportation customers = existing transportation customers + new customers identified by the Large Customer Relations group.
- Existing customers are forecasted using the latest historical level. The forecast is calculated by applying an attrition rate calculated using recent historical data. The attrition rate is applied to the latest existing level of customers at the time the forecast is being prepared. The attrition rate used for the Future Test Year and Fully Forecasted Rate Year is 0.5% for Residential and 1.2% for Commercial.
- Total customers = existing customers + new customers – attrition customers
- Sales customers = total customers – CHOICE customers – traditional (commercial) transportation customers

Residential Dekatherm ("Dth")/customer

- Residential use per customer is forecasted with an econometric model that incorporates real price, an average efficiency variable, real per capita income, and heating degree days. Residential CHOICE usage follows the total Residential usage trend.

Residential Volume

- Dth is forecasted for existing and new construction customers

  Dth = customers * Dth/customer

- CHOICE Dth forecasted as

  CHOICE Dth = customers * Dth/customer

- Sales Dth forecasted as residual

Sales Dth = Dth – CHOICE Dth

Commercial Dth/customer

- Commercial use per customer is forecasted with an econometric model that incorporates real price, real gross county product, average efficiency variable, and heating degree days. Commercial CHOICE usage follows the total Commercial usage trend.

Commercial Dth

- Dth is forecasted for existing and new construction customers

  Dth = customers * Dth/customer

- CHOICE Dth is forecasted as

  CHOICE Dth = customers * Dth/customer

- Non-CHOICE transportation Dth for large commercial customers is forecasted by the Large Customer Relations group. Non-CHOICE transportation Dth for smaller commercial customers is forecasted as the trend in the forecast for total commercial use per customer.
- Sales Dth forecasted as residual

  Sales Dth = Dth – CHOICE Dth – non-CHOICE transportation

Industrial Volume

- The majority of the Industrial class forecast is provided by the Large Customer Relations group. This portion constitutes 92% of the total Industrial class forecast. The large customer portion of the forecast is developed by incorporating information generated through individual customer interviews. The remainder of the industrial class forecast is estimated using the trend from an econometric model for the full class. The model incorporates real price, manufacturing employment, industrial production, and heating degree days. The total industrial volume forecast is the sum of the large industrial forecast and the all other industrial forecast.

- The information provided through the interviews with customers provides sales/transportation detail. Additional transportation Dth is forecasted with the trend from the econometric model.

Q. Please discuss the past performance of the forecast.

A. Residential and commercial forecast models are updated annually with the most current data. An internal review of forecast performance occurs on a regular basis. Variances for the residential and commercial predictions are calculated and assessed in order to measure accuracy. The average annual one year weather normalized variance for the residential models is 1.3%. For commercial, the average one year variance of the forecast is 2.3%.

III. Trend in Residential Use Per Customer

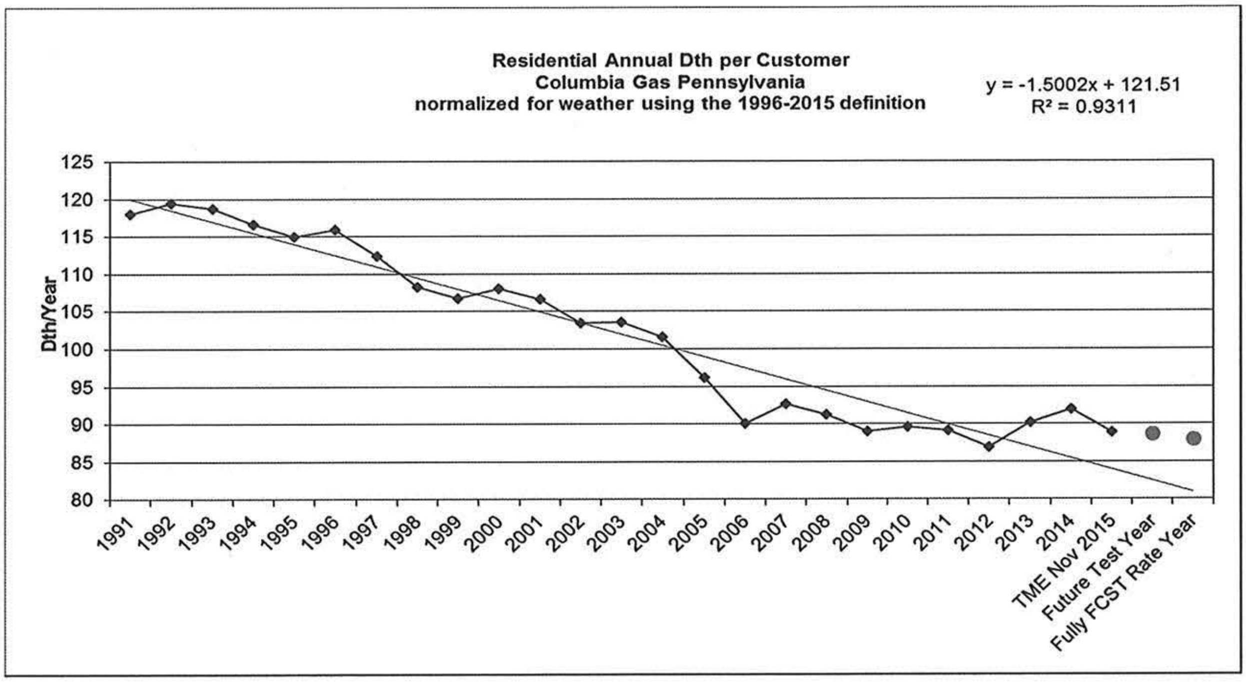
Q. Describe Columbia's recent trends related to residential use per customer.

A. Historical data shows a steady decline in residential use per customer from 1991 to 2009 and a more modest decline starting in 2010. Periods exhibiting an increase in use have all been followed closely by periods of decreasing usage, indicating that these points are not representative of the overall trend. The most recent example illustrating this is comparing the 2014 period with the HTY period ending November 2015. Residential usage dropped from the 2014 level of 91.96 Dth to 88.89 Dth for the HTY period reflecting over a 3% decline in usage. Moreover, aside from 2012, the current HTY twelve month period usage level of 88.89 Dth reflects the lowest usage level illustrated on the graph and further indicates that usage continues to decline at a modest rate.

The variance reflected in the most recent periods of residential use per customer can be attributed to unusual weather patterns that mask the overall trend. For example, unusually warm weather during the winter of 2011-2012 resulted in a consumption response, as measured by temperature sensitive use per customer per heating degree day, from residential customers, that was notably below that of recent years. This was followed by unusually cold weather during the winter of 2013-2014 that resulted in a consumption response notably above that of recent years. With the return of more temperate weather, as reflected in the HTY period, the underlying downward trend continues. The downward trend in residential usage is projected to continue into the Future Test Year and the Fully Forecasted Rate Year. The Forecasted Test Year and the Fully Forecasted Rate Year usage projections can be found in Exhibit No. 10 Schedule 2 on pages 7 and 8 and are included in the chart below. The Future Test Year usage level of 88.65 Dth and the Fully Forecasted Rate Year usage level of 87.99 Dth reflect historical use per customer trends and are in line with recent data. The points represent a decline in usage from the HTY, acknowledging the overall downward trend in usage.

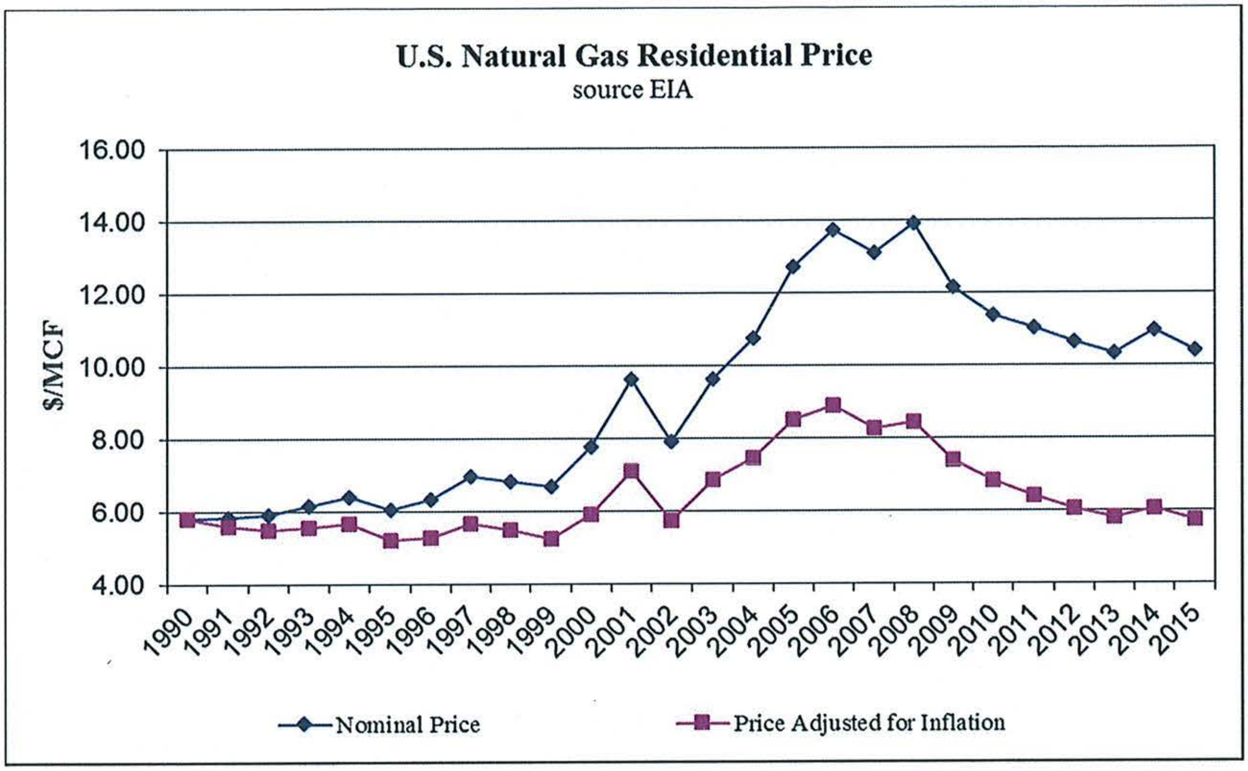
However, both the Future Test Year and the Fully Forecasted Rate Year usage levels are well above the data trend line and both take into account recent trends and usage levels.

Residential use per customer trends are depicted in the chart below:



Q. What factors are causing the reduction in residential customer usage?

A. Throughout most of the 1990s natural gas consumption per residential customer decreased by 1% to 2% per year. This decline in consumption occurred in spite of a relatively constant nominal price, as is illustrated in the graph below.



When adjusted for inflation, the price actually decreased during the 1990s. This conservation was a result of increased appliance efficiency and more efficient construction standards that followed the major price increases that occurred in the 1970s and 1980s. With limited end uses for natural gas, increasing appliance efficiency, and higher building standards, the downward trend in consumption per customer will continue. Appliance choice will also affect the trend. Customers choosing high efficiency furnaces, energy efficient gas water heaters and electric appliances such as electric water heaters, heat pumps and cooking ranges, will also contribute to the downward trend.

Q. Does this conclude your prepared direct testimony?

A. Yes it does.

COLUMBIA STATEMENT NO. 3

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2016-2529660
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
MELISSA J. BELL
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

Table of Contents

I. Introduction

Q. Please state your name and business address.

A. Melissa J. Bell, 290 West Nationwide Blvd., 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 Regulatory Analyst.

Q. What are your responsibilities as Lead Regulatory Analyst?

A. My responsibilities include providing support for regulatory filings for several NiSource operating companies, including, but not limited to, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"), Columbia Gas of Ohio ("COH"), Columbia Gas of Maryland ("CMD") and Columbia Gas of Massachusetts ("CMA"). The types of filings include quarterly gas cost adjustments, annual uncollectible expense and percentage of income payment plan adjustments, as well as tariff updates. I also provide audit support, rate entry and verification, and other duties as assigned.

Q. What is your educational and professional background?

A. I graduated from The Ohio State University with a Bachelor of Science Degree in Marketing in 1993. I began my career in the energy industry in 1996 when I joined Columbia Gas of Ohio as a Customer Service Representative, before moving on in 1997 to COH's New Business Team as a Project Expediter. In 1999, I left COH for a position at UtiliCorp Energy Solutions as a Commercial Account

Executive, until the sale of UtiliCorp Energy Solutions to Exelon Energy was completed in 2000. At this time, I joined CSC Energy Solutions as a Tariff Analyst until February 2003. In March 2003, I was employed by NiSource in the Gas Transportation Services ("GTS") Department as a GTS Analyst II, providing sales support to Major Account Representatives for Columbia, CMD and Columbia Gas of Virginia ("CGV"), as well as support to Natural Gas Suppliers and their customers. In December 2005, I accepted a position as a Senior Regulatory Analyst in NCSC's Regulatory Strategy and Support Department. I was promoted to my current position as Lead Regulatory Analyst in 2010. I have attended ratemaking workshops provided by the Southern Gas Association, Deloitte LLP, Financial Accounting Institute and Regulatory Research Associates.

Q. Have you previously testified before this or any other regulatory commission?

A. Yes. I have testified once before the Pennsylvania Public Utility Commission ("Commission") in a formal complaint proceeding during my tenure as a GTS analyst. I have also submitted direct testimony in Columbia's previous base rate proceedings, at Docket No. R-2012-2321748 and Docket No. R-2014-2406274, as well as CMD's 2013 base rate proceeding, Case No. 9316 and CMA's 2015 base rate proceeding, D.P.U. 15-50.

Q. What was the nature of the testimony you provided in those proceedings?

A. I prepared and submitted testimony on revenue and rate design proposals.

II. Purpose and Summary of Testimony

Q. Please state the purpose of your prepared direct testimony in this proceeding.

A. I will sponsor and describe exhibits which support Columbia's proposed increase in base rates, as illustrated in Exhibit 102 Schedule 3, Page 3, based on pro forma revenues for the twelve months ending December 31, 2017 (Fully Forecasted Rate Year). The exhibits were compiled in accordance with the Commission's regulations under Title 52 Pennsylvania Code Section 53.51 et. seq., regarding Information Furnished With the Filing of Rate Changes. Specifically, I am responsible for the preparation and presentation of Exhibits 3 and 103 (Operating Revenues), including Exhibit 103 Schedule 8 (Rate Design).

III. Operating Revenues – Exhibit 3

Q. Please explain the process that was undertaken to produce the number of bills used to price revenue in this case.

A. The calculations made to determine the number of bills are found in Exhibit 3, Schedule 2 for the Historic Test Year ("HTY"). Active customer counts for each month of the HTY are accumulated by rate schedule by customer class and shown in Column 1 of Exhibit 3, Schedule 2. The bills are accumulated based on which rate schedule the customer is on at the end of the HTY. Adjustments were made in Exhibit 3 Schedule 2 Column 2 to reflect discontinued or added services for Large Commercial and Industrial customers. Incremental residential and commercial customers that were added or discontinued during the HTY are shown in Column 3 and 4, respectively, for a full year impact. The corresponding backup for customer additions and attrition for the HTY can be found in Exhibit 3, Schedule 5, Pages 1 – 6. Finally, an adjustment is made to the number of bills for final billed customers because a Customer Charge is billed to customers who receive a final bill even though they are not included as an active customer. These customers are not classified as active in the Company's billing systems during the HTY, so the final bills must be added to active bills to price revenue in this case. Bills in Column 8 are used for pricing in Exhibit 3 Schedule 1 (pro forma revenue at present rates) and Exhibit 3, Schedule 10 (pro forma revenue at proposed rates).

Q. Please explain the development of the adjusted volumes in Dekatherm ("Dth") for the HTY.

A. Physical flow volumes were summarized by rate schedule in Exhibit 3, Schedule 3 on a customer-by-customer, and month-by-month basis. The volumes, as shown in Column 1, were accumulated based on the rate schedule the customer was on at November 30, 2015. The Weather Normalization Adjustment ("WNA") in Exhibit 3, Schedule 3, Column 2 represents the change to physical flow volumes due to the use of a 20-year weather definition normalization. Adjustments were made in Exhibit 3, Schedule 3, Column 3 to reflect discontinued or added services for Large Commercial and Industrial customers. Incremental residential and commercial customers that were added or discontinued during the HTY are shown in Columns 4 and 5, respectively, for a full year impact. The corresponding backup for customer additions and attrition for the HTY can be found in Exhibit 3 Schedule 5 Pages 1 – 6.

Q. Please explain why physical flow volumes were used instead of invoiced volumes as the basis for calculating operating revenues.

A. Physical flow volumes were used instead of invoiced volumes because they represent volumes that flowed during the HTY. Invoiced volumes may include adjustments made for prior billing periods that are outside of the HTY. Therefore, physical flow volumes were used to eliminate out of period adjustments.

Q. How is the 20-year weather normalization definition utilized in Exhibit 3, Schedule 4?

A. Company witness Amy L. Efland (Columbia Statement No. 2) provided the total normalized volumes by month for residential and commercial customers. The total normalized volumes were allocated based on the customers' actual physical flow volumes and by their class. Then they were accumulated by rate schedule by rate block, if applicable, as shown in Exhibit 3, Schedule 4, Column 2. The weather adjustment in Column 3 is calculated by subtracting actual physical flow

Dth in Column 1 from the normalized Dth in Column 2. The revenue impact as shown in Column 5 is determined by multiplying the Dth in Column 3 by the current base rates.

Q. Please explain Schedules 6 through 9 of Exhibit 3.

A. Schedules 6 and 7 eliminate certain per book amounts (off system sales revenues, unbilled revenues and unbilled gas costs) that are not relevant to a pro forma calculation of revenues and expenses. Schedules 8 and 9 show the calculated split of per books gas cost, Gas Procurement Charge ("GPC"), Rider USP and Merchant Function Charge ("MFC") and Rider CC by customer class used in reconciling per books revenue to annualized revenue in Exhibit 3 Page 9.

Q. How was pro forma revenue at present rates calculated?

A. As shown in Exhibit 3 Schedule 1, adjusted test year bills from Schedule 2 are shown in Column 1 and adjusted test year Dth from Schedule 3 are shown in Column 2. Present rates are shown in Column 3. Revenue is calculated in Column 4 by multiplying the Customer Charge by number of bills and volumetric rates by volumes. An average rate per Dth is calculated in Column 5 by dividing Column 4 by Column 2. Pro forma revenue at present rates was calculated using the Purchased Gas Cost ("PGC") rate, Rider USP rate and State Tax Adjustment Surcharge ("STAS") in effect as of January 1, 2016, the most recent available at the time the schedules were developed with the exception of the Merchant Function Charge rate (please refer to Exhibit MJB–1, attached to this testimony).

Q. Please explain the adjustment to Forfeited Discounts (Account 487) in Exhibit 3 Page 8.

A. Exhibit MJB-2, attached to this testimony, compares Account 487 revenue to total billed revenue for the three most recent 12 month periods, including the HTY and calculates a three year average. The average of the last three years was selected to match the same basis used by the Company in this rate case to determine an average net write-off rate used for annualization of uncollectible expense. As with net write-offs, Forfeited Discounts historically produce a reasonably predictable percentage of billed revenue over time. A three year average is used to account for the percentage differences caused primarily by changes in gas cost recovery revenue.

The historic three year average percentage of billed revenue is applied to annualized HTY revenue, resulting in annualized historic test year Forfeited Discounts shown on Exhibit MJB-2, page 1. The historic three year average percentage of billed revenue is applied to annualized future test year ("FTY") revenue and annualized fully forecasted rate year ("FFRY") revenue (Exhibit 103), resulting in annualized Forfeited Discounts revenue for those test years shown on Exhibit MJB-2, pages 2 and 3 respectively.

Q. Please explain Exhibit 3 Schedule 10.

A. This schedule calculates pro forma revenues at proposed rates for the HTY reflecting the rate design as shown on Exhibit 103 Schedule 8.

Q. Please explain Pages 6 - 8 of Exhibit 3.

A. The summary shows, by rate schedule by customer class, pro forma test year bills (Column 1), Consumption (Dth) (Column 2), Revenue at Present Rates (Column 3), proposed adjustment (Column 4), and Revenue at Proposed Rates (Column 5). The summary serves as a comparison of revenue at present and proposed rates.

Q. Please explain the "Dth and Revenue Summary at Current Rates" on Page 9 of Exhibit 3.

A. This page summarizes revenue for the HTY by customer class and is the reconciliation of per books revenue to annualized revenue as calculated in Exhibit 3, Schedule 1. Exhibit 3, Page 9, Column 1 reflects the per books revenue as of November 30, 2015. Columns 2 through 6 show the calculated split of per books gas cost, Rider USP, GPC, MFC and Rider CC by customer class calculated on Exhibit 3, Schedules 8 and 9. The weather adjustment calculated on Exhibit 3, Schedule 4 is shown in Exhibit 3, Page 9, Column 8. Column 9 reflects pricing out the test year billing determinants (bills and volumes) at the most current base rates. Column 10 is the pro forma Delivery Service revenue at current rates calculated on Exhibit 3, Schedule 1.

Q. Please explain the "Dth and Revenue Summary at Current Rates" on Page 10 of Exhibit 3.

A. This page summarizes annualized total revenue at present rates as calculated on

Exhibit 3 Schedule 1. Column 1 shows pro forma Delivery Service revenue at present rates. Column 2 shows a summary of gas costs at present rates in effect as of January 1, 2016. Column 3 shows a summary of Rider USP at present rates in effect as of January 1, 2016. Column 5 shows a summary of the Merchant Function Charge. Detailed calculations by rate schedule for Columns 1 through 6 are shown in Exhibit 3, Schedule 1. Column 7 shows total revenue at present rates.

IV. <u>Operating Revenues – Exhibit 103</u>

Q. Please describe the projection of bills for the Future Test Year and Fully Forecasted Rate Year.

A. Forecasted active customer counts are first determined on a total company basis by customer class by type of service (sales/Choice transportation/non-Choice transportation) by month in the Company's forecast model supported by Company witness Efland (Columbia Statement No. 2) on Exhibit 10, Schedule 2. The customer counts are then spread for each month of the FTY and the FFRY, based on the HTY experience, by rate schedule by customer class by type of service for Residential and small Commercial sales and Choice customers. The bills are accumulated based on which rate schedule the customer is on at the end of the HTY and the results are shown in Exhibit 103, Schedule 2, Column 1.

Adjustments resulting from Large Commercial or Industrial customers that are expected either to discontinue or to add service during the FTY and FFRY are shown by customer in Exhibit 103, Schedule 4, Pages 16 and 18 respectively, and summarized in Exhibit 103, Schedule 2, Column 2. New construction customers who are expected to begin service during the FTY and FFRY are shown on Exhibit 103, Schedule 4, Pages 1 and 7 respectively and summarized on Exhibit 103, Schedule 2, Column 3. Customer attrition, which is expected to occur during the FTY and FFRY is shown on Exhibit 103, Schedule 4, Pages 3 and 9, respectively, and summarized on Exhibit 103, Schedule 2, Column 4. Column 5 of Exhibit 103, Schedule 2 reflects the shifts between rate schedules that occurred during the test year. The Company considers the HTY final bill count to be representative of what can be expected during the FTY and FFRY. Therefore, the HTY final billed count was added to the forecasted active bills to price revenue in this case. Final bill counts are shown in Exhibit 103, Schedule 2, Column 6. FTY adjusted number of bills in Exhibit 103, Schedule 2, Column 7 is the sum of Columns 1 through 6. Bills in Column 7 are used for pricing in Exhibit 103, Schedule 1 (pro forma revenue at present rates) and Exhibit 103, Schedule 7 (pro forma revenue at proposed rates) for both the FTY and the FFRY.

Q. Please explain the process used to develop Future Test Year and Fully Forecasted Rate Year Dth.

A. Forecasted adjusted Dth for both the FTY and the FFRY are shown in Exhibit 103, Schedule 3, Column 6 are the sum of: (a) forecasted Dth in Exhibit 103, Schedule 3, Column 1, (b) Large Commercial and Industrial adjustments in

Exhibit 103, Schedule 3, Column 2, (c) new construction consumption in Exhibit 103, Schedule 3, Column 3, (d) attrition consumption in Exhibit 103, Schedule 3, Column 4, and (e) rate schedule transfers in Exhibit 103, Schedule 3, Column 5. Volumes in Exhibit 103, Schedule 3, Column 6 are used for pricing in Exhibit 103, Schedule 1 (pro-forma revenue at current rates) and Exhibit 103, Schedule 7 (pro-forma revenue at proposed rates) for both the FTY and FFRY.

Forecasted Dth are first determined by customer class, by type of service (sales/Choice transportation/non-Choice transportation), by month in the Company's forecast model supported by Company witness Efland in Exhibit 10 Schedule 2. These Dth are spread for each month of the FTY and FFRY based on the HTY by rate schedule, by customer class, by type of service for Residential and Small Commercial Sales and Choice customers. The spread for Large Commercial and Industrial Sales and Choice transportation cusomtersand all non-Choice transportation customers is performed down to the individual customer level. The Dth are accumulated based on which rate schedule the customer is on at the end of the HTY and shown in Column 1 of Exhibit 103, Schedule 3.

Adjusted Dth in Exhibit 103, Schedule 3, Column 6 are the sum of Columns 1 through 5 for both the FTY and FFRY. Adjustments resulting from Large Commercial and Industrial customers either discontinuing or adding service during the FTY and FFRY are shown by customer in Exhibit 103, Schedule 4, Page 16 and 18, respectively, and summarized in Exhibit 103, Schedule 3, Column 2 for reasons I explained previously, with respect to customer bills. Consumption calculated for new construction customers who are expected to begin service during the FTY are shown on Exhibit 103, Schedule 4, Pages 10 and 11 and Pages 14 and 15 for the FFRY. The Dth attributable to new customers are summarized on Exhibit 103, Schedule 4, Page 2, Column 1 and are shown on Exhibit 103, Schedule 3, Column 3. Customer attrition, which is expected to occur during the FTY and FFRY is calculated on Exhibit 103, Schedule 4, Pages 3 and 9, respectively, and is shown on Exhibit 103, Schedule 3, Column 4.

Q. Please explain Exhibit 103, Schedule 7.

A. This Schedule calculates pro forma revenues at proposed rates for the FTY and FFRY, respectively, reflecting the rate design as shown on Exhibit 103, Schedule 8.

Q. Please explain Pages 6 - 9 of Exhibit 103.

A. The summary shows, by rate schedule by customer class, pro forma test year bills (Column 1), Consumption (Dth) (Column 2), Revenue at Present Rates (Column 3), proposed adjustment (Column 4), and Revenue at Proposed Rates (Column 5). The summary serves as a comparison of revenue at present and proposed rates.

Q. Please explain the "Dth and Revenue Summary at Current Rates" on Pages 10 through 15 of Exhibit 103.

A. These pages summarize annualized total revenue at present rates as calculated on Exhibit 103, Schedule 7. Exhibit 103 includes annualized total revenue for both the FTY and FFRY.

Q. Please summarize the drivers that make up the difference in revenue in Exhibit 103 between the FTY and the FFRY.

A. The difference between the revenue in the FTY and the FFRY year is driven by changes in customer growth, attrition, declining use per customer, expected changes in customer counts, and usage for large customers based upon a customer by customer review. See Witness Efland's testimony for an explanation of the drivers as reflected in her forecast model.

V. <u>Principles of Revenue Allocation and Rate Design</u>

Q. Please describe the rate design principles that the Company considered when developing the proposed rates.

A. The principles used to develop the Company's rate design include: efficiency, simplicity, continuity or gradualism, fairness, and earnings stability. An efficient rate design provides accurate price signals and thus, an accurate basis for consumers' decisions. Further, an efficient design provides the Company with a reasonable opportunity to recover the cost of providing service. A simple rate structure is one that is understood by customers. The goal of rate continuity seeks gradual changes to rate design that will allow customers to adjust their consumption patterns, as needed. A fair rate design will consider the results of the allocated cost of service ("ACOS") study in determining rate classes' total revenue responsibility. Finally, earnings stability means that the Company's earnings resulting from its rates should not vary significantly over the period of a few years.

VI. Revenue Allocation

Q. Please state the basis for the Company's proposed rate design.

A. Consistent with the goal of continuity, Columbia seeks to move base rates closer to the ACOS study gradually, so as to avoid rate shock to any particular rate class. This is true for all rate classes except for LDS/LGSS, which I will discuss later in my testimony. The cost to serve each rate class is defined through the ACOS.

Q. How were the results of the ACOS study used in designing the proposed revenue requirements and rates?

A. The cost allocation studies were used as a guide for assigning additional revenue responsibility to rate classes. As discussed in the testimony of Company witness Balmert (Columbia Statement No. 11), Columbia recognizes that no one ACOS study is the "right" study. Therefore, the Company relies on a combination of different studies, namely, the Customer/Demand and Peak & Average studies, to provide a reasonable range of returns for use as a guide in establishing appropriate rates. The Mid-Point or Average study is an average of the results of the Peak & Average and Customer/Demand methodologies and presents the most reasonable and appropriate basis for the assignment of revenue responsibility to the Company's customer base.

Q. What are the results of the ACOS studies?

A. Exhibit MJB-3 shows the class-level returns and return indices for each of the ACOS studies at present rates. Return indices compare individual class returns to the overall Company return. A return index is calculated by dividing the class return by the total Company return, then multiplying the result by 100 to produce the index. The total Company return will always be 100. The closer an individual class return is to the total Company return, the closer its index will be to 100 and to parity. "Parity" in this context means that the class return and the total Company return are equal.

Columbia's largest class is the residential class representing, on an adjusted basis, approximately 73% of total Company revenues and 91% of total Company customers. The return index for the residential class ranges from 75.2 under the Customer/Demand study to 108.8 under the Peak & Average study. The average ACOS study produces a residential return index of 90.5, indicating that the class returns are somewhat below parity at present rates. In developing the proposed rates for the residential class, Columbia sought to increase the revenue requirement of the residential class to move toward parity with the overall total Company return. Columbia proposes to increase the unitized return from the current 0.90477 to .95500, a 5.6% increase toward parity.

The SGSS1/SCD1/SGDS1 (< 6,440 therms annually) return indices are 100.4 for the Peak & Average study, 109.4 for the Customer/Demand study, and 104.8 for the average ACOS study, indicating that the class returns are somewhat above parity at present rates. In developing the proposed rates for the SGSS1/SCD1/SGDS1 (< 6,440 therms annually) class, I looked at the current unitized return. The class's return is 1.04820, which is above parity with total Company; therefore, Columbia is proposing to apportion less of an increase to the SGSS1/SCD1/SGDS1 class so that the unitized returns drop to 1.00374, which is a gradual approach toward parity.

The SGSS2/SCD2/SGDS2 (> 6,440 and less than or equal 64,400 therms annually) return indices are 100.4 for the Peak & Average study, 109.4 for the Customer/Demand study, and 104.8 for the average ACOS study, indicating that the class returns are somewhat above parity at present rates. In developing the proposed rates for the SGSS2/SCD2/SGDS2 (> 6,440 and less than or equal to 64,400 therms annually) class, I looked at the current unitized return. The class's return is 1.41804, which is above parity with total Company; therefore, Columbia is proposing to apportion less of an increase to the SGSS2/SCD2/SGDS2 (> 6,440 and less than or equal to 64,400 therms annually) class so that the unitized returns drop to 1.24073, which is a gradual approach toward parity.

The SDS/LGSS return indices are 104.0 for the Peak & Average study, 256.3 for the Customer/Demand study, and 158.5 for the average ACOS study, indicating that the class returns are somewhat above parity at present rates. In developing the proposed rates for the SDS/LGSS class, I looked at the current unitized return. The class's return is 1.58482, which is above parity with total Company; therefore, Columbia proposes to apportion less of an increase to the SDS/LGSS class, so that the unitized returns drop to 1.36482, which is a gradual approach toward parity and in line with both the SGSS1/SCD1/SGDS1 and SGSS2/SCD2/SGDS2 rate classes that are to a lesser extent, currently above parity.

The LDS/LGSS return indices are 27.9 for the Peak & Average study, 284.3 for the Customer/Demand study, and 88.7 for the average ACOS study, indicating that the class returns are somewhat below parity at present rates. In developing the proposed rates for the LDS/LGSS class, I looked at the current unitized return for the class. The class's return is 0.8868, which is below parity with total Company. Normally I would assign an increase to the LDS/LGSS class that would move the class closer to parity, however, because approximately 24% of the revenue generated for this class is generated from LDS/LGSS customers who flex down from the current LDS/LGSS rates and therefore cannot contribute anymore toward the LDS/LGSS revenue requirement, the impact to the remaining non-flex LDS/LGSS customers would have been unduly excessive. Therefore, in the interest of fairness, I limited the increase to the LDS/LGSS class so that the non-flex customers receive a base revenue increase of 16.44%, which is essentially the same as the increase to the Residential class base revenue increase at 16.48%. The return for the Main Line Distribution Service ("MLDS")/Negotiated Sales Service ("NSS") classes indicates that, by directly assigning mains investment, the return is the same under each of the three ACOS studies showing a return that is above parity with a return index of 1,650.8 at present rates. I note that the MLDS class is unique, in that all customers are located on, or near interstate pipelines. The Company has historically, and in this case continues to, directly assign distribution plant based on an actual inventory of investment to the rate class (See Statement No. 11). Rates for the class, and the customers served under the rate class have not changed for some period of time. In developing the proposed rates for the MLDS/NSS class, I looked at the current unitized return. Because the class's return is 16.50823, which is materially above parity with total Company Columbia proposes no increase in revenue requirement to the MLDS/NSS class, so that the unitized returns drop to 12.06018, which is a gradual approach toward parity.

Q. What is the primary goal of Columbia's class revenue allocation?

A. The primary goal in Columbia's approach to revenue allocation is to maintain a movement toward parity among the various rate classes, consistent with Commission decisions in previous Company rate cases. Movement toward parity is a way of assuring that the revenue allocation process takes into account the overall Company return and the relative returns by rate class. Each class's revenue increase is determined within the context of other rate class returns so that, over time, interclass returns remain close to one another rather than diverging. Maintaining a movement toward parity is a way to reduce potential cross-subsidization between classes.

Q. Do the Company's proposed rate increases for the various rate classes reflect the principle of gradualism?

A. Yes, in two ways. First, with the exception of the LDS/LGSS class, the Company's proposed rate increases for the various rate classes cause a movement of the unitized returns toward parity (unitized return of 1.00000) for each of the rate classes but with no rate class yet reaching parity. Secondly, the range of base rate revenue increase percentages (excluding the MLDS class) is 10.88% to 16.48% where the system average is 15.31% (see Exhibit 103, Schedule No. 8, Page 1, Lines 19 through 35).

Q. Please describe the Company's proposed revenue allocation.

A. Columbia's allocation of the proposed base rate revenue increase, which is shown in Exhibit 103, Schedule No. 8, Page 5, Line 19 reflects the following allocations: 78.15 % of the overall increase is applied to the residential class; 7.75 % of the overall increase is applied to the SGSS1/SCD1/SGDS1 class with annual usage less than 6,440 therms; 6.80 % of the overall increase is applied to the

SGSS2/SCD2/SGDS2 class with annual usage between 6,440 therms and 64,400 therms; 3.35 % of the overall increase is applied to the SDS/LGS class; 3.95 % of the overall increase is applied to the LDS/LGS class; and none of the overall increase is applied to MLDS/NSS customers. As a result, the proposed unitized return for the residential class will be .95500, or 95.5 %, as compared to the overall total Company unitized return of 1.00000 or 100 %, an increase of 5.5 %. This percentage increase recognizes that the current residential return is lower than the overall return. Similarly, the SGSS1/SCD1/SGDS1 class (< 6,440 therms annually) would receive a 9.6 % decrease in unitized return, the SGSS2/SCD2/SGDS2 class (> 6,440 and less than or equal to 64,400 therms annually) would receive a 12.5% decrease in the unitized return, the SDS/LGSS class would receive a 13.9 % decrease in unitized return, and the LDS/LGSS class would receive a 7.7 % decrease in unitized return, which brings all classes except for LDS/LGSS closer to parity with the overall return, as measured by the results of the Average ACOS Study. The MLDS/NSS class would receive a 26.9 % decrease in unitized return, as a result of assigning no increase to the class. I note that for all classes the allocated increases and resulting unitized returns fall within the zone of reasonableness bounded by the Peak & Average and Customer Demand Studies.

Exhibit 103, Schedule 8, Page 5, Lines 4 through 6 shows the movement toward parity produced by Columbia's proposed revenue allocation using the average

ACOS Study. The movement toward parity (unitized return of 1.00000) measures each class's return versus the total Company return under current and proposed rates.

VII. Rate Design

Q. Other than the ACOS studies, what guidelines or criteria have you considered in the design of the Company's rates?

A. There are a number of criteria that I considered in the design of rates, including the following:

- First, the design of Columbia's rates recognizes that rates must be just and reasonable and must not be unduly discriminatory. Columbia's proposed rate design also attempts to minimize cross-class subsidies.
- Second, where rates require adjustment to achieve proper cost recovery, customer impact considerations have been factored into the rate design process. For instance, Columbia's proposed rate design moves each of the rate classes toward parity (unitized return of 1.00000 and a total Company required rate of return of 8.150 %) but recognizes a move to full parity of 1.00000 in this case would not be consistent with the principle of gradualism.
- Third, Columbia's proposed rate design provides for recovery of an increasing proportion of fixed costs through the Customer Charge. This objective recognizes that the historical recovery of fixed costs through the

volumetric rate portion of the rate schedule inevitably results in the over or under recovery of those costs because the revenues generated from customers' volumetric use of gas can be greatly sensitive to customer usage fluctuations that vary due to conservation efforts or other changing consumption characteristics. In essence, customer-related costs that bear no relationship to customer gas consumption patterns should be recovered through the fixed portion of the rate design, i.e. the monthly Customer Charge. Columbia's proposed rate design thus recovers a gradual increase in the fixed costs recovered through the Customer Charges for each of the rate classes.

Q. Why does the Company propose an increase in the percentage of base rate recovery through the Customer Charge now that Columbia has a WNA mechanism?

A. The WNA normalizes the impact of weather on the recovery of residential usage based base revenue (outside a 5% band) during the months when the WNA is in effect. In doing so, the WNA affords the Company a greater opportunity to recover its authorized revenue requirement from its residential customer, while mitigating the impact of weather on the level of revenues collected from them. Thus, the WNA mechanism is beneficial to both Columbia and its customers. The WNA does not address usage fluctuations that are a result of conservation efforts or other changing consumption characteristics, intra-class subsidization of fixed cost recovery, weather effects of consumption outside the seven winter months that the WNA is in effect, the weather effects of consumption within the 5% WNA band, or weather effects of consumption for rate classes not covered by the WNA. Therefore, it is important for the Customer Charges to recover an increased percent of the fixed costs included in base rate revenue recovery.

Q. How are proposed changes in the Company's Customer Charges determined?

A. The Company's proposal for rates in this case is to increase the current Customer Charge for each class by the class' percentage of base revenue allocation as shown on Exhibit 103, Schedule 8, Page 1, Column 7, lines 20 through 34, the exceptions being the two SGS/SCD/SGDS classes and the MLDS rate class. The Company proposes to keep the current Customer Charge for the SGS1/SCD1/SGDS1 (< 6,440 therms annually) class. The Company proposes to bring the Customer Charge for the SGS2/SCD2/SGDS2 (> 6,440 and less than 64,400 therms annually) class to the minimum Customer Charge as supported by witness Balmert's Customer Charge study, Exhibit 111, page 25, line 37. The Company proposes no increase to the MLDS Customer Charges, because the Company proposes no increase in revenue requirement to the MLDS class.

Q. Please explain the rationale for increasing Customer Charges to reflect the recovery of a proportion of fixed non-gas costs.

A. It is reasonable and appropriate to collect a proportion of fixed non-gas costs through the fixed monthly Customer Charge. For example, for Columbia, just over 32.5% of its delivery charge revenue is currently recovered through Customer Charge to its residential customers. Even with a proposed increase in the Customer Charge, the residential percentage increases slightly to 32.8% of distribution charge revenue and will remain below the average of the last six rate cases of 37.1% (See Exhibit MJB-4). Fixed cost recovery through the fixed monthly Customer Charge decreases the likelihood and magnitude of customers' over- or under-payments for distribution service each month due to usage fluctuations, recognizing that a natural gas utility's customer-related costs do not vary with gas usage. Even after the proposed changes to existing Customer Charges for each of the rate classes, all of the Customer Charges are in the range of the Customer Charges that support the cost of minimum system cost-based Customer Charges shown on Exhibit 111, Schedule 1, Pages 16 and 25, Line 41 and Line 37, respectively. All rates except for the MLDS rate class are at or below the average of the last six rate cases' percentage of fixed cost recovery (See Exhibit MJB-4), and not increase to the MLDS customer charges is proposed.

Q. What are the benefits of increasing the proportion of fixed non-gas costs recovered through the monthly Customer Charge to Columbia and its customers?

A. In addition to the decreased likelihood and magnitude of customers' over- or under-payments for delivery service discussed previously, there are a number of other significant benefits resulting from an increase to the proportion of fixed non-gas costs recovered through the monthly charge. These benefits include: increased stability and predictability of customers' bills, greater simplicity and understandability of customers' bills, a corresponding reduction in bill complaints, and mitigation of intra-class cross subsidization. Additionally, the increased reliance on Customer Charges for fixed cost recovery should reduce the magnitude of annual true-ups for customers participating in Columbia's budget payment plan.

Q. Please summarize Columbia's residential rate design proposal.

A. Columbia proposes an increase to the Residential Customer Charge from the current $16.75 per month to a $19.51 per month charge. The percentage increase to the Customer Charge is in proportion to the overall percentage increase proposed to the residential rate class of 16.46% shown in Exhibit 103, Schedule 8, Page 1, Line 20, Column 7. It should be noted that $19.51 is between the $18.79 and $43.82 minimum system cost-based Customer Charges shown in the ACOS study (Exhibit 111, Schedule 1, Page 16, Line 41 and 25, Line 37). It should also be noted that the Company currently only recovers 32.5% of its residential distribution costs through the Customer Charge. Even with a $2.76 increase in the residential Customer Charge, the percentage only increases to 32.8%, which is still below the last six rate case average of 37.1%. Finally, it should be noted that Columbia has no decoupling mechanism to ensure a reasonable opportunity to recover cost of service. Therefore, the Company relies on the Customer Charge for protection from usage erosion due to customers switching to more efficient furnaces and appliances and Columbia's energy efficiency program.

Q. Will Customer Assistance Program ("CAP") customers receive a rate increase as a result of this rate proceeding?

A. For rate design purposes, Columbia anticipates that current CAP customers will not receive an increase in their required payment, and thus the revenue increment that is assigned to CAP customers will be collected from other residential customers through the Rider USP.

Q. Please summarize Columbia's SGSS/SCD/SGDS rate design proposal.

A. The Company proposes to keep the Customer Charge for the SGSS1/SCD1/SGDS1 (< 6,440 therms annually) at $21.25. The cost to serve the SGSS1/SCD1/SGDS1 class is similar to the cost to serve the residential rate class and therefore rate designs of the two rate classes should move toward similarity. At $21.25, the volumetric base rate will be $4.3189/Dth for SGSS1/SCD1 service and $4.1822/Dth for SGDS1 service. The proposed SGSS2/SCD2/SGDS2 Customer Charge for customers whose usage is between 6,440 therms and 64,400 therms is $57.46, which is $9.46 more than the current $48.00. With the increase in the Customer Charge, the percentage of distribution costs recovered through the

Customer Charge will only increases to 11.5% from the current 10.7%, which is still below the last six rate case average of 20.3%. The volumetric charge will be $3.6055/Dth for SGSS/SCD service and $3.469/Dth for SGDS service.

Q. Do the two SGSS, SCD, and SGDS rate classes split the volumetric base rate between what is charged to SGSS and SCD customers from what is charged to SGDS customers?

A. Yes. In the past three base rate proceedings, the Company re-allocated the storage working capital costs assigned to the SGSS/SCD/SGDS classes as a whole through the ACOS to SGSS/SCD classes only. Per the approved settlement in Docket No. R-2012-2321748, Columbia agreed to re-allocate $530,000 of storage working capital costs from SGDS to SGSS/SCD. Per the approved settlement in Docket No. R-2014-2406274, Columbia agreed to re-allocate $710,000 of storage working capital costs from SGDS to SGSS/SCD. Per the approved settlement in Docket No. R-2015-2468056, Columbia agreed to re-allocate $597,433 of storage working capital costs from SGDS to SGSS/SCD. As part of this current proceeding, and as explained by Company witness Balmert in testimony and shown on Exhibit MPB-4, the Company has re-allocated $306,121 of storage working capital costs from the SGDS class to SGSS/SCD. This intra-class re-allocation is shown on Line 17 of Exhibit 103, Schedule 8, Page 7 and Line 17 of Page 8. As a result, the Company charges a different volumetric base rate to the

SGSS and SCD customers than to the SGDS customers and that principle will not change under proposed rates.

Q. Please summarize Columbia's SDS/LGSS rate design proposal.

A. The proposed SDS/LGSS Customer Charge for customers whose usage is between 64,400 therms and 110,000 therms is $238.39. The $238.39 is $23.39 more than the current SDS/LGSS Customer Charge of $215.00. With the increase in the Customer Charge, the percentage of distribution costs recovered through the Customer Charge will remain the same at 17.1%, which is slightly higher than the last six rate case average of 16.7%.

The proposed SDS/LGSS Customer Charge for customers whose usage is between 110,000 therms and 540,000 therms is $759.53. The $759.53 is $74.53 more than the current SDS/LGS Customer Charge of $685.00. The volumetric base rate will be $2.3073/Dth for SDS/LGSS customers whose usage is between 64,400 therms and 110,000 therms and $2.1572/Dth for SDS/LGSS for customers whose usage is between 110,000 therms and 540,000 therms. The percentage increase to the SDS/LGSS Customer Charges are in proportion to the overall percentage increase proposed to the SDS/LGSS rate class of 10.87% shown in Exhibit 103, Schedule 8, Page 1, Line 31, Column 7.

Q. Please summarize Columbia's LDS/LGSS rate design proposal.

A. The proposed LDS/LGSS Customer Charge for customers whose usage is between 540,000 therms and 1,074,000 therms is $2,096.28, an increase of $296.28 over the current Customer Charge of $1,800.

The proposed LDS/LGSS Customer Charge for customers whose usage is between 1,074,000 therms and 3,400,000 therms is $3,260.88. The $3,260.88 is $460.88 more than the current LDS/LGS Customer Charge.

The proposed LDS/LGSS Customer Charge for customers whose usage is between 3,400,000 therms and 7,500,000 therms is $6,288.84. The $6,288.84 is $888.84 more than the current LDS/LGSS Customer Charge of $5,400.

The proposed LDS/LGSS Customer Charge for customers whose usage greater than 7,500,000 therms is $9,316.80. The $9,316.80 is $1,316.80 more than the current LDS/LGSS Customer Charge of $8,000.

The percentage increase to the LDS/LGSS Customer Charges are in proportion to the overall percentage increase proposed to the LDS/LGSS rate class of 16.44% shown in Exhibit 103, Schedule 8, Page 1, Line 24 Column 7.

With the proposed increase in the LDS Customer Charges, the percentage of distribution costs recovered through the Customer Charge remains the same at 17.0%, which is still below the last six rate case average of 17.2%.

Q. How is the LDS/LGSS volumetric based rate revenue requirement shown in Exhibit 103, Schedule 8, Page 9, Line 28 spread among the LDS/LGSS annual usage groups?

A. Volumetric Base Rate Revenue requirement is split among the LDS/LGSS annual usage groups proportionately based on revenue produced from current volumetric Base Rates. (See Exhibit 103, Schedule 8, Page 9, Lines 30 through 33).

Q. Please discuss the rate design proposals for the MLDS/NSS class.

A. Columbia is proposing no change to the Customer Charges or volumetric charges.

Q. Please discuss the rate design proposals for the Main line Sales Service ("MLSS") class.

A. MLSS service applies to the same customer groups that MLDS service applies to with the primary exception that MLSS service is a sales service and MLDS service is a distribution service. There were no MLSS customers served by the Company during the HTY, nor are there any MLSS customers expected to take service during the forecasted rate year. However, the MLSS tariff is active and it is the Company's intent that customers who elect to be served under the MLSS tariff pay the same distribution service rates established for the MLDS tariff customers in this case.

Q. Please describe the treatment of flex rate agreements in the development of the Company's base rates.

A. Revenues resulting from flex rate agreements are shown by rate class in Exhibit No. 103, Schedules 1 and 7. Because the flex agreements are individually negotiated, the associated revenues are not increased as a result of the Company's rate case filing.

Q. Do flex rate agreements benefit Columbia's non-flex customers?

A. Yes. Revenue collected from flex rate customers contributes to the recovery of the Company's fixed costs. Absent flexed rates, the Company expect sit would lose these customers to alternatives. Without the revenues from the flex customers, non-flex customers would be assigned additional fixed cost recovery responsibility and their rates would increase.

VIII. Revenue Proof and Bill Impacts

Q. Please provide a proof of the FTY base revenue requirement by rate schedule.

A. Please refer to Exhibit 103, Schedule 8.

Q. Please summarize the class-level bill impacts resulting from the Company's proposal.

A. The class average bill impacts are shown on Exhibit No. 103, Schedule 8, Page 1, column 7.

Q. Is the Company providing graphs of the bill impacts?

A. Yes. Please refer to Exhibit No. 111, Schedule No. 5, Pages 1 – 9. A graph for Residential Sales Service is shown on Page 1. Pages 2 through 9 provide graphs for Small General Sales Service and Large General Sales Service.

Q. What is the range of monthly bill impacts for residential customers?

A. Please refer to Exhibit No. 111, Schedule No. 6, Page 1. This schedule shows monthly bill impacts for residential customers at various usage levels.

Q. Has the Company performed bill impact analyses for commercial and industrial customers?

A. Yes. Please refer to Exhibit No. 111, Schedule No. 6, Pages 2-9. These schedules provide monthly bill impacts for Small General Sales Service and Large General Sales Service customers at various usage levels.

Q. Does this complete your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc
Calculation of Merchange Function Charge Utilized in Exhibit No 3 and Exhibit No 103
Calculated Using Gas Costs as of January 1, 2016

Line No.	Description	Reference	Rate $	
1	PGCC Rate	Exhibit 1-A, Schedule 1, Page 1, Col 3, Line 5 (1/01/16 Quarterly GCR Filing)	2 7354	
2	Total Commodity Cost of Gas		**2.7354**	per Dth
3	Residential Uncollectible Expense Ratio[1]	Exhibit No 4, Schedule No 2, Page 32, Line 7	0 0152	
4	Non-Residential Uncollectible Expense Ratio[1]	Exhibit No 4, Schedule No 2, Page 32, Line 14	0 0037	
5	Merchant Function Charge - Residential Sales Service	(Line 4 x Line 5)	0 0416	per Dth
6	Merchant Function Charge - Small General Sales Service	(Line 4 x Line 6)	0 0102	per Dth

[1] Per Order in Docket No R-2012-2321748

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending November 30, 2015

Line No.		12 Mos November 2013	12 Mos November 2014	12 Mos November 2015	Total 3 Year Average	
1	Per Books Acct 487	$ 1,144,228	$ 1,321,479	$ 1,289,914	$ 3,755,621	
2	Per Books Billed Revenue	$ 446,111,765	$ 542,904,735	$ 553,848,611	$ 1,542,865,111	
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2565%	0.2434%	0.2329%	0.2434%	
4	Historic Test Year Sales Revenue (Ex. 3, Page 10, Line 6)					$ 335,452,815
5	Historic Test Year Revenue -Transportation Revenue (Ex. 3, Page 10, Line 9)					$ 148,307,734
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$ 483,760,549
7	3 Year Average					0.2434%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$ 1,177,473
9	Historic Test Year Acct 487 (Ex 3, Page 9)					$ 1,289,914
10	Annualization Adjustment (Line 8 - Line 9)					$ (112,441)

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending November 30, 2016

Line No.		12 Mos November 2013	12 Mos November 2014	12 Mos November 2015	Total 3 Year Average	
1	Per Books Acct 487	$ 1,144,228	$ 1,321,479	$ 1,289,914	$ 3,755,621	
2	Per Books Billed Revenue	$ 446,111,765	$ 542,904,735	$ 553,848,611	$ 1,542,865,111	
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2565%	0.2434%	0.2329%	0.2434%	
4	Future Test Year Sales Revenue (Ex. 103, Page 11, Line 5)					$ 340,685,153
5	Future Test Year Transportation Revenue (Ex. 103, Page 11, Line 8)					$ 147,560,925
6	Total Sales and Transportation Revenue (Line 4 + Line 5)					$ 488,246,078
7	3 Year Average					0.2434%
8	Annualized Forfeited Discounts (Line 4 * Line 6)					$ 1,188,391
9	Future Test Year Acct 487 (Ex. 103, Page 10)					$ 1,177,473
10	Annualization Adjustment (Line 7 - Line 8)					$ 10,918

Columbia Gas of Pennsylvania, Inc.
Annualization of Forfeited Discounts (Account 487)
For the Twelve Months Ending December 31, 2017

Line No.		12 Mos November 2013	12 Mos November 2014	12 Mos November 2015	Total 3 Year Average		
1	Per Books Acct 487	$ 1,144,228	$ 1,321,479	$ 1,289,914	$ 3,755,621		
2	Per Books Billed Revenue	$ 446,111,765	$ 542,904,735	$ 553,848,611	$ 1,542,865,111		
3	Forfeited Discounts as a % of Revenue (Line 1 / Line 3)	0.2565%	0.2434%	0.2329%	0.2434%		
4	Fully Forecasted Rate Year Sales Revenue (Ex 103, Page 15, Line 5)					$	342,152,680
5	Fully Forecasted Rate Year Transportation Revenue (Ex. 103, Page 15, Line 8)					$	148,310,352
6	Total Sales and Transportation Revenue (Line 5 + Line 6)					$	490,463,032
7	3 Year Average						0.2434%
8	Annualized Forfeited Discounts (Line 7 * Line 6)					$	1,193,787
9	Fully Forecasted Rate Year Acct 487 (Ex.10 3, Page 14)					$	1,188,391
10	Annualization Adjustment (Line 8 - Line 9)					$	5,396

Columbia Gas of Pennsylvania, Inc.
Cost of Service Study Results
For the 12 Months Ending December 31, 2017

	Peak & Average		Customer/Demand		Average Study	
	Return	Index	Return	Index	Return	Index
Residential Service (RS/RDS)	6.482%	108.9	4.482%	75.3	5.389%	90.5
Small General Service (SGSS/SCD/SGDS) (< 6,440 therms annually)	5.981%	100.4	6.514%	109.4	6.241%	104.8
Small General Service (SGSS/SCD/SGDS) (> 6,440 and ≤ 64, 400 therms annually)	5.975%	100.3	12.308%	206.7	8.444%	141.8
Small Distribution Service (SDS/LGSS)	6.193%	104.0	15.261%	256.3	9.437%	158.5
Large Distribution Service (LDS/LGSS)	1.661%	27.9	16.929%	284.3	5.281%	88.7
Mainline Distribution Service (MLDS)	98.301%	1,650.7	98.301%	1,650.7	98.301%	1,650.7
Total Company	5.955%	100.0	5.955%	100.0	5.955%	100.0

Columbia Gas of Pennsylvania, Inc
Base Rate Cost Recovery
For the 12 Months Ending December 31, 2017

	2008	2010	2011 2/	2012	2014	2015	6 Case Average 3/	Proposed 2016	Difference
Residential Service (RS/RDS)									
Customer Charge Revenue	52,191,199	55,804,410	85,183,066	77,259,358	78,381,874	79,308,588		92,376,747	
Base Rate per Dth Revenue	86,046,002	84,572,528	64,221,831	116,137,004	142,844,682	164,470,180		188,584,659	
Total Base Rate Recovery	138,237,201	140,376,938	149,404,897	193,396,362	221,226,556	243,778,768		280,961,406	
Customer Charge Recovery Percent of Total	37 755%	39 753%	57.015%	39.949%	35.431%	32.533%	37 084%	32 879%	-4 205%
Small General Service (SGSS1/SCD1/SGDS1) 1/									
Customer Charge Revenue	8,251,948	8,656,237	9,598,846	10,305,040	11,089,775	7,935,600		7,935,600	
Base Rate per Dth Revenue	33,800,244	26,943,030	27,287,894	36,944,451	44,105,641	21,066,665		25,336,204	
Total Base Rate Recovery	42,052,192	35,599,267	36,886,740	47,249,491	55,195,416	29,002,265		33,271,804	
Customer Charge Recovery Percent of Total	19.623%	24 316%	26 022%	21.810%	20.092%	27 362%	23 204%	23 851%	0 647%
Small General Service (SGSS2/SCD2/SGDS2) 1/									
Customer Charge Revenue	8,251,948	8,656,237	9,598,846	10,305,040	11,089,775	3,480,768		4,166,770	
Base Rate per Dth Revenue	33,800,244	26,943,030	27,287,894	36,944,451	44,105,641	29,155,815		32,220,500	
Total Base Rate Recovery	42,052,192	35,599,267	36,886,740	47,249,491	55,195,416	32,636,583		36,387,270	
Customer Charge Recovery Percent of Total	19 623%	24 316%	26.022%	21 810%	20.092%	10 665%	20 421%	11 451%	-8 970%
Small Distribution Service (SDS/LGSS) 1/									
Customer Charge Revenue	1,502,080	1,567,843	1,777,454	2,112,274	2,302,200	2,863,650		3,175,216	
Base Rate per Dth Revenue	7,455,074	7,561,578	7,743,183	12,199,753	12,356,098	13,857,949		15,391,886	
Total Base Rate Recovery	8,957,154	9,129,421	9,520,637	14,312,027	14,658,298	16,721,599		18,567,102	
Customer Charge Recovery Percent of Total	16 770%	17 174%	18.669%	14 759%	15.706%	17 125%	16 701%	17 101%	0 400%
Large Distribution Service (LDS/LGSS) 1/									
Customer Charge Revenue	1,398,392	1,343,244	1,436,538	1,671,952	1,714,800	2,250,000		2,620,351	
Base Rate per Dth Revenue	6,102,827	6,257,254	6,635,955	8,197,230	9,623,494	10,983,906		12,788,890	
Total Base Rate Recovery	7,501,219	7,600,498	8,072,493	9,869,182	11,338,294	13,233,906		15,409,241	
Customer Charge Recovery Percent of Total	18 642%	17.673%	17.795%	16 941%	15.124%	17 002%	17.196%	17 005%	-0 191%
Mainline Distribution Service (MLDS) 1/									
Customer Charge Revenue	50,844	93,540	104,352	68,620	65,964	76,776		76,776	
Base Rate per Dth Revenue	149,641	151,087	136,159	152,388	149,964	26,398		26,398	
Total Base Rate Recovery	200,485	244,627	240,511	221,008	215,928	103,174		103,174	
Customer Charge Recovery Percent of Total	25 361%	38 238%	43 388%	31 049%	30 549%	74 414%	40 500%	74 414%	33 914%

1/ Excludes Flexed Base Rate Revenue
2/ Residential Customer Charge included recovery of the first 2.1 Dth per month.
3/ 2011 is excluded from the average for the Residential class because the recovery of the first 2.1 Dth was included with the Customer Charge

COLUMBIA STATEMENT NO. 4

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2016-2529660
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
KELLEY K. MILLER
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

Table of Contents

I. <u>Introduction</u>

Q. Please state your name and business address.

A. Kelley K. Miller, 290 Nationwide Blvd, 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 Regulatory Analyst.

Q. What are your responsibilities as a Lead Regulatory Analyst?

A. My primary responsibilities include providing support for regulatory filings for several NiSource operating companies, including, but not limited to, Columbia Gas of Pennsylvania, Inc. ("Columbia" or "the Company"), Columbia Gas of Maryland and Columbia Gas of Massachusetts. The types of filings include rate cases and various regulatory filings. My other regular duties include account reconciliations, assisting in the planning process, providing assistance, training and oversight to other regulatory analysts and other duties as assigned.

Q. What is your educational and professional background?

A. I graduated cum laude from Ohio Wesleyan University with a Bachelor's of Arts degree in Accounting and Economics with Management Concentration in 1985. I began my professional career with the Columbia Gas System in Columbus, Ohio in 1986, beginning in the Management Information Department as an Accountant. I was promoted to Senior Accountant in 1987 in the Consolidation Accounting Department of the Columbia Gas System in Wilmington, Delaware. In 1989, I was offered and accepted a promotion to the position of Lead Accountant for Columbia Gas of Ohio as a member of Columbia Distribution Company's Financial Accounting and Reporting Architecture Team. As a member of this team, I was responsible for acting as a liaison between the Accounting departments and the project team that designed and implemented new accounting systems including the General Ledger, Employee Time Reporting and Labor Account Distribution. I remained in this role until all new systems were implemented in 1993. At that time, I was assigned the role of Lead Accountant, first for Columbia Gas of Maryland, and then Columbia Gas of Pennsylvania. Responsibilities in this role included, but were not limited to, coordinating the monthly closing process; preparing journal entries, preparing financial statements and overseeing and preparing account reconciliations. I remained in this role until 1997, when I decided to leave the workforce to start a family. During the years from 1997 to 2009 I remained out of full-time employment. In October of 2009, I accepted the position of Regulatory Analyst for NCSC. In April 2011, I was promoted to Senior Regulatory Analyst and in March of 2012, I was promoted to my current position as Lead Regulatory Analyst.

Q. Have you ever testified before a regulatory Commission?

A. Yes, I was the Cost of Service witness for Columbia Gas of Pennsylvania in Docket Nos. R-2014-2406274 and R-2015-2468056.

II. Statement of Purpose

Q. Please describe the purpose of your testimony in this proceeding.

A. The purpose of my testimony is to present Columbia's cost of service and to quantify an existing revenue deficiency based on Twelve Months Ended December 31, 2017 operating costs and revenues, as adjusted. As part of the cost of service analysis, my testimony supports all rate making adjustments to Columbia's Cost of Service Operating and Maintenance ("O&M") expenses.

Q. Would you please provide a listing of the exhibits that you are sponsoring through your testimony?

A. Yes. For the historic test year, I am supporting Exhibit 1, Exhibit 2, Exhibit 4, and Exhibit 408. For the future test year and fully forecasted rate year, I am sponsoring Exhibit 101, Exhibit 102, Exhibit 104 (in coordination with Company witness Krajovic (Columbia Statement No. 9), and Exhibit 414. All of these exhibits were either prepared by me or under my direct supervision and control.

Q. What test years will you be addressing in this testimony?

A. I will be addressing the twelve-month period ending November 30, 2015 as the "historic test year" or "HTY", the twelve-month period ending November 30, 2016 as the "future test year" or "FTY" and the twelve-month period ending December 31, 2017 as the "fully forecasted rate year" or "FFRY".

Q. What is the basis for Columbia's claim for revenue deficiency?

A. Columbia's revenue deficiency is calculated utilizing a rate year ending December 31, 2017 for rate base, revenues and expenses, with pro forma adjustments for known and measurable changes. This approach recognizes that a utility's revenues should be sufficient to recover the reasonably and prudently incurred costs of providing safe and reliable service to its customers, including a reasonable opportunity to earn a fair rate of return on the used and useful investment that the utility has devoted to such service.

Q. Would you please summarize the results of the cost of service requirement and resulting revenue deficiency?

A. As indicated on Exhibit 102, Schedule 3, Page 5, Columbia has a revenue deficiency of $55,257,002 based upon pro forma revenue requirement for the twelve months ending December 31, 2017. Columbia's computation of the revenue deficiency reflects total rate base of $1,494,091,075. In addition, the computation of the revenue deficiency reflects known and measurable changes to both utility operating income and rate base, which are explained later in my testimony and in the testimony of other Company witnesses.

Q. How is your following testimony organized?

A. I will first address the HTY, Exhibit 2 and Exhibit 4, followed by a discussion of the FTY and FFRY, Exhibit 102 and Exhibit 104.

III. HTY – Exhibit 2 – Statement of Income

Q. Please describe Exhibit 2, Schedule 3, Page 3.

A. This Exhibit is the statement of operating income, pro forma at present and proposed rates, for the HTY. Column 2 reflects the per book operating revenue, operating revenue deductions, income taxes and utility operating income for the Company for the twelve months ended November 30, 2015. These amounts have been adjusted to reflect pro forma operating income at HTY present rates in Column 4. Column 5 adjustments are detailed in Exhibit 2, Schedule 3, Page 6. Column 6 shows the resulting pro forma operating revenue, expenses and income for the HTY at proposed rates.

Q. Please describe the data inputs of Exhibit 2, Schedule 3, Page 3.

A. Operating revenues are supplied by Company witness Bell (Columbia Statement No. 3) and are included on lines 1 through 10. Witness Bell also provides the level of Gas Supply Expense and Off System Sales Expense that are included on lines 13 and 14. These two items are exactly offsetting to the level of revenue included in this case and accordingly do not impact the base rate claim in this case; rates for these items are determined in the Company's annual gas cost proceedings. I am supporting the Operating and Maintenance Expense level as presented on line 16. Lines 17 and 18, Depreciation and Amortization and Net Salvage Amortized are provided by Company witness Spanos (Columbia Statement No. 5). Taxes Other Than Income, Income Taxes and Investment Tax Credit, lines 19, 22 and 23 have been provided by Company witness Fischer (Columbia Statement No. 10), and Rate Base on line 25 has been provided by Company witness Paloney (Columbia Statement No. 6). The Percentage Rate of Return at Proposed Rates on Line 26, Column 6 is provided by Company witness Moul (Columbia Statement No. 8). Each witness' testimony provides detailed support for each of these items.

Q. Please describe Exhibit 2, Schedule 3, Pages 4 through 6.

A. Page 4 shows pro forma interest expense as calculated by multiplying the Rate Base shown in Exhibit 8 by the weighted cost of short and long term debt shown in Exhibit 400, Schedule 1, Page 1.

Exhibit 2, Schedule 3, Page 5 shows the derivation of the Revenue Conversion Factor on lines 8 through 17. The Revenue Conversion Factor is then utilized to determine the Gross Revenue Requirement.

Page 6 shows the calculated adjustments to pro forma expenses and income taxes to achieve the requested return on Rate Base of 8.15% shown on Exhibit 400 using the HTY data.

IV. HTY – Exhibit 4 - Operation & Maintenance Expenses

Q. What are Columbia's per books historic test year O&M Expenses?

A. In the HTY, Columbia recorded $166,718,012 in O&M expense exclusive of gas cost, as shown on Exhibit 4, Schedule 1, Page 2, Column 1. The O&M data is presented in a Cost Element format which provides a breakdown by cost causation.

Q. Did you make adjustments to the actual HTY O&M to reflect a pro forma HTY O&M expense level?

A. Yes. I have prepared pro forma O&M expenses for this filing. The historic test year level of O&M expense starts with O&M Expense per books, which was then normalized and annualized to determine the pro forma level of O&M Expense as summarized on Exhibit 4, Schedule 1, Page 2 and Column 5.

Q. What types of adjustments are you proposing to the O&M expense?

A. I propose the following ratemaking adjustments to the HTY, each of which will be explained in greater detail later on in my testimony:

a) The removal of Rate Case expense related to the Company's prior base rate proceeding;
b) The removal of all Polypipe related expenses and credits to expense;
c) Labor related adjustments to annualize normal payroll for employees as of the end of the HTY;
d) An adjustment to incentive compensation;
e) Removal of the negative OPEB expense;
f) Annualization of building rents and leases;
g) Corporate insurance adjusted to latest known and measurable levels;
h) Injuries and Damages adjusted to reflect a five year average of cash payments;
i) Company Memberships adjusted to latest known and measurable level;

j) Removal of fuel used in company operations;

k) Advertising adjusted to remove non-recoverable items;

l) Adjust Commission fees to latest known and measurable level;

m) NCSC costs adjusted to annualize labor and incentive costs and remove non-recoverable items;

n) Adjust deferred OPEB refund amortization to reflect the annualized level;

o) Adjust NCSC OPEB amortization level to reflect the annualized level;

p) Remove NiFiT expenses which are included in the NiFiT amortization;

q) Adjust NiFiT amortization to reflect the annualized level;

r) Removal of lobbying expenses;

s) Removal of Charitable Contributions;

t) Normalization of rate case expense;

u) Adjust Uncollectible expense;

v) Adjust USP Rider expense to match revenue; and

w) Interest on customer deposits.

A. <u>Rate Case Expense Removal</u>

Exhibit 4: *Schedule 1, Page 2, Column 2; Schedule 2, Page 1.*

Q. Please provide a brief explanation of the adjustment to remove rate case expense.

A. The HTY included actual rate case expenses related to the Company's prior 2015 base rate proceeding, Docket No. R-2015-2468056. These expenses are removed, as rate case expense is included at a normalized level in Schedule 1, Page 2, Line 27 which is explained later in my testimony. The removal of these prior rate case costs is detailed in Schedule 1, Column 2 as they impact several Cost Elements of O&M expense.

B. Removal of Polypipe

Exhibit 4: *Schedule, 1 Page 2, Column 3; Schedule 2, Page 2.*

Q. Please provide a brief explanation of the Polypipe adjustment.

A. In December 2012, the Company reached an agreement with a supplier of plastic pipe that had a manufacturing abnormality that reduced its intended service life. According to this agreement, the supplier will reimburse the Company for any costs associated with Columbia's remediation efforts. Columbia concluded its remediation efforts in August 2015. Both costs and reimbursement credits to expense should be removed from the Cost of Service for ratemaking purposes. This ratemaking practice is consistent with the removal of Polypipe related costs and reimbursement credits in Columbia's last three base rate cases. Since the HTY includes both remediation costs and credits to reimburse the Company for these costs, it is appropriate to remove both. This adjustment impacts Outside Services and is detailed in Column 3 on Exhibit 4, Schedule 1.

C. Labor

Exhibit 4: *Schedule 1, Page 2, Line 1; Schedule 2, Pages 3, 4 and 5.*

Q. Please provide a brief explanation of the labor adjustments.

A. Labor costs in the historic test year were adjusted to reflect the annualized gross base or normal wages of the 632 active Columbia employees as of November 2015. The difference, or annualization adjustment, was further adjusted to net O&M Expense by applying the labor capitalization ratio as provided on Exhibit No. 4, Schedule 2, Page 7. The resulting adjustment of $1,605,711 as calculated in Schedule 2, Page 3 is being added to the actual HTY labor expense level of $27,414,523 in Schedule 1, Page 2. Total Pro Forma HTY labor expense level is $29,020,234 as shown on Exhibit 4, Schedule 1, Page 2.

D. Incentive Compensation

Exhibit 4: *Schedule 1, Page 2, Line 2; Schedule 2, Page 6*

Q. Please provide an explanation of the HTY incentive adjustment.

A. Columbia's HTY per books incentive level of $2,017,163 was decreased by $251,009 to reflect the actual level of expense associated with incentive compensation paid in 2015. This adjustment removes any out of period true-ups for the prior year and adjusts the accrual made in the test year to the experienced pay out level at the claimed capitalization percentage. Detail supporting the historic test year adjustment is provided on Exhibit 4, Schedule 2, Page 6.

E. OPEB – Other Post Employment Benefits

Exhibit 4: *Schedule 1, Page 2, Line 4; Schedule 2, Page 8*

Q. Please describe the ratemaking adjustment for OPEB.

A. As established in the settlement of Columbia's base rate proceeding at Docket No. R-2012-2321748, Columbia will be permitted to continue to defer the difference between the annual OPEB expense calculated pursuant to FASB Accounting Standards Codification ("ASC") 715, "Compensation – Retirement Benefits (SFAS No. 106) and the annual OPEB expense allowance in rates of $0. Therefore, this adjustment removes the credit OPEB expense of $758,524 to reflect an adjusted expense level of $0, which matches the amount recovered in revenues. It is important to note that the OPEB credit amount is an accounting calculation, and the Company did not actually receive a credit payment.

F. <u>Rents and Leases</u>

Exhibit 4: *Schedule 1, Page 2, Lines 7&8; Schedule 2, Page 9*

Q. How were rents and leases adjusted for the HTY?

A. Rents and leases were first separated into a) rents and leases related to buildings, and b) other rents and leases including communications equipment and lines, office machines and furnishings. Rents and leases attributable to contractual levels for buildings were annualized on Exhibit 4, Schedule 2, Page 9 for a total of $1,390,874. This amount was then reconciled with the per book test year level of $1,408,917. The resulting adjustment was a reduction of $18,043. The remaining portion of rents and leases includes communications equipment and lines, office machines, and other items. The historic test year level related to these is $782,856 and remains unchanged.

G. <u>Corporate Insurance</u>

Exhibit 4: *Schedule 1, Page 2, Line 9; Schedule 2, Page 10*

Q. Please explain the Corporate Insurance adjustment for the historic test year.

A. Corporate insurance includes property insurance premiums, workers compensation premiums, and other miscellaneous premiums. Most premium policies are on a fiscal year ending June of each year. Most annual premium payments are generally made during July and a few are made in November. The prepayment of these costs are recorded and amortized over the appropriate fiscal period, typically July 1 through June 30. The HTY adjustment annualizes at the monthly November 2015 premium level. Detailed support for these adjustments has been provided on Exhibit 4, Schedule 2, Page 10.

H. <u>Injuries and Damages</u>

Exhibit 4: *Schedule 1, Page 2, Line 10; Schedule 2, Page 11*

Q. Was an adjustment made for injury and damages?

A. Yes. The HTY expense level for injury and damages of $394,152 represents an amount including both actual experience and adjustments to an injury and damages accrual account. A downward adjustment of $64,813 was made to represent a five (5) year average actual cash outlay experience in real dollars using a Gross Domestic Product ("GDP") Deflator. As in previous base rate cases, a 5 year average is used because it more accurately reflects the injury and damages amount actually paid. Detail supporting this adjustment is shown on Exhibit 4, Schedule 2, Page 11.

I. <u>Company Memberships</u>

Exhibit 4: *Schedule 1, Page 2, Line 12; Schedule 2, Page 12*

Q. Please explain the adjustments made for Company memberships.

A. The HTY expense for Company memberships has been adjusted for two items. The adjustment of $611 was made to remove expenses that were inadvertently recorded in the historic test year and to annualize American Gas Association dues. The details of these adjustments are shown on Exhibit 4, Schedule 2, Page 12.

J. <u>Utilities and Fuel Used in Company Operations</u>

Exhibit 4: *Schedule 1, Page 2, Line 13; Schedule 2, Page 13*

Q. What does the historic test year $426,795 adjustment for Utilities and Fuel used in Company Operations represent?

A. This $426,795 decrease to total historic test year utilities and fuel used in company operations was made to recognize inclusion of this amount as both recovery of gas cost and gas purchase expense by Company witness Bell. Columbia includes the expenses associated with gas used in company operations when establishing its gas cost recovery rates. The purchased gas is recorded as system supply and then reclassified from gas purchase to O&M expense. Therefore, it is necessary to remove the amount above from O&M for the purposes of calculating base rates and appropriately show this same level of expense in gas purchase expense along with an offsetting gas recovery level. The remaining historic test year level of $863,536 represents other utility costs, such as electric, not recovered through the 1307(f) process.

K. <u>Advertising</u>

Exhibit 4: *Schedule 1, Page 2, Line 14; Schedule 2, Page 14*

Q. Was advertising adjusted?

A. Yes. Columbia has made an adjustment to remove the expense associated with its brand advertising campaigns because this type of advertising expense is not recoverable in base rates. The Company has removed $172,528 of brand advertising from HTY costs. Please see Exhibit 4, Schedule 2, page 14 for details.

L. <u>Commission, OCA, OSBA Assessments</u>

Exhibit 4: *Schedule 1, Page 2, Line 18; Schedule 2, Page 15*

Q. Please explain the $69,941 adjustment to the HTY expense.

A. The adjustment is needed to increase the HTY expense to the most current invoice amount for Commission, Office of Consumer Advocate and Office of Small Business Advocate assessments. The normalized test year expense amount of $2,220,998 reflects the most recent invoice amount (September 10, 2015) received as of the submission of this base rate filing.

M. <u>NiSource Corporate Services Company ("NCSC")</u>

Exhibit 4: *Schedule 1, page 2, Lines 19 & 20; Schedule 2, pages 16-23*

Q. Please explain the structure and role of NCSC.

A. NCSC is a subsidiary of NiSource and an affiliate of Columbia within the NiSource corporate organization. NCSC provides a range of services to the individual operating companies within NiSource, including Columbia, and also coordinates the allocation and billing of charges to the NiSource operating companies for services provided by both NCSC directly and by third-party vendors. NCSC was established to provide centralized services economically and efficiently. The rendering of services on a centralized basis enables Columbia to realize substantial economic and other benefits including efficient use of personnel and equipment, and the availability of personnel with specialized areas of expertise.

Q. Is there a contract between Columbia and NCSC?

A. Yes. A copy of the Service Agreement is provided as Exhibit 4, Schedule 11, Attachment B. Other detailed information regarding NCSC is also provided as a part of Exhibit 4, Schedule 11.

Q. How are NCSC's costs billed to affiliates?

A. There are two types of billings made to affiliates, including Columbia: 1) contract billing; and 2) convenience billing. Contract billings are identified by billing pool and represent labor and expenses billed to the respective affiliate. Contract billed charges may be direct (billed directly to a single affiliate) or allocated (split between or among several affiliates), depending on the nature of the expense. Convenience billing reflects payments that are routinely made on behalf of affiliates on an ongoing basis, including employee benefits, corporate insurance, leasing, and external audit fees. Each affiliate is billed on a monthly basis for its proportional share of the payments made in that respective month. As the name implies, convenience billing is intended as a convenience to vendors because it eliminates the need for a separate invoice to be generated for each affiliate entity receiving the same services.

Q. How does NCSC determine charges applicable to Columbia?

A. NCSC was regulated by the Securities Exchange Commission under the Public Utility Holding Company Act of 1935 until February 8, 2006, when the Public Utility Holding Company Act of 2005 ("PUHCA 2005") was enacted. PUHCA 2005 transferred regulatory jurisdiction over public utility holding companies from the SEC to Federal Energy Regulatory Commission ("FERC"). Pursuant to FERC Order No. 684, issued October 19, 2006, centralized service companies (like NCSC) must use a cost accumulation system, provided such system supports the allocation of expenses to the services performed and readily identifies the source of the expense and the basis for the allocation. In compliance with PUHCA 2005 and FERC, NCSC accumulates costs that are applicable and billable to affiliates, including Columbia.

Q. Please describe the controls in place to ensure that an affiliate is consistently and appropriately billed.

A. NCSC allocates costs for a particular billing pool in accordance with the bases of allocation that have been previously approved by the SEC and filed annually with the FERC. A description of each of the bases of allocations are provided in the Service Agreement. NCSC currently updates the statistical data used in the approved allocation bases, at minimum, on a semi-annual basis; and furthermore, prior to publishing the new allocation percentages, NCSC provides Columbia's leadership team the opportunity to review, discuss, and provide feedback. Additionally, Internal Audit conducts an annual review of cost allocation procedures and makes recommendations related to contract and convenience billing processing.

Q. Has the FERC conducted an audit of NCSC, its billing system and allocation methodologies?

A. Yes. NiSource Inc., including NCSC, underwent a FERC audit, Docket No. FA11-5-000, which covered the period January 1, 2009, through December 31, 2010. The Final Audit Report was issued by the FERC on October 24, 2012. As indicated in the Final Report, the Audit Staff reviewed and tested the supporting details for NCSC's cost allocation methods. They then sampled and selected supporting documents to ensure that NCSC's billings and accounting comply within the USOA (Uniform

System of Accounts). FERC did not issue any adverse comments to NCSC related to its allocation methods.

Q.

Q. Please explain NCSC – Shared Services.

A. The first category, Shared Services, includes costs associated with the more traditional services that are provided by a service company, such as Accounting and Finance, Legal Services, Real Estate and Facilities, Information Technology, Human Resources, Executive, and Supply Chain.

Q. Please explain NCSC – Shared Operations.

A. The second category, Shared Operations, includes costs that are typically operational in nature or specialized, but because these groups serve all of NiSource's Operating companies, they are now a part of NCSC. These groups provide services such as Engineering, Pipeline Safety & Compliance, Technical Training, Rates and Regulatory Support, Call Center, Sales and Marketing, Gas Control, etc.

Q. Are you sponsoring the adjustments made on Exhibit 4, Schedule 1, Page 2 to NCSC – Shared Services?

A. Yes. The following adjustments have been made to NCSC - Shared Services charges for ratemaking purposes for the HTY and are summarized on Exhibit 4, Schedule 2, Page 16:

a) Adjustment to Incentive Compensation for actual incentive compensation paid in 2015;

b) Annualization of Labor, Payroll Taxes & Benefits;

c) Removal of "Phantom Stock";

d) Removal of Non-recoverable Items and Non-recurring Items.

Q. Please provide a brief overview of Exhibit 4, Schedule 2, Page 16.

A. Page 16, line 1 states the gross NCSC – Shared Services charges in the HTY. A portion of these costs are recorded to non-O&M accounts (primarily to capitalize information technology investments). Line 2 details the charges transferred to balance sheet or non-utility expenses. The HTY O&M costs generated from NCSC – Shared Services billings is $31,675,341.

Q. Please explain the various adjustments made to the actual HTY O&M costs.

A. Continuing on Exhibit No. 4, Schedule No. 2, Page 16, Lines 4 through 13 reflect adjustments made to the actual HTY O&M expense as follows:

Line 4 – Adjusts the NCSC – Shared Services Incentive Compensation to the level paid in 2015 using the latest percentage of NCSC loaded labor charges to Columbia. This calculation is detailed on Page 17.

Line 5 - Annualizes gross NCSC – Shared Services labor, payroll taxes and benefits as detailed on Page 18, net NCSC – Shared Services labor, payroll taxes and benefits adjustment is determined by applying the percentage of NCSC – Shared Services labor charged to O&M and derived on Exhibit 4 Schedule 2 Page 18 Line 14.

Lines 7 – 12 – Non-Recoverable Items that were included in the HTY are removed in the pro forma HTY expense claim.

Line 13 – Non-recurring items that were included in the HTY are removed from the pro forma HTY expense claim.

Q. Are you sponsoring the adjustments made on Exhibit 4, Schedule 1, Page 2 to NCSC – Shared Operations?

A. Yes. The following adjustments have been made to NCSC – Shared Operations charges for ratemaking purposes for the HTY and are summarized on Exhibit 4, Schedule 2, Page 20:

a) Adjustment to Incentive Compensation for actual incentive compensation paid in 2015;
b) Annualization of Labor, Payroll Taxes & Benefits;
c) Removal of Non-recoverable Items and Non-recurring Items.

Q. Please provide a brief overview of Exhibit 4, Schedule 2, Page 20.

A. Page 20, line 1 states the gross NCSC – Shared Operations charges in the HTY. A portion of these costs are recorded to non-O&M accounts (primarily capitalized in Account 107 Construction Work in Progress for support of the infrastructure investments). Line 2 details the charges transferred to balance sheet or non-utility expenses. The HTY O&M costs generated from NCSC – Shared Operations billings is $21,374,393.

Q. Please explain the various adjustments made to the actual HTY O&M costs.

A. Continuing on Exhibit No. 4, Schedule No. 2, Page 20, Lines 4 through 12 reflect adjustments made to the actual HTY O&M expense as follows:

Line 4 – Adjusts the NCSC – Shared Operations Incentive Compensation to the level paid in 2015 using the latest percentage of NCSC loaded labor charges to Columbia. This calculation is detailed on Page 21.

Line 5 - Annualizes gross NCSC – Shared Operations labor, payroll taxes and benefits as detailed on Page 22, net NCSC – Shared Operations labor, payroll taxes and benefits adjustment is determined by applying the percentage of NCSC – Shared Operations labor charged to O&M and derived on Exhibit 4 Schedule 2 Page 22 Line 15.

Lines 6 – 11 – Non-Recoverable Items that were included in the HTY are removed in the pro forma HTY expense claim.

Line 12 – Non-recurring items that were included in the HTY are removed from the pro forma HTY expense claim.

N. <u>Deferred OPEB Refund Amortization</u>

Exhibit 4: *Schedule 1. Page 2, Line 21; Schedule 2, Page 24*

Q. Has the HTY been adjusted to reflect the appropriate amount of deferred OPEB refund amortization?

A. Yes. According to the Settlement in the Company's prior base rate proceeding, Docket No. R-2015-2468056, annual amortization for Deferred OPEB Refund Amortization is $114,640. The details of this adjustment are found on Exhibit 4, Schedule 2, Page 24.

O. <u>NCSC OPEB Amortization</u>

Exhibit 4: *Schedule 1, Page 2, Line 22; Schedule 2, Page 25*

Q. Has the HTY been adjusted to reflect the appropriate amount of NCSC OPEB amortization?

A. Yes. According to the Settlement in the Company's 2012 base rate proceeding, Docket No. R-2012-2321748, the Company is permitted to amortize the regulatory asset of $903,131 associated with the transition of NCSC from a cash to accrual basis for OPEBs, over a ten year period, or $90,313 annually. Exhibit 4, Schedule 2, Page 25 shows that no adjustment is required as the HTY correctly reflects the annualized level of amortization expense of $90,313.

P. <u>NiFiT Expense</u>

Exhibit 4: *Schedule 1, Page 2, Line 23; Schedule 2, Page 26*

Q. Please explain the adjustment to NiFiT Expense.

A. Per the Settlement approved at Docket No. R-2012-2321748, Columbia was allowed amortization recovery of the estimated non-labor NiFiT expenses over a four-year period. Upon approval of the settlement by the Commission, Columbia removed all non-labor NiFiT expenses to date by deferring the expenses to a regulatory asset. In January 2014, Columbia reached the maximum amount of the allowed deferral according to the Settlement; additional non-labor NiFIT costs were expensed. Per the Settlement approved in Docket No. R-2014-2406274, the total amount of estimated non-labor expenses that could be deferred and amortized was adjusted to reflect additional eligible costs incurred beginning in January 2014. The entry that was required to remove the additional non-labor NiFit expenses of $530,495 and defer the expenses to the regulatory asset was made in December 2014, which falls within the HTY. Exhibit 4, Schedule 2, Page 26 identifies the amount of non-labor NiFiT expense (a credit) that needs to be removed from the HTY.

Q. <u>NiFiT Amortization</u>

Exhibit 4: *Schedule 1, Page 2, Line 24; Schedule 2, Page 27*

Q. Please explain the NiFiT Amortization adjustment.

A. According to the Settlement in the Company's prior base rate proceeding, Docket No. R-2015-2468056, the Company is permitted to defer and amortize over a three year period, non-labor start-up costs of the new financial software of $1,260,764, which was the remaining level of non-labor expense. NiFiT Amortization has been adjusted to this new level of $420,255. Please see Exhibit 4, Schedule 2, Page 27 for the details of this adjustment.

R. <u>Lobbying Expense</u>

Exhibit 4: *Schedule 1, Page 2, Line 25; Schedule 2, Page 28*

Q. Please describe the lobbying expense adjustment.

A. An adjustment has been made for the removal of lobbying expenses related to labor as well as other O&M cost drivers. As such, this adjustment has not been categorized by cost driver but instead is shown as a stand-alone line item on Exhibit 4, Schedule 1, Page 2, Line 25. Detail for this adjustment is provided on Exhibit 4, Schedule 2, Page 28.

S. <u>Charitable Contributions</u>

Exhibit 4: *Schedule 1, Page 2, Line 26; Schedule 2, Page 29*

Q. How were charitable contributions treated as a cost of service item?

A. Charitable contributions are normally booked below the line in a non-utility account and are not a part of Columbia's claim as a cost of service item. Please see Exhibit 4, Schedule 2, page 29 for the details of removing any contributions that were inadvertently booked above the line.

T. <u>Rate Case Expense Normalization</u>

Exhibit 4: *Schedule 1, Page 2, Line 27; Schedule 2, Page 30*

Q. Has the Company included a normalized level of rate case expense in its HTY Cost of Service?

A. Yes. The approved rates from the Company's last rate case include an amount for recovery of rate case expenses. As explained previously, actual rate case expense from the Company's prior rate case has been removed from pro forma HTY expense. I have included a normalized level of rate case expense based on the proposed rate case expense normalization included in this current case as determined on Exhibit 4, Schedule 2, and Page 30. The Company is using a one year normalization period due to annual base rate cases.

U. <u>Uncollectible Accounts Expense</u>

Q. Please explain Columbia's claim for recovery of uncollectible accounts expense.

A. Two major categories of uncollectible accounts have been recorded historically and have been represented in the development of cost of service support. These two categories are "normal" (or non-CAP) uncollectible accounts and Customer Assistance Program ("CAP") uncollectible accounts.

Normal uncollectible accounts expense has been developed on Exhibit 4, Schedule 2, Page 31 for the HTY. The CAP uncollectible accounts expense related to the CAP shortfall has been developed and is included in Total USP Rider on Exhibit 4, Schedule 2, Page 34 for the HTY.

V. Normal Uncollectible Accounts

(Uncollectible Accounts & Uncollectible Accounts – Unbundled gas)

Exhibit 4: *Schedule 1, Page 2, Line 28 & 29; Schedule 2, Pages 31 – 33*

Q. Please explain the development of the HTY normal uncollectible accounts expense.

A. Exhibit 4, Schedule 2, pages 31 through 33 set forth the development of a percentage for uncollectible accounts related to normal charge offs recovered through base rates.

The write off percentage for charge offs related to normal customers recovered through base rates is calculated based on comparing the three-year average of write-offs for normal uncollectible accounts expense to billed revenue. Several adjustments to billed revenue are necessary to develop the write off percentage. First, account write-offs lag billed revenue by approximately 120 days or 4 months. This lag in days includes consideration for the time between original billing and an account being placed into final status, as well as consideration for the average time between an account being placed into final status and termination of service, which is when the account is written-off. I have used billed revenue for the twelve months ended July of each year to appropriately reflect the lag (4 months) between the billing and write-off of accounts.

Additionally, I have provided on Page 32 the average write-off rate for Residential customers as well as the combined write-off rate for Commercial and Industrial customers. This information was utilized by Company witness Bell in the development of the Merchant Function Charge.

Q. What other adjustments have been made to billed revenue?

A. Columbia's Distributive Information System ("DIS") billing system is used to bill all residential and small business accounts and, therefore, includes revenues applicable to CAP customer accounts. Exhibit 4, Schedule 2, Line 2 of Page 31, titled as, "Total DIS Billed Revenue," has been adjusted to remove the revenue associated with Columbia's CAP (Page 31, Line 3), as CAP uncollectibles are accounted for separately. Exhibit 4, Schedule 2, Line 4 of Page 31 represents Adjusted DIS Billed Revenue that relates to the net write-offs as shown on Exhibit 4, Schedule 2, Line 9 of Page 31.

Q. How were the net write-offs shown on Line 9 developed?

A. The net write-offs shown on Exhibit 4, Schedule 2, Line 9 of Page 31 represent the summation of gross charge-offs and recoveries for all customers billed through DIS.

Q. How are the adjusted billed revenue and net write-off amounts used in the development of normal uncollectibles?

A. The three years of adjusted revenue is added together to generate the total revenue as shown on Line 4. Similarly, a three year total is developed for net write-offs. An uncollectible rate is then calculated by dividing the total net write-off by the total adjusted revenue. This rate, which is shown on line 10, is then applied to the annualized DIS revenue as provided by witness Bell for the historic test year. The result is Columbia's adjusted historic test year normal uncollectibles for DIS billed customers, line 16.

Q. Does this fully describe all adjustments made to the historic test year normal uncollectible expense?

A. No. DIS is one of three billing systems used to bill revenue related to normal uncollectible write-offs. The other billing systems, the Gas Transportation System ("GTS") and Gas Measurement Billing ("GMB"), are used to bill larger customers including chart read customers, daily read customers, customers with multiple rate components, and non-CHOICE transportation customers. A three year average net write-off was developed for uncollectible accounts related to these larger customers. Columbia did not include these write-off amounts in the calculation of a net write-off rate, as was done for DIS billed accounts, because larger customer write-offs occur infrequently, but can produce disproportionate write-off amounts when they do occur, as can be seen in the three-year experience write offs for this type of customer.

Q. Please summarize Columbia's proposed normal historic test year uncollectible accounts expense adjustments.

A. The historic normal uncollectible adjustment is a decrease to expense of $330,195 as shown on Exhibit 4, Schedule 1, Page 2, Lines 28 and 29. This amount has been developed by comparing an annualized DIS, GTS, and GMB net write-off as described above and comparing that to the normal uncollectible expense level as recorded in Columbia's test year ending November 30, 2015.

W. Rider USP Costs

(Uncollectible CAP – Rider USP & Rider USP – LIURP/Energy Efficiency)

Exhibit 4: *Schedule 1, Page 2, Line 30; Schedule 2, Page 34*

Q. Are you sponsoring an adjustment for Rider USP costs as well?

A. Yes. A Rider USP adjustment has been made to the HTY as shown on Exhibit 4, Schedule 2, Page 34.

Q. Please explain the test year adjustment.

A. The adjustment is a result of the matching of expenses to revenue, as Rider USP is a fully reconciled mechanism. As calculated in Exhibit 3, Page 10, Rider USP revenues are $21,596,644 for the normalized HTY. Consequently, the adjustment reflects changes that are necessary to match the expense with the revenues as determined by Company witness Bell. As a result, the Rider USP net impact to operating income is zero with the expense offsetting revenues. Therefore, Rider USP costs do not impact the base rate increase requested in this case.

X. Interest on Customer Deposits

Exhibit 4: *Schedule 1, Page 2, Line 31; Schedule 2, Page 35*

Q. Please explain the adjustment for Interest on Customer Deposits.

A. An adjustment for interest on customer deposits is necessary to recognize the expense related to interest recorded on customer deposits not included in O&M Expense on the books and records of Columbia. Customer deposits are considered a source of capital in Columbia's rate base for this case and, as such, reduce rate base. This adjustment is made to recognize the expense related to this source of capital. The adjustment reflects the 3% interest rate on customer deposits established under Chapter 14 of the Public Utility Code applied to the average customer deposit balance. No further adjustment is made to this item for either the future test year or the fully forecasted rate year, because the Company has made no projection of changes to the balance of customer deposits.

V. <u>FTY/FFRY – Exhibit 102 – Statement of Income</u>

Q. Is Exhibit 102 presented in the same format as Exhibit 2?

A. Yes. Exhibit 102, Schedule 3 is a Statement of Income based on FTY, FFRY and Proposed Rates. Exhibit 102, Schedule 3, Page 3 as referenced earlier in my testimony when describing Exhibit 2, Schedule 3, Page 3, utilizes data that has been provided by other witnesses in this case to determine a revenue requirement. This Exhibit begins with the FTY at present rates in Column 2 and the FFRY in Column 4. Adjustments in Column 5 are then made to determine the FFRY at proposed rates in Column 6. Column 5 shows the revenue requirement of $55,257,002 necessary to achieve a reasonable opportunity to earn a fair rate of return. The various exhibits in support of the adjustments at present and proposed rates are identified in Columns 1 and 3.

Q. Please explain Exhibit 102, Schedule 3, Page 4.

A. This page calculates synchronized interest expense based upon the FTY rate base multiplied by the weighted cost of debt in Lines 1 through 4 and similarly based on the FFRY year rate base multiplied by the weighted cost of debt in Lines 5 through 8.

Q. Please explain Page 5 of Exhibit 102, Schedule 3.

A. This page presents the calculation of the required revenue increase of $55,257,002 using the revenue conversion factor. The revenue conversion factor accounts for additional normal uncollectible expense of $705,946 generated by Columbia's requested increase in revenues as calculated on page 6 of Exhibit 102 as well as additional Late Payments Fees of $134,169, which is calculated by first determining an experience rate of Late Payments Fees at present rates. This is done by dividing the amount of total Late Payment Fees on Exhibit 102, Schedule 3, Page 3, Column 4, Line 10 by Total Sales and Transportation Revenues on Exhibit 102, Schedule 3, Page 3, Column 4, Line 8. This experience factor is then applied to the Additional Revenue Requirement on Line 1 of Exhibit 102, Schedule 3, Page 6 to determine the additional Late Payment Fees.

The effective State Income Tax rate has been recalculated and reflects differences in the tax net operating loss positions.

VI. FTY/FFRY – Exhibit 104 – Operations and Maintenance Expense

Q. Did you utilize a budget-based methodology to determine O&M Expense for the FTY and the FFRY as Columbia has done in the prior base rate proceeding?

A. Yes. FTY and FFRY levels of O&M expense begin with the budget as supplied and supported by Company witness Krajovic (Columbia Statement No. 9). A month by month presentation can be found on Exhibit 104, Schedule 1, Pages 5 and 6. Ratemaking adjustments have been made to normalize and annualize the budget to arrive at Pro Forma O&M Expenses.

Q. Please describe Exhibit 104, Schedule 1.

A. Exhibit 104, Schedule 1 contains a total of six pages and provides a clear distinction between "Budget Adjustments" and "Ratemaking Adjustments" for both the FTY and the FFRY. Company witness Krajovic is supporting all budget adjustments, while I am supporting all ratemaking adjustments.

Q. Please provide a brief description of each of the 6 pages of Exhibit 104, Schedule 1.

A. Page 1 references pages 2 – 6 of the Exhibit.

Page 2 is the summary view of O&M Expense for all test years in this case. Column 1 presents the Normalized HTY, Column 3 presents the Normalized FTY and Column 5 presents the Normalized FFRY. Columns 2 and 4 provide both the budget adjustments and the rate making adjustments that adjust the HTY to the FTY and the FTY to the FFRY.

Pages 3 and 4 are formatted in a similar manner. Page 3 contains details for the FTY; while page 4 contains the details for the FFRY. Page 3 starts with the Normalized HTY in column 1, followed by the Budget Adjustments & References (Columns 2 and 3) that adjust from the Normalized HTY to the Budgeted FTY (Column 4) which is supported by Company witness Krajovic. Columns 5 and 6 provide Rate Making Adjustments and References followed by the Normalized FTY (Column 7). Similarly, Page 4 provides the details for the FFRY, starting with the Normalized FTY (Column 1; from page 3) followed by the Budget Adjustments & References (Columns 2 and 3) that adjust from the Normalized FTY to the Budgeted FFRY (Column 4) which is also supported by Company witness Krajovic. Columns 5 and 6 provide Rate Making Adjustments and References followed by the Normalized FFRY (Column 7).

Pages 5 and 6 provide the monthly Budget Data for FTY (Page 5) and FFRY (Page 6); supported by witness Krajovic.

Q. Did you utilize the O&M budget for all the O&M items on Exhibit No. 104?

A. No. Lines 1 through 24 on Exhibit No. 104, Schedule No. 1, Column 4, Pages 3 and 4 reflect the O&M budget data used in the FTY and FFRY periods. The O&M budget data was not utilized for the cost items noted on Lines 26 through 31 of these same pages. These items include:

- Line 26 – Rate Case Expense – the amounts reflect normalized costs associated with the current case that should be included in the revenue requirement in this case.
- Lines 27– Uncollectible Accounts – the uncollectible expense is reflective of the standard practice of using a 3 year average of charge-off experience of FTY and FFRY revenues as provided by Company witness Bell.
- Lines 28 & 29 – Uncollectible Accounts – Unbundled – Gas & Total Rider USP – the amounts are adjusted to reflect the amounts included in revenues as provided by Company witness Bell.
- Line 30 – Interest on Customer Deposits – this item is not included in the O&M budget.
- Line 31 – Other Adjustments – these items were not identified in time to be included in the O&M budget that was used as the starting point for the FFRY period.

Q. What types of adjustments are you proposing to O&M expense for the FTY and FFRY?

A. I propose the following ratemaking adjustments to determine Pro Forma O&M Expense for the FTY and FFRY, which I will explain in detail later on in my testimony:

a) Annualization of Company Labor;

b) Adjust Pension expense to reflect a two year average of cash contributions;

c) Removal of the negative OPEB expense;

d) Annualization of building rents and leases;

e) Injuries and Damages adjusted to reflect HTY plus inflation;

f) Removal of fuel used in company operations;

g) Advertising adjusted to a normalized level of recoverable expense;

h) NCSC costs adjusted to annualize labor and remove non-recoverable items;

i) Adjust deferred OPEB refund amortization to reflect the annualized level;

j) Adjust NiFiT amortization to reflect the annualized level;

k) Removal of lobbying expenses;

l) Normalization of rate case expense;

m) Adjust Uncollectible expense;

n) Adjust Rider USP expense to match revenue;

o) Other Adjustments to the FFRY.

A. <u>Labor</u>

Exhibit 104: *Schedule 1, Page 2, Line 1; Schedule 2, Page 1*

Q. Please provide a brief explanation of the labor adjustments.

A. Columbia has determined annualization adjustments for the FTY of $379,769 and for the FFRY of $336,714. These adjustments are for normal pay increases only, for labor charges prior to the timing of the annual budgeted increases, and reflect an O&M percentage of 58.10% which is the same percentage as used in the Budget for items that have been adjusted from gross amounts to net O&M expense.

B. <u>Pension Expense</u>

Exhibit 104: *Schedule 1, Page 2, Line 3; Schedule 2, Page 2*

Q. What is the basis for the Company's qualified Pension claim?

A. The Company's claim for the qualified pension expense is based on Pension Contributions made by the Company to the Pension trust. Specifically, the gross claim is based on a two year average of the gross Pension contributions. These gross amounts are then adjusted to expense based on the O&M percentage rate.

Q. Please explain the calculation of the future test year qualified pension adjustment.

A. Columbia's FTY expense was adjusted to reflect the average annual contributions using a 2-year average ending November 30, 2016 – Exhibit No. 104, Schedule No. 2, Page 2, Line 5. Further, Line 7 calculates the net portion charged to O&M. An adjustment is determined when compared to the amount included in the budget, Line 8. Included in the 2-year average are projected pension contributions as provided by AON Hewitt and provided on Exhibit 104, Schedule 2, Page 3.

Q. Please explain the calculation of the FFRY qualified pension adjustment.

A. Columbia's fully forecasted rate year expense was adjusted to reflect the average annual contributions using a 2 year average ending December 31, 2017 – Exhibit No. 104, Schedule No. 2, Page 2, Line 14. Further, Line 16 calculates the net portion charged to O&M. An adjustment is determined when compared to the amount included in the budget, Line 17. Included in the 2 year average are projected pension contributions as provided by AON Hewitt and provided on Exhibit 104, Schedule 2, Page 3.

C. OPEB – Other Post Employment Benefits

Exhibit 104: *Schedule 1, Page 2, Line 4; Schedule 2, Page 4*

Q. Please explain the ratemaking for OPEB Expense as approved in the Company's last rate case.

A. Provision Nos. 53 and 54 of the settlement agreement of the Company's last base rate case address this subject by stating:

> 53. As established in the settlement of Columbia's base rate proceeding at R-2012-2321748, Columbia will be permitted to continue to defer the difference between the annual OPEB expense calculated pursuant to FASB Accounting Standards Codification ("ASC") 715, Compensation – Retirement Benefits (SFAS No. 106) and the annual OPEB expense allowance in rates of $0. Only those amounts attributable to operation and maintenance would be deferred and recognized as a regulatory asset or liability. To the extent the cumulative balance recorded reflects a regulatory asset, such amount will be collected from customers in the next rate proceeding over a period to be determined in that rate proceeding. To the extent the cumulative balance recorded reflects a regulatory liability, there will be no amortization of the (non-cash) negative expense, and the cumulative balance will continue to be maintained.
>
> 54. Commencing with the effective date of rates, Columbia will deposit amounts in the OPEB trusts when the

> cumulative gross annual accruals calculated by its actuary pursuant to ASC 715 are greater than $0. If annual amounts deposited into OPEB trusts, pursuant to this Settlement, exceed allowable income tax deduction limits, any income taxes paid will be recorded as negative deferred income taxes, to be added to rate base in future proceedings.

Q. Is the Company proposing a change to these provisions?

A. No. The cumulative OPEB expense at the end of the HTY is less than zero and the expected on-going OPEB expense continues to reflect credit expense. Therefore, the Company proposes to continue using this ratemaking treatment for OPEB expense.

Q. Do the ratemaking adjustments for OPEB Expense as presented on Exhibit 104, Schedule 2, Page 4 comply with the provisions as listed above?

A. Yes, the FTY and FFRY adjustments remove from the budgets the credit OPEB expense of $860,000 and $859,000, respectively to reflect an adjusted expense level of $0. I emphasize that these credit amounts are not projected cash receipts, but just accounting credits.

D. Rents and Leases

Exhibit 104: *Schedule 1, Page 2, Line 7; Schedule 2, Page 5*

Q. Please explain the adjustment to rents and leases for the FTY and FFRY.

A. Known changes to building leases were included on Exhibit 104, Schedule 2, Page 5 resulting in an increase of $494,803 for the FTY claim and an increase of $9,248 for the FFRY claim. Please see Company witness Krajovic's testimony for more detail regarding rents and leases.

E. <u>Injuries and Damages</u>

Exhibit 104: *Schedule 1, Page 2, Line 9; Schedule 2, Page 6*

Q. Was an adjustment made for injuries and damages?

A. Yes. The FTY and FFRY expense levels for injury and damages were adjusted to reflect the pro forma HTY claim of $329,339 plus applicable inflationary adjustments. As stated earlier in my testimony, the pro forma HTY claim reflects the average claim payments for the five years ending November, 30, 2015.

F. <u>Utilities and Gas Used in Company Operations</u>

Exhibit 104: *Schedule 1, Page 2, Line 12; Schedule 2, Page 7*

Q. Please explain the adjustment for Gas Used in Company Operations.

A. The FTY and FFRY O&M budget amounts include costs associated with Gas Used in Company Operations. In a manner similar to what was done in the HTY pro forma adjustments, an adjustment is also needed to eliminate these costs in the FTY and FFRY periods. The adjustments were calculated using the HTY adjustment level plus an inflationary adjustment.

G. Advertising

Exhibit 104: *Schedule 1, Page 2, Line 13; Schedule 2, Page 8*

Q. Please explain the adjustment for Advertising.

A. The FTY and FFRY O&M budget amounts are not prepared at a level that identify the specific types of advertising. The HTY advertising included a portion of non-recoverable advertising, so for the future periods I have made adjustments to include a representative level of recoverable advertising. In a manner similar to the adjustment for Injuries and Damages, the pro forma level of HTY Recoverable Advertising was adjusted for inflation and included as the Advertising claim for the FTY and FFRY periods. This includes making significant reductions to the levels of advertising expense in the Budget for both periods.

H. NiSource Corporate Services Company "NCSC"

Exhibit 104: *Schedule 1, Page 2, Lines 18 & 19; Schedule 2, Pages 9 - 14*

Q. Are you sponsoring any ratemaking adjustments to NCSC for the FTY and FFRY?

A. Yes. In a manner similar to the HTY, NCSC Budget and Ratemaking has been broken out into two categories of Expense: NCSC – Shared Services and NCSC – Shared Operations. Exhibit 104, Schedule 2, Page 9 summarizes the ratemaking adjustments to NCSC – Shared Services for the FTY and FFRY; ratemaking adjustments for NCSC – Shared Operations are summarized on page 12.

I have made adjustments to annualize labor and to remove non-recoverable items for both future periods. Pages 10 and 13 provide adjustments to annualize labor; the annualization is similar to the adjustments that I am proposing on Exhibit 104, Schedule 2, Page 1 for Company labor. The FTY adjustment represents 3% of budgeted labor charges from December 2015 through May 2016, which annualizes labor for the months prior to the budgeted annual 3% increase to labor which occurs on June 1. In a similar fashion, the FFRY has been adjusted to include 3% of budgeted labor charges for January 2016 through May 2017.

Pages 11 and 14 determine the adjustments for the removal of non-recoverable items. These adjustments are based upon the HTY level of expense, plus incremental adjustments that are produced by using inflation factors.

I. OPEB Deferral Passback Amortization Adjustment

Exhibit 104: *Schedule 1, Page 2, Line 20; Schedule 2, Page 15*

Q. Please explain the level of OPEB Deferral Passback Amortization in the FTY claim.

A. The FTY amortization has been adjusted to reflect the actual amortization as stated in the settlement agreement in the last base rate case, Docket No. R-2015-2468056.

Q. Please explain the level of OPEB Deferred Passback Amortization in the FFRY claim.

A. The estimated OPEB deferral balance at January 1, 2017 (the commencement of the FFRY period) is anticipated to be $0, therefore the budgeted amount of $229,000 was removed. The estimated January 1, 2017 balance of $0 is calculated on Line 12 of Exhibit 104, Schedule 2, Page 15.

J. <u>NiFiT Non-Labor Amortization Adjustment</u>

Exhibit 104: *Schedule 1, Page 2, Line 23; Schedule 2, Page 16*

Q. What is the adjustment to the FTY for NiFiT Non-Labor Amortization?

A. The FTY expense has been adjusted to reflect the actual amortization for this item as it was stated in the last rate case order: $1,260,764 over a three year period or $420,252.

Q. Does the Company propose to revise the amortization for the FFRY period?

A. No, the FFRY level of amortization has also been adjusted to the approved annual amortization of $420,252.

K. <u>Lobbying Expense</u>

Exhibit 104: *Schedule 1, Page 2, Line 24; Schedule 2, Page 17*

Q. Please describe the lobbying expense adjustment.

A. An adjustment has been made for the removal of lobbying expenses. The FTY and FFRY adjustments are based upon the HTY level of expense adjusted for inflation.

L. <u>Normalization – Rate Case Expenses</u>

Exhibit 104: *Schedule 1, Page 2, Line 26; Schedule 2, Page 18*

Q. Has Columbia included an adjustment for rate case expense?

A. Yes. Exhibit 104, Schedule 2, Page 18 sets forth the Company's claim for rate case expenses. The estimated expenses for this rate case reflects costs to be incurred for Columbia's cost of capital witness, depreciation witness, outside counsel, and incremental costs associated with legal notices, employee expenses and duplicating. The entire rate case expense included for normalization is $1,030,000. Columbia proposes to normalize these costs over 12 months.

M. <u>Normal Uncollectible Accounts Expense</u>

(Uncollectible Accounts & Uncollectible Accounts – Unbundled gas)

Exhibit 104: *Schedule 1, Page 2, Line 27 & 28; Schedule 2, Page 19*

Q. Please explain the FTY and FFRY claim for normal uncollectible accounts expense.

A. I have utilized the Uncollectible Accounts Average Write-off Rate as developed on Exhibit 4, Schedule 2, Page 31 which represents a three year average experience of net write-offs as a percentage of billed DIS revenues. This rate is applied to annualized FTY/FFRY DIS revenues after adjusting for CAP revenue, to arrive at Total DIS Uncollectible Accounts Expense for the FTY and FFRY.

Q. Has Columbia reflected the unbundling of uncollectibles related to gas costs?

A. Yes. Columbia has identified a portion of the normal uncollectibles that will be collected through the Merchant Function Charge.

Q. What amount is attributed to the uncollectibles related to gas costs?

A. Columbia has identified $1,103,635 in the FFRY expenses associated with the unbundling of uncollectibles related to gas costs. This amount is included in the O&M expense claim and is offset by the same amount of revenues in Exhibit 103 as developed by Company witness Bell. As a result, the net impact to operating income is zero and does not impact the base rate increase requested in this case. Please refer to Exhibit 104, Schedule 2, Page 19 for details.

N. <u>Total Rider USP Costs</u>

Exhibit 104: *Schedule 1, Page 2, Line 29; Schedule 2, Page 20*

Q. Please explain the test year adjustments.

A. The adjustments reflected in Exhibit 104 are a result of the matching of expenses to revenue, as Rider USP is a fully reconciled mechanism. As calculated in Exhibit 103, Rider USP revenues at present rates are $21,610,640 for the FTY and $21,659,275 for the FFRY. As a result, the Rider USP net impact to operating income is zero with the expense offsetting present rate revenues. Therefore, Rider USP costs do not impact the base rate increase requested in this case. Ms. Bell computes the increase to Rider USP resulting from the proposed rate increase.

O. <u>Other Adjustments to the FFRY</u>

Exhibit 104: *Schedule 1, Page 2, Line 31; Schedule 2, Page 21*

Q. Are there any other adjustments to O&M Expense that impact Columbia's claim in this case?

A. Yes, Exhibit 104, Schedule 2, Page 21 summarizes the following two additional adjustments totaling $874,357:

- Proposed Multifamily House Line Reimbursement; and
- Transaction Fees Proposal.

These adjustments are being sponsored by Company witness Waruszewski (Columbia Statement No. 13), and details about these adjustments can be found in his testimony.

Q. Does this complete your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 5

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
vs.	)	Docket No. R-2016-2529660
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
JOHN J. SPANOS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

MARCH 18, 2016

Q. Please state your name and address.

A. John J. Spanos. My business address is 207 Senate Avenue, Camp Hill, Pennsylvania.

Q. With what firm are you associated and in what capacity?

A. I am associated with the firm of Gannett Fleming Valuation and Rate Consultants, LLC (Gannett Fleming) as Senior Vice President.

Q. How long have you been associated with Gannett Fleming?

A. I have been associated with the firm since college graduation in June 1986.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College of Pennsylvania.

Q. Are you a member of any professional societies?

A. Yes. I am a member and past President of the Society of Depreciation Professionals. I am also a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Have you taken the certification examination for depreciation professionals?

A. Yes, I passed the certification examination of the Society of Depreciation Professionals in September 1997 and was recertified in August 2003, February 2008 and January 2013.

Q. Will you outline your experience in the field of depreciation?

A. I have 30 years of depreciation experience which includes expert testimony in over 200 cases before approximately 40 regulatory commissions, including the Pennsylvania Public Utility Commission (the "Commission"). Please refer to Appendix A for my qualifications.

Q. What is the purpose of your testimony?

A. My testimony is in support of the depreciation studies conducted under my direction and supervision for the gas plant of Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company").

Q. Have you prepared exhibits presenting the results of your studies?

A. Yes. Exhibit No. 9 presents the results of the depreciation study as of November 30, 2015. Exhibit No. 109, Schedule No. 1, Attachment A presents the results of the depreciation study as of November 30, 2016. Exhibit No. 109, Schedule No. 1, Attachment B presents the results of the depreciation study as of December 31, 2017. In addition, I am responsible for the responses to the following filing requirements pertaining to depreciation under Section 53.53(a)(1) of the Commission's regulations: 3, 4, 5, 6, 7 and 17. I also sponsor Exhibit No. 5 and Exhibit No. 105, which are summaries of the results to Exhibit No. 9 and Exhibit No. 109, respectively.

Q. Please describe Exhibit Nos. 9 and 109.

A. Exhibit No. 9, Schedule No. 1, titled "2015 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2015," includes the results of the depreciation study as related to the original cost at November 30, 2015. The report also includes the detailed depreciation calculations. Exhibit No. 109, Schedule No. 1, Attachment A, titled "2016 Depreciation Study - Calculated Annual Depreciation Accruals Related to Gas Plant as of November 30, 2016," includes the results of the depreciation study as related to the estimated original cost at November 30, 2016. The report also includes explanatory text, statistics related to the estimation of service life, and the detailed depreciation calculations. Exhibit No. 109, Schedule No. 1, Attachment B, titled "2017 Depreciation Study – Calculated Annual Depreciation Accruals Related to Gas Plant as of December 31, 2017," includes the results of the depreciation study as related to the estimated original cost at December 31, 2017.

Q. What were the purposes of your depreciation studies?

A. The purposes of the depreciation studies were to estimate the annual depreciation accruals related to gas plant in service for ratemaking purposes and, using Commission-approved procedures, to estimate the Company's book reserve at November 30, 2016, and December 31, 2017.

Q. Is the Company's claim for annual depreciation in the current proceeding based on the same methods of depreciation as were used in its most recent Annual Depreciation Report filed in June 2015 and service life study filed in August 2012?

A. Yes, it is. For most plant accounts, the current claim for annual depreciation is based on the straight line remaining life method of depreciation, which has been used for over twenty years. For Accounts 391.1, 391.11, 391.12, 392, 393, 394, 395, 397.1 and 398, the claim is based on the straight line remaining life method of amortization. The accounts have a large number of units, but small asset values representing less than 2 percent of the depreciable plant. The assets represent items located in office buildings, service centers, garages and warehouses. Given the difficulty in maintaining accounting records for these numerous assets and high cost for periodic inventories, retirements are recorded when a vintage is fully amortized, rather than as the units are removed from service. All units are retired when the age of the vintage reaches the amortization period. The annual amortization is based on amortization accounting which distributes the unrecovered cost of fixed capital assets over the remaining amortization period selected for each account.

Q. What group procedure is being used in this proceeding for depreciable accounts?

A. The average service life procedure is used in the current proceeding for plant installed prior to 1976 and the equal life group procedure for 1976 and subsequent vintages. This calculation has been used in the same manner as the Company's most recent annual depreciation reports.

Q. Is the Company's claim for accrued depreciation in the current proceeding made on the same basis as has been used for over twenty years?

A. Yes. The current claim for accrued depreciation is the book reserve brought forward from the book reserve approved by the Commission in the last proceeding.

Q. How was the book reserve used in the calculation of annual depreciation?

A. The book reserve by account was allocated to vintages to determine original cost less accrued depreciation by vintage. The total annual accrual is the sum of the results of dividing the original costs less accrued depreciation by the vintage composite remaining lives.

Q. How was the book reserve at November 30, 2016, estimated?

A. The book reserve at November 30, 2016, by account, was projected by adding estimated accruals, salvage and the amortization of net salvage, and subtracting estimated retirements and cost of removal from the book reserve at November 30, 2015. Annual accruals were estimated using the annual accruals calculated as of November 30, 2015. For most accounts, salvage and cost of removal were estimated by (1) expressing actual salvage and cost of removal as a percent of retirements by account, for the most recent five-year period, and (2) applying those percents to the projected retirements by account. For the purpose of calculating the annual accruals, the projected book reserve by account was allocated to vintages based on calculated accrued depreciation at November 30, 2016.

Q. Was the book reserve at December 31, 2017, estimated using the same methodology?

A. Yes.

Q. Has a service life study of the Company's gas utility property been performed?

A. Yes. The most recent service life study was performed as of December 2011. The service life study is the basis for the service lives I used to calculate annual accruals.

Q. Briefly outline the procedure used in performing the service life study.

A. The service life study consisted of assembling and compiling historical data from the records related to the gas utility plant of the Company; statistically analyzing such data to obtain historical trends of survivor characteristics; obtaining supplementary information from management and operating personnel concerning Company practices and plans as they relate to plant operations; and interpreting the above data to form judgments of service life characteristics.

Iowa type survivor curves were used to describe the estimated survivor characteristics of the mass property groups. Individual service lives were used for major individual units of plant, such as distribution buildings housing offices and shops. The life span concept was recognized by coordinating the lives of associated plant installed in subsequent years with the probable retirement date defined by the life estimated for the major unit.

Q. What statistical data were employed in the historical analyses performed for the purpose of estimating service life characteristics?

A. The data consisted of the entries made to record retirements and other transactions related to the gas plant during the period 1939-2011. The year 1939 is the first year continuing property records were maintained. These entries were classified by depreciable group, type of transaction, the year in which the transaction took place, and the year in which the plant was installed. Types of transactions included in the data were plant additions, retirements, transfers, and balances. In the presentation of service life statistics, only the significant exposure points that were utilized in determining survivor curves were plotted. This process is utilized to show my judgment in service life determinations.

Q. What was the source of these data?

A. They were assembled from Company records related to its gas plant in service.

Q. Were the methods used in the service life study the same as those used in other depreciation studies for gas utility plant presented before this Commission?

A. Yes. The methods are the same ones that have been presented previously for Columbia and for other gas companies before the Commission and that have been accepted by the Commission in its past orders concerning gas utilities.

Q. What approach did you use to estimate the lives of significant structures such as office buildings and service centers?

A. I used the life span technique to estimate the lives of significant structures. In this technique, the survivor characteristics of the structures are described by the use of interim survivor curves and estimated probable retirement dates. The interim survivor curve describes the rate of retirement related to the replacement of elements of the structure such as plumbing, heating, doors, windows, roofs, etc. that occur during the life of the facility. The probable retirement date provides the rate of final retirement for each year of installation for the structure by truncating the interim survivor curve for each installation year at its attained age at the date of probable retirement. The use of interim survivor curves truncated at the date of probable retirement provides a consistent method for estimating the lives of the several years of installation inasmuch as concurrent retirement of all years of installation will occur when the structure is retired.

Q. Has your firm used this approach in other proceedings before this Commission?

A. Yes, we have used the life span technique on many occasions before the Commission.

Q. What are the bases for the probable retirement years that you have estimated for each structure?

A. The bases for the estimates of probable retirement years are life spans for each structure that are based on judgment and incorporate consideration of the age, use, size, nature of construction, management outlook and typical life spans experienced and used by other gas utilities for similar structures. Most of the life spans result in probable retirement dates that are many years in the future. As a result, the retirement of these structures is not yet subject to specific management plans. Such plans would be premature. At the appropriate time, studies of the economics of rehabilitation and continued use or retirement of the structure will be analyzed and the results incorporated in the estimation of the structure's life span.

Q. Are the factors considered in your estimates of service life presented in Exhibit No. 109, Schedule No. 1, Attachment A?

A. Yes. A discussion of the factors considered in the estimation of service lives is presented by account on pages III-2 through III-8 of Exhibit No. 109, Schedule No. 1, Attachment A.

Q. Were there any material changes to life characteristics as a result of this rate proceeding?

A. No. There was no material change in the life estimate for plant accounts or subaccounts in this rate proceeding. All life estimates were based on the recent annual depreciation reports when the service life studies were conducted.

However, the probable retirement date for the Blackhawk Storage Facility was changed from 2035 to 2025 to reflect new plans for the site.

Q. Please outline the contents of Exhibit No. 109, Schedule No. 1, Attachment A.

A. Exhibit No. 109, Schedule No. 1, Attachment A is presented in eight parts. Part I, Introduction, sets forth the scope and basis of the study. Part II, Estimation of Survivor Curves, includes a description of the Iowa Curves and the formulation of the retirement rate method. Part III, Service Life Considerations, and Part IV, Calculation of Annual and Accrued Depreciation, include a description of the judgment utilized for life parameters and the explanation of depreciation procedures.

Part V, Results of Study, presents a description of the results and summaries of the depreciation calculations. Part VI, Service Life Statistics, presents the graphs and tables which relate to the service life study. Part VII, Detailed Depreciation Calculations, sets forth the detailed depreciation calculations by account. Part VIII, Experienced and Estimated Net Salvage, presents the cost of removal and gross salvage by account for the years 2011 through 2015.

Table 1, pages V-4 through V-6 presents the estimated survivor curve, the original cost at November 30, 2016, and the book reserve and calculated annual depreciation for each account or subaccount of Gas Plant. Table 2, pages V-7 and V-8 presents the bring forward to November 30, 2016, of the book depreciation reserve as of November 30, 2015. Table 3 on pages V-9 and V-10 sets forth the calculation of the annual accruals used in the bringforward.

Table 4, page V-11, presents the experienced and estimated net salvage during the five-year period, 2011 through 2015.

The section beginning on page VI-1 presents the results of the retirement rate analyses prepared as the historical bases for the service life estimates. The section beginning on page VII-1 presents the depreciation calculations related to original cost. The tabulation on pages VII-3 through VII-6 presents the cumulative depreciated original cost by year installed. The tabulations on pages VII-8 through VII-73 present the calculation of annual depreciation by vintage by account for each depreciable group of utility plant.

Q. Please outline the contents of Exhibit No. 109, Schedule No. 1, Attachment B.

A. Exhibit No. 109, Schedule No. 1, Attachment B includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of December 31, 2017. The descriptions and explanations presented in Exhibit No. 109, Schedule No. 1, Attachment A are also applicable to the depreciation calculations presented in Exhibit No. 109, Schedule No. 1, Attachment B. The graphs and tables related to service life presented in Exhibit No. 109, Schedule No. 1, Attachment A also support the service life estimates used in Exhibit No. 109, Schedule No. 1, Attachment B inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of December 31, 2017, are organized and presented in the same manner as those as of November 30, 2016.

Q. Please outline the contents of Exhibit No. 9.

A. Exhibit No. 9 includes a description of the results, summaries of the depreciation calculations, and the detailed depreciation calculations as of November 30, 2015. The descriptions and explanations presented in Exhibit No. 109, Schedule No. 1, Attachment A are also applicable to the depreciation calculations presented in Exhibit No. 9. The graphs and tables related to service life presented in Exhibit No. 109, Schedule No. 1, Attachment A also support the service life estimates used in Exhibit No. 9, inasmuch as the estimates are the same for both test years. The summary tables and detailed depreciation calculations as of November 30, 2015, are organized and presented in the same manner as those as of November 30, 2016.

Q. Please use an example to illustrate the manner in which the study is presented in Exhibit Nos. 9, and 109.

A. I will use Account 376, Mains, as my example, inasmuch as it is the largest depreciable group and represents 65 percent of the original cost of depreciable gas plant as of November 30, 2016.

The retirement rate method was used to analyze the survivor characteristics of this group. The life tables for the 1939-2011 and 1977-2011 experience bands are presented on pages VI-50 through VI-57 of Exhibit No. 109, Schedule No. 1, Attachment A. The life tables, or original survivor curve, are plotted along with the estimated smooth survivor curve, the 72-R1.5, on page VI-49.

The calculations of the annual depreciation related to the original cost at November 30, 2015, of gas plant are presented by type main on pages II-31 through II-37 of Exhibit No. 9. The calculation is based on the 72-R1.5 survivor curve, the attained age, and the allocated book reserve. The calculations at November 30, 2016, are presented by type main on pages VII-31 through VII-36 of Exhibit No. 109, Schedule No. 1, Attachment A and are based in part on the bringforward of the book reserve. Also, the calculations at December 31, 2017 are presented by type main on pages II-31 through II-36 of Exhibit No. 109, Schedule No. 1, Attachment B and are based in part on the bringforward of the book reserve. The tabulations in Exhibit Nos. 9 and 109 set forth the installation year, the original cost, calculated accrued depreciation, allocated book reserve, future accruals, remaining life and annual accrual. The totals are brought forward to Table 1 on page I-3 in Exhibit No. 9, page V-4 in Exhibit No. 109, Schedule No. 1, Attachment A and on page I-3 in Exhibit No. 109, Schedule No. 1, Attachment B.

Q. In what manner is net salvage incorporated in the depreciation calculations?

A. As stated on page IV-9 of Exhibit No. 109, Schedule No. 1, Attachment A, no adjustment for net salvage was made to the calculated annual depreciation amounts. The total calculated annual depreciation set forth on page I-6 of Exhibit No. 9, page V-11 of Exhibit No. 109, Schedule No. 1, Attachment A and on page I-10 of Exhibit No. 109, Schedule No. 1, Attachment B should include an addition for the amortization of negative net salvage in accordance with the practice of this Commission. The amortization is based on experience during the period 2010 through 2014 for the calculation as of November 30, 2015, and on experience during the period 2011 through November 30, 2015, plus estimates for the last month of 2015 for the calculation as of November 30, 2016.

The amortization for the December 31, 2017 calculation is based on experience during the period 2012 through November 30, 2015, plus estimates for the period December 2015 through December 2016. The amounts of the five-year amortizations are calculated in Table 2 on page I-6 of Exhibit No. 9, in Table 4 on page V-11 of Exhibit No. 109, Schedule No. 1, Attachment A and in Table 4 on page I-10 of Exhibit No. 109, Schedule No. 1, Attachment B.

Q. Have you provided a monthly bringforward to December 31, 2017, of the book depreciation reserve as of November 30, 2016?

A. Yes, Exhibit JJS-01 at the end of this testimony provides the monthly detail of the book depreciation reserve and the calculated depreciation. This exhibit agrees with the fully forecasted rate year reserve balance as shown on Exhibit No. 109, Schedule No. 1, Attachment B, Table 1 on pages I-3 through I-5.

Q. Does this complete your testimony at this time?

A. Yes, it does.

APPENDIX A

Q. Please state your name.

A. My name is John J. Spanos.

Q. What is your educational background?

A. I have Bachelor of Science degrees in Industrial Management and Mathematics from Carnegie-Mellon University and a Master of Business Administration from York College.

Q. Do you belong to any professional societies?

A. Yes. I am a member and current President of the Society of Depreciation Professionals and a member of the American Gas Association/Edison Electric Institute Industry Accounting Committee.

Q. Do you hold any special certification as a depreciation expert?

A. Yes. The Society of Depreciation Professionals has established national standards for depreciation professionals. The Society administers an examination to become certified in this field. I passed the certification exam in September 1997 and was recertified in August 2003, February 2008 and January 2013.

Q. Please outline your experience in the field of depreciation.

A. In June 1986, I was employed by Gannett Fleming Valuation and Rate Consultants, Inc. as a Depreciation Analyst. During the period from June 1986 to December 1995, I took part in the preparation of numerous depreciation and original cost studies for utility companies in various industries. Depreciation studies of telephone companies were performed for United Telephone of Pennsylvania, United Telephone of New Jersey and Anchorage Telephone Utility. My work in the railroad industry included depreciation studies for Union Pacific

Railroad, Burlington Northern Railroad and Wisconsin Central Transportation Corporation.

Assignments in the electric industry included depreciation studies for Chugach Electric Association, The Cincinnati Gas and Electric Company, The Union Light, Heat & Power Company, Northwest Territories Power Corporation and the City of Calgary - Electric System. Pipeline industry assignments included studies for TransCanada Pipelines Limited, Trans Mountain Pipe Line Company Ltd., Interprovincial Pipe Line Inc., Nova Gas Transmission Limited and Lakehead Pipeline Company.

My work for the gas industry included depreciation studies for Columbia Gas of Pennsylvania, Columbia Gas of Maryland, The Peoples Natural Gas Company, T. W. Phillips Gas & Oil Company, The Cincinnati Gas and Electric Company, The Union Light, Heat & Power Company, Lawrenceburg Gas Company and Penn Fuel Gas, Inc. Assignments in the water industry included depreciation studies for Indiana-American Water Company, Consumers Pennsylvania Water Company and The York Water Company; and depreciation and original cost studies for Philadelphia Suburban Water Company and Pennsylvania-American Water Company.

My participation in each of the above studies included assembly and analysis of historical and simulated data, field reviews, the development of preliminary estimates of service life and net salvage, calculations of annual depreciation, and the preparation of reports for submission to state or provincial public utility commissions or federal regulatory agencies. I performed these studies under the general direction of William M. Stout, P.E., the President of Gannett Fleming Valuation and Rate Consultants, Inc.

In January 1996, I was assigned to the position of Supervisor of Depreciation Studies. In July 1999, I was promoted to the position of Manager, Depreciation and Valuation Studies. In December 2000, I was promoted to the position as Vice-President of Gannett Fleming Valuation and Rate Consultants, Inc. and in April 2012, I was promoted to my present position as Senior Vice President of the Valuation and Rate Division of Gannett Fleming, Inc. (now doing business as Gannett Fleming Valuation and Rate Consultants, LLC). In my current position I am responsible for conducting all depreciation, valuation and original cost studies, including the preparation of final exhibits and responses to data requests for submission to the appropriate regulatory bodies.

Since January 1996, I have conducted depreciation studies similar to those previously listed including assignments for Pennsylvania-American Water Company; Aqua Pennsylvania; Kentucky-American Water Company; Virginia-American Water Company; Indiana-American Water Company; Hampton Water Works Company; Omaha Public Power District; Enbridge Pipe Line Company; Inc.; Columbia Gas of Virginia, Inc.; Virginia Natural Gas Company National Fuel Gas Distribution Corporation - New York and Pennsylvania Divisions; The City of Bethlehem - Bureau of Water; The City of Coatesville Authority; The City of Lancaster - Bureau of Water; Peoples Energy Corporation; The York Water Company; Public Service Company of Colorado; Enbridge Pipelines; Enbridge Gas Distribution, Inc.; Reliant Energy-HLP; Massachusetts-American Water Company; St. Louis County Water Company; Missouri-American Water

Company; Chugach Electric Association; Alliant Energy; Oklahoma Gas & Electric Company; Nevada Power Company; Dominion Virginia Power; NUI-Virginia Gas Companies; Pacific Gas & Electric Company; PSI Energy; NUI - Elizabethtown Gas Company; Cinergy Corporation – CG&E; Cinergy Corporation – ULH&P; Columbia Gas of Kentucky; South Carolina Electric & Gas Company; Idaho Power Company; El Paso Electric Company; Aqua North Carolina; Aqua Ohio; Aqua Texas, Inc.; Ameren Missouri; Central Hudson Gas & Electric; Centennial Pipeline Company; CenterPoint Energy-Arkansas; CenterPoint Energy – Oklahoma; CenterPoint Energy – Entex; CenterPoint Energy - Louisiana; NSTAR – Boston Edison Company; Westar Energy, Inc.; United Water Pennsylvania; PPL Electric Utilities; PPL Gas Utilities; Wisconsin Power & Light Company; TransAlaska Pipeline; Avista Corporation; Northwest Natural Gas; Allegheny Energy Supply, Inc.; Public Service Company of North Carolina; South Jersey Gas Company; Duquesne Light Company; MidAmerican Energy Company; Laclede Gas; Duke Energy Company; E.ON U.S. Services Inc.; Elkton Gas Services; Anchorage Water and Wastewater Utility; Kansas City Power and Light; Duke Energy North Carolina; Duke Energy South Carolina; Monongahela Power Company; Potomac Edison Company; Duke Energy Ohio Gas; Duke Energy Kentucky; Duke Energy Indiana; Northern Indiana Public Service Company; Tennessee-American Water Company; Columbia Gas of Maryland; Bonneville Power Administration; NSTAR Electric and Gas Company; EPCOR Distribution, Inc.; B. C. Gas Utility, Ltd; Entergy Arkansas; Entergy Texas; Entergy Mississippi; Entergy Louisiana; Entergy Gulf States Louisiana; the Borough of Hanover; Louisville Gas and Electric Company; Kentucky Utilities Company; Madison Gas and Electric; Central Maine Power; PEPCO; PacifiCorp; Minnesota Energy Resource Group; Jersey Central Power & Light Company; Cheyenne Light, Fuel and Power Company; United Water Arkansas; Central Vermont Public Service Corporation; Green Mountain Power; Portland General Electric Company; Atlantic City Electric; Nicor Gas Company; Black Hills Power; Black Hills Colorado Gas; Black Hills Kansas Gas; Black Hills Service Company; Black Hills Utility Holdings; Public Service Company of Oklahoma; City of Dubois; Peoples Gas Light and Coke Company; North Shore Gas Company; Connecticut Light and Power; New York State Electric and Gas Corporation; Rochester Gas and Electric Corporation and Greater Missouri Operations. My additional duties include determining final life and salvage estimates, conducting field reviews, presenting recommended depreciation rates to management for its consideration and supporting such rates before regulatory bodies.

Q. What is the extent of your formal instruction with respect to utility plant depreciation?

A. I have completed the "Techniques of Life Analysis", "Techniques of Salvage and Depreciation Analysis", "Forecasting Life and Salvage", "Modeling and Life Analysis Using Simulation" and "Managing a Depreciation Study" programs conducted by Depreciation Programs, Inc. Also, I have completed the "Introduction to Public Utility Accounting" program conducted by the American Gas Association.

Q. Have you previously testified on public utility ratemaking matters?

A. Yes. I have submitted testimony to the Pennsylvania Public Utility Commission; the Commonwealth of Kentucky Public Service Commission;

the Public Utilities Commission of Ohio; the Nevada Public Utility Commission; the Public Utilities Board of New Jersey; the Missouri Public Service Commission; the Massachusetts Department of Telecommunications and Energy; the Alberta Energy & Utility Board; the Idaho Public Utility Commission; the Louisiana Public Service Commission; the State Corporation Commission of Kansas; the Oklahoma Corporate Commission; the Public Service Commission of South Carolina; Railroad Commission of Texas – Gas Services Division; the New York Public Service Commission; Illinois Commerce Commission; the Indiana Utility Regulatory Commission; the California Public Utilities Commission; the Federal Energy Regulatory Commission ("FERC"); the Arkansas Public Service Commission; the Public Utility Commission of Texas; Maryland Public Service Commission; Washington Utilities and Transportation Commission; The Tennessee Regulatory Commission; the Regulatory Commission of Alaska; Minnesota Public Utility Commission; Utah Public Service Commission; District of Columbia Public Service Commission; the Mississippi Public Service Commission; Delaware Public Service Commission; Virginia State Corporation Commission; Colorado Public Utility Commission; Oregon Public Utility Commission; South Dakota Public Utilities Commission; Wisconsin Public Service Commission; Wyoming Public Service Commission; Maine Public Utility Commission; Iowa Utility Board;

Connecticut Public Utilities Regulatory Authority; New Mexico Public Regulation Commission and the North Carolina Utilities Commission.

RESERVE BRINGFORWARD

umber of months for accrual calculation = 12 mber of months in FFTY = 13

PROJECTED 16 PROJECTED 2017

Account	2016 NOV 30 Begin. Balance	Accrual Rates 2016	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2011-2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2012-2016	2016 DECEMBER Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	1,931
351.20	1,067,831	7.86			122			122	20,900	10	20,910	0	0	0	1,088,741
352 01	799,118	0 00							0	0	0	0	0	0	799,118
352.02	168,680	0.00							0	0	0	0	0	0	168,680
352.10	206,932	0.00							0	0	0	0	0	0	206,932
353.00	405,288	0 00							0	0	0	0	0	0	405,288
354.00	651,798	3.37							2,550	0	2,550	437	0	0	653,911
355 00	123,010	0.00							0	0	0	0	0	0	123,010
374 40	657,837	1 74	0 13		1,626	0.13		2,205	3,763	136	3,898	1,958	255	0	659,523
374 50	1,601,503	1 31							3,537	0	3,537	0	0	0	1,605,040
375.34	1,327,973	2.12	0.65		19,666	0 61		21,838	9,052	1,639	10,690	3,315	2,155	0	1,333,194
375 60	73,641	0.98			218			218	72	18	90	0	0	0	73,731
375.70	2,332,164	3.31	0 59		5,449	0 59		16,308	21,004	454	21,458	7,670	4,525	0	2,341,427
375 80	6,508	2.00							28	0	28	0	0	0	6 536
376 00	194,534,832	2.05	0.15		1,109,526	0 14		1,295,637	2,151,625	92,461	2,244,086	1,267,436	190,115	0	195,321,367
378 00	10,020,157	3.24	0 39		120,627	0 44		124,281	119,169	10,052	129,221	19,213	7,493	0	10,122,672
379.10	93,180	3.17			18			18	373	2	374	0	0	0	93,554
380 00	111,536,567	2 84	0 60		3,154,138	0 54		2,710,597	1,061,214	262,845	1,324,059	333,996	200,398	0	112,326,232
381 00	15,673,710	2.45		0.01	(6,464)		0.02	(6,534)	74,173	(539)	73,635	10,427	0	104	15,737,022
381 10	8,582,181	7.36							146,109	0	146,109	445	0	0	8,727,845
382.00	11,909,425	1.94							58,865	0	58,865	10,291	0	0	11,957,999
383 00	3,567,106	2 59							24,616	0	24,616	4,836	0	0	3,586,886
384 00	2,972,034	1 73							5,572	0	5,572	0	0	0	2,977,606
385.00	2,981,725	3.78	0 20		40,219	0 21		34,434	20,212	3,352	23,564	1,266	253	0	3,003,770
387 00	75,343	2.83			5,397				316	450	765	0	0	0	76,108
387 40	839,236	4.94			530			488	17,843	44	17,887	0	0	0	857,123
387.50	363,074	11 76							27,741	0	27,741	0	0	0	390,815
390.10	85,422	2.10							210	0	210	0	0	0	85,632
391 10	1,791,600	4 10							12,469	0	12,469	260,946	0	0	1,543,123
391.11	13,746	4 56							93	0	93	0	0	0	13,839
391 12	2,520,633	8.93							18,363	0	18,363	1,898,784	0	0	640,212
392.00	53,268	13.50			(10,337)			(8,896)	1,097	(861)	236	0	0	0	53,504
393.00	16,675	0.00							0	0	0	2,300	0	0	14,375
394 00	5,797,220	3.73							43,747	0	43,747	158,166	0	0	5,682,801
394 12	1,953,286	0 01							16	0	16	0	0	0	1,953,302
395 00	35,023	3.55							129	0	129	13,946	0	0	21,206
396.00	1,367,642	1 49			(29,680)			(20,934)	1,782	(2,473)	(691)	0	0	0	1,366 951
397.10	163,625	0 00							5,206	0	5,206	168,831	0	0	0
397.50	884,202	11 10			5,881			5,881	18,656	490	19,146	0	0	0	903 348
398 00	199,269	6.71							4,716	0	4,716	38,545	0	0	165,440
303.00	8,753,916								254,588	0	254,588	666,156	0	0	8,342,348
305.00	0								0	0	0	0	0	0	0
362.00	0								0	0	0	0	0	0	0
362.10	(1,686,454)				115,460			373,852	0	9,622	9,622	0	0	0	(1,676,832)
374.20	179,478				(30.727)			(30,727)	0	(2,561)	(2,561)	0	0	0	176,917
375.71	740,882								29,015	0	29,015	21,827	0	0	748 070
389.20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,158,821	375,139	4,533,961	4,890,790	405,194	104	394,680,298

RESERVE BRINGFORWARD

umber of months for accrual calculation = 12 umber of months in FFTY = 13

PROJECTED 16 PROJECTED 2017

Account	2016 NOV 30 Begin. Balance	Accrual Rates 2016	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2011-2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2012-2016	2017 JANUARY Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,931	0 00							0	0	0	0	0	0	1,931
351.20	1,067,831	7.86			122			122	20,900	10	20,910	0	0	0	1,109 652
352.01	799.118	0 00							0	0	0	0	0	0	799.118
352.02	168,680	0.00							0	0	0	0	0	0	168,680
352.10	206,932	0.00							0	0	0	0	0	0	206,932
353.00	405,288	0.00							0	0	0	0	0	0	405,288
354 00	651,798	3.37							2,559	0	2,559	188	0	0	656 283
355.00	123,010	0.00							0	0	0	0	0	0	123,010
374 40	657,837	1.74	0.13		1,626	0.13		2.205	3,784	184	3,968	963	125	0	662,402
374.50	1,601,503	1.31							3,537	0	3.537	0	0	0	1,608,576
375.34	1,327.973	2.12	0.65		19,666	0 61		21,838	9,095	1,820	10,915	1,522	928	0	1,341,659
375 60	73,641	0.98			218			218	72	18	90	0	0	0	73,821
375 70	2,332,164	3 31	0 59		5,449	0 59		16,308	21,132	1,359	22,491	1,364	805	0	2,361,749
375.80	6,508	2 00							28	0	28	0	0	0	6,563
376 00	194,534,832	2.05	0.15		1,109,526	0.14		1,295,637	2,168,245	107,970	2,276,214	633,371	88,672	0	196,875,538
378.00	10,020,157	3 24	0.39		120,627	0.44		124,281	119,604	10,357	129,961	12,261	5,395	0	10,234,977
379 10	93,180	3.17			18			18	373	2	374	0	0	0	93 929
380 00	111,536,567	2.84	0.60		3.154,138	0.54		2,710,597	1,067,089	225,883	1,292,972	151,022	81,552	0	113,386,631
381.00	15,673,710	2.45		0 01	(6.464)		0 02	(6.534)	74,336	(545)	73.791	5.125	0	103	15,805,791
381 10	8,582,181	7.36							146.123	0	146.123	0	0	0	8,873,969
382 00	11,909,425	1.94							58,992	0	58,992	5,140	0	0	12,011,851
383 00	3,587,106	2.59							24,697	0	24,697	2,485	0	0	3,609,098
384.00	2,972 034	1 73							5.572	0	5,572	0	0	0	2,983,177
385.00	2,981.725	3.78	0.20		40,219	0 21		34,434	20,242	2.870	23,111	568	119	0	3,026.194
387.00	75,343	2.83			5,397				316	0	316	0	0	0	76,424
387.40	839,236	4.94			530			488	17,843	41	17,884	0	0	0	875,007
387.50	363,074	11 76							28,184	0	28.184	0	0	0	418,999
390.10	85,422	2.10							210	0	210	0	0	0	85,842
391 10	1,791,600	4.10							12,023	0	12,023	0	0	0	1,555,146
391 11	13,746	4 56							93	0	93	0	0	0	13,932
391 12	2,520,633	8.93							11,298	0	11,298	0	0	0	651,510
392.00	53,268	13 50			(10,337)			(8,896)	1,097	(741)	356	0	0	0	53 860
393.00	16.675	0.00							0	0	0	0	0	0	14,375
394.00	5,797,220	3 73							43,618	0	43,618	0	0	0	5,726.419
394.12	1,953,286	0.01							16	0	16	0	0	0	1,953,319
395 00	35,023	3 55							109	0	109	0	0	0	21,315
396 00	1,367,642	1 49			(29,680)			(20,934)	1,782	(1,745)	38	0	0	0	1,366,989
397 10	163,625	0 00							0	0	0	0	0	0	0
397 50	884,202	11.10			5,881			5,881	19,042	490	19 532	0	0	0	922,880
398 00	199,269	6.71							4.631	0	4,631	0	0	0	170,071
303.00	8,753,916								254,588	0	254,588	0	0	0	8,596,936
305 00	0								0	0	0	0	0	0	0
362.00	0								0	0	0	0	0	0	0
362 10	(1,686,454)				115,460			373,852	0	31,154	31,154	0	0	0	(1,645,678)
374 20	179,478				(30,727)			(30,727)	0	(2,561)	(2,561)	0	0	0	174,357
375.71	740,882								29,015	0	29,015	1,329	0	0	775,755
389.20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,170,244	376,566	4,546,810	815,338	177,596	103	398,234,276

RESERVE BRINGFORWARD

ımber of months for accrual calculation = 12 ımber of months in FFTY = 13

			PROJECTED 16			PROJECTED 2017									
	2016	Accrual			5-yr			'5-yr	2017						
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	FEBRUARY						
Account	Begin. Balance	2016 .	% of Rets	% of Rets	2011-2015	% of Rets	% of Rets	2012-2016	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	1,931
351.20	1,067 831	7.86			122			122	20,900	10	20,910	0	0	0	1,130,562
352 01	799,118	0.00							0	0	0	0	0	0	799,118
352 02	168,680	0 00							0	0	0	0	0	0	168,680
352.10	206.932	0 00							0	0	0	0	0	0	206,932
353.00	405.288	0.00							0	0	0	0	0	0	405 288
354.00	651,798	3 37							2,565	0	2,565	194	0	0	658,654
355.00	123,010	0.00							0	0	0	0	0	0	123,010
374.40	657,837	1 74	0 13		1,626	0.13		2,205	3,799	184	3.983	1,053	137	0	665,195
374 50	1,601,503	1 31							3,537	0	3,537	0	0	0	1,612,113
375 34	1,327,973	2.12	0.65		19,666	0 61		21,838	9,124	1.820	10,944	1,619	988	0	1,349,996
375 60	73,641	0 98			218			218	72	18	90	0	0	0	73,910
375 70	2,332.164	3 31	0.59		5,449	0 59		16.308	21,170	1,359	22,529	1,364	805	0	2,382,110
375 80	6,508	2.00							28	0	28	0	0	0	6,591
376 00	194,534,832	2 05	0.15		1,109,526	0.14		1,295,637	2,179,637	107,970	2,287,607	669,596	93,743	0	198,399,805
378.00	10,020.157	3.24	0.39		120,627	0 44		124,281	119,950	10,357	130,307	12,785	5,625	0	10,346,874
379 10	93,180	3.17			18			18	373	2	374	0	0	0	94,303
380 00	111,536,567	2 84	0.60		3 154,138	0 54		2,710.597	1,070,835	225,883	1,296,718	158,225	85,442	0	114,439,682
381 00	15,673 710	2.45		0 01	(6,464)		0 02	(6,534)	74,446	(545)	73,902	5,423	0	108	15,874,378
381 10	8,582,181	7.36							146,123	0	146,123	0	0	0	9,020,092
382.00	11,909,425	1 94							59,080	0	59,080	5,472	0	0	12,065,460
383 00	3,567,106	2.59							24,754	0	24,754	2.672	0	0	3,631,180
384.00	2.972,034	1 73							5,572	0	5,572	0	0	0	2,988,749
385 00	2,981,725	3 78	0 20		40,219	0 21		34,434	20,261	2,870	23,130	599	126	0	3,048,600
387.00	75,343	2 83			5,397				316	0	316	0	0	0	76,740
387 40	839,236	4.94			530			488	17,843	41	17,884	0	0	0	892,891
387.50	363,074	11 76							29,095	0	29,095	0	0	0	448,093
390 10	85,422	2.10							210	0	210	0	0	0	86,052
391 10	1,791,600	4 10							12,023	0	12,023	0	0	0	1,567,169
391 11	13,746	4.56							93	0	93	0	0	0	14,024
391.12	2,520,633	8.93							11,298	0	11,298	0	0	0	662,808
392.00	53,268	13 50			(10,337)			(8,896)	1,097	(741)	356	0	0	0	54,216
393 00	16,675	0 00							0	0	0	0	0	0	14.375
394 00	5.797,220	3 73							43,851	0	43,851	0	0	0	5,770,270
394.12	1,953,286	0 01							16	0	16	0	0	0	1,953,335
395 00	35,023	3 55							109	0	109	0	0	0	21,424
396.00	1.367,642	1 49			(29,680)			(20,934)	1,782	(1,745)	38	0	0	0	1,367,027
397 10	163,625	0 00							0	0	0	0	0	0	0
397.50	884,202	11 10			5,881			5,881	19,736	490	20,226	0	0	0	943,106
398.00	199,269	6 71							4,654	0	4,654	0	0	0	174,725
303 00	8,753,916								254,588	0	254,588	0	0	0	8,851,523
305 00	0								0	0	0	0	0	0	0
362 00	0								0	0	0	0	0	0	0
362 10	(1,686,454)				115.460			373,852	0	31,154	31.154	0	0	0	(1,614,524)
374.20	179.478				(30,727)			(30,727)	0	(2,561)	(2,561)	0	0	0	171,796
375 71	740.882								29,015	0	29,015	1,329	0	0	803,441
389.20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,187,951	376,566	4,564,516	860,331	186,865	108	401,751,704

RESERVE BRINGFORWARD

ımber of months for accrual calculation = 12 ımber of months in FFTY = 13

PROJECTED 16 PROJECTED 2017

Account	2016 NOV 30 Begin. Balance	Accrual Rates 2016	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2011-2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2012-2016	2017 MARCH Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	1,931
351.20	1,067,831	7.86			122			122	20,900	10	20,910	0	0	0	1,151,473
352.01	799,118	0.00							0	0	0	0	0	0	799,118
352 02	168,680	0.00							0	0	0	0	0	0	168,680
352.10	206,932	0.00							0	0	0	0	0	0	206,932
353.00	405,288	0.00							0	0	0	0	0	0	405,288
354 00	651,798	3.37							2,572	0	2,572	293	0	0	680,932
355.00	123,010	0.00							0	0	0	0	0	0	123,010
374 40	657,837	1.74	0.13		1,626	0.13		2,205	3,817	184	4,001	1,322	172	0	667,702
374 50	1,601,503	1 31							3,537	0	3,537	0	0	0	1,615,649
375.34	1,327,973	2.12	0.65		19,666	0.61		21,838	9,159	1,820	10,978	2,229	1,360	0	1,357,385
375.60	73,641	0.98			218			218	72	18	90	0	0	0	74,000
375 70	2,332,164	3.31	0.59		5,449	0.59		16,308	21,209	1,359	22,568	1,364	805	0	2,402,509
375.80	6,508	2.00							28	0	28	0	0	0	6,618
376.00	194,534,832	2.05	0 15		1,109,526	0.14		1,295,637	2,194,337	107,970	2,302,307	1,011,709	141,639	0	199,548,763
378.00	10,020,157	3.24	0.39		120,627	0.44		124,281	120,386	10,357	130,743	18 749	8,250	0	10,450,618
379.10	93,180	3.17			18			18	373	2	374	0	0	0	94,677
380 00	111,536,567	2.84	0.60		3,154,138	0.54		2,710,597	1,075,521	225,883	1,301,404	228,628	123,459	0	115,388,998
381 00	15,673,710	2.45		0.01	(6,464)		0.02	(6,534)	74,582	(545)	74,038	7,594	0	152	15,940,974
381 10	8,582,181	7 36							146,123	0	146,123	0	0	0	9,166,215
382 00	11,909,425	1.94							59,188	0	59,188	7,509	0	0	12,117,138
383 00	3,567,106	2.59							24,823	0	24,823	3,552	0	0	3,652,450
384 00	2,972,034	1 73							5,572	0	5,572	0	0	0	2,994,321
385 00	2,981,725	3.78	0.20		40,219	0 21		34,434	20,284	2,870	23,154	850	179	0	3,070 725
387 00	75,343	2.83			5,397				316	0	316	0	0	0	77,055
387 40	839,236	4 94			530			488	17,843	41	17,884	0	0	0	910,774
387 50	363,074	11 76							30.526	0	30,526	0	0	0	478,619
390 10	85,422	2.10							210	0	210	0	0	0	86,262
391 10	1,791,600	4.10							12,023	0	12,023	0	0	0	1,579,193
391 11	13,746	4.56							93	0	93	0	0	0	14,117
391 12	2,520,633	8 93							11,298	0	11,298	0	0	0	674,106
392.00	53,268	13.50			(10,337)			(8,896)	1,097	(741)	356	0	0	0	54,572
393 00	16,675	0 00							0	0	0	0	0	0	14,375
394 00	5,797,220	3.73							44,217	0	44,217	0	0	0	5,814,488
394 12	1,953,286	0 01							16	0	16	0	0	0	1,953,351
395.00	35,023	3 55							109	0	109	0	0	0	21,532
396 00	1,367,642	1 49			(29,680)			(20,934)	1,782	(1,745)	38	0	0	0	1,367,065
397.10	163,625	0 00							0	0	0	0	0	0	0
397 50	884,202	11 10			5,881			5,881	20,826	490	21,316	0	0	0	964,422
398 00	199,269	6 71							4,678	0	4,678	0	0	0	179,403
303.00	8,753,916								254,588	0	254,588	612 266	0	0	8,493,845
305 00	0								0	0	0	0	0	0	0
362 00	0								0	0	0	0	0	0	0
362.10	(1,686,454)				115,460			373,852	0	31,154	31,154	0	0	0	(1,583,369)
374.20	179,478				(30,727)			(30,727)	0	(2,561)	(2,561)	0	0	0	169,236
375 71	740.882								29,015	0	29 015	1,329	0	0	831.126
389.20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,211,116	376,566	4,587,682	1,897,394	275,863	152	404,166,281

RESERVE BRINGFORWARD

ımber of months for accrual calculation = 12 ımber of months in FFTY = 13

PROJECTED 16 PROJECTED 2017

Account	2016 NOV 30 Begin. Balance	Accrual Rates 2016	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2011-2015	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2012-2016	2017 APRIL Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,931	0 00							0	0	0	0	0	0	1,931
351.20	1,067,831	7.86			122			122	20,900	10	20,910	0	0	0	1,172,383
352.01	799,118	0 00							0	0	0	0	0	0	799,118
352 02	168,680	0 00							0	0	0	0	0	0	168,680
352.10	206,932	0 00							0	0	0	0	0	0	206,932
353 00	405,288	0.00							0	0	0	0	0	0	405,288
354 00	651,798	3.37							2,583	0	2,583	454	0	0	663,061
355 00	123,010	0.00							0	0	0	0	0	0	123,010
374 40	657,837	1.74	0.13		1,626	0.13		2,205	3,838	184	4,022	1,547	201	0	669,976
374.50	1,601,503	1 31							3,537	0	3,537	0	0	0	1,619,186
375.34	1,327,973	2.12	0.65		19,666	0 61		21,838	9,206	1,820	11,026	3,054	1,863	0	1,363,494
375 60	73,641	0.98			218			218	72	18	90	0	0	0	74,090
375 70	2,332,164	3.31	0.59		5,449	0 59		16,308	21,247	1,359	22,606	1,364	805	0	2,422,946
375 80	6,508	2.00							28	0	28	0	0	0	6 646
376.00	194,534,832	2.05	0.15		1,109,526	0.14		1,295,637	2,217,237	107,970	2,325,207	1,607,494	225,049	0	200,041,427
378.00	10,020,157	3.24	0.39		120,627	0.44		124,281	121,033	10,357	131,390	28,069	12,350	0	10,541,589
379.10	93,180	3 17			18			18	373	2	374	0	0	0	95,051
380.00	111,536,567	2.84	0 60		3,154,138	0 54		2,710,597	1,082 355	225,883	1,308,238	335,610	181,229	0	116,180,397
381.00	15,673,710	2 45		0 01	(6,464)		0 02	(6,534)	74,773	(545)	74,229	10,669	0	213	16,004,746
381 10	8,582,181	7.36							146,152	0	146,152	908	0	0	9,311,459
382 00	11,909,425	1.94							59,335	0	59,335	10,234	0	0	12,166,239
383 00	3,567,106	2.59							24,913	0	24,913	4,601	0	0	3,672,762
384 00	2,972,034	1.73							5,572	0	5,572	0	0	0	2,999,893
385 00	2,981,725	3 78	0 20		40,219	0 21		34,434	20,318	2,870	23,187	1,218	256	0	3,092,438
387.00	75,343	2.83			5.397				316	0	316	0	0	0	77,371
387 40	839,236	4 94			530			488	17,843	41	17,884	0	0	0	928,658
387 50	363,074	11.76							31,879	0	31,879	0	0	0	510,498
390 10	85,422	2.10							210	0	210	0	0	0	86,473
391 10	1,791,600	4 10							12,023	0	12,023	0	0	0	1,591,216
391 11	13,746	4 56							93	0	93	0	0	0	14,210
391 12	2,520.633	8 93							11,298	0	11,298	0	0	0	685,404
392.00	53,268	13 50			(10,337)			(8,896)	1,097	(741)	356	0	0	0	54,927
393.00	16,675	0 00							0	0	0	0	0	0	14,375
394.00	5.797.220	3.73							44,564	0	44,564	0	0	0	5,859,051
394 12	1,953,286	0.01							16	0	16	0	0	0	1,953 368
395.00	35,023	3 55							109	0	109	0	0	0	21,641
396 00	1,367,642	1 49			(29,680)			(20,934)	1,782	(1,745)	38	0	0	0	1,367,103
397.10	163,625	0 00							0	0	0	0	0	0	0
397 50	884,202	11.10			5,881			5,881	21,857	490	22,347	0	0	0	986,769
398 00	199,269	6 71							4,701	0	4,701	0	0	0	184,104
303 00	8,753,916								254,588	0	254,588	743,917	0	0	8,004,516
305.00	0								0	0	0	0	0	0	0
362 00	0								0	0	0	0	0	0	0
362.10	(1,686,454)				115,460			373,852	0	31,154	31,154	0	0	0	(1,552,215)
374.20	179,478				(30,727)			(30,727)	0	(2,561)	(2,561)	0	0	0	166,675
375.71	740,882								29,015	0	29,015	1,329	0	0	858,812
389.20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,244,859	376,566	4,621,425	2,750,468	421,754	213	405,615,698

RESERVE BRINGFORWARD

ımber of months for accrual calculation = 12 ımber of months in FFTY = 13

PROJECTED 16 PROJECTED 2017

Account	2016 NOV 30 Begin. Balance	Accrual Rates 2016	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2011-2015	COR % of Rets	Salvage % of Rets	'5-yr Amort of NS 2012-2016	2017 MAY Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	1,931
351.20	1,067,831	7.86			122			122	20,900	10	20,910	0	0	0	1,193,294
352.01	799,118	0.00							0	0	0	0	0	0	799,118
352.02	168,680	0.00							0	0	0	0	0	0	168,680
352.10	206,932	0 00							0	0	0	0	0	0	206,932
353 00	405,288	0 00							0	0	0	0	0	0	405,288
354 00	651,798	3.37							2,597	0	2,597	518	0	0	665,140
355.00	123,010	0.00							0	0	0	0	0	0	123,010
374.40	657,837	1 74	0.13		1,626	0.13		2,205	3,863	184	4,047	1,780	231	0	672,011
374 50	1,601,503	1.31							3,537	0	3,537	0	0	0	1,622,722
375.34	1,327,973	2.12	0.65		19,666	0.61		21,838	9,266	1,820	11,085	3,497	2,133	0	1,368,950
375 60	73,641	0 98			218			218	72	18	90	0	0	0	74,180
375.70	2,332,164	3 31	0.59		5,449	0 59		16,308	21,286	1,359	22,645	1,364	805	0	2,443,422
375 80	6,508	2.00							28	0	28	0	0	0	6,673
376.00	194 534,832	2.05	0.15		1,109,526	0.14		1,295,637	2,247,463	107,970	2,355,432	1,849,543	258,936	0	200,288,380
378.00	10,020,157	3.24	0.39		120,627	0.44		124,281	121,864	10,357	132,221	32,066	14,109	0	10 627,634
379.10	93,180	3.17			18			18	373	2	374	0	0	0	95,426
380.00	111,536,567	2.84	0.60		3,154,138	0 54		2,710,597	1,091,067	225,883	1,316,950	383,614	207,152	0	116,906,581
381.00	15 673,710	2.45		0 01	(6,464)		0 02	(6,534)	75,012	(545)	74,468	12,209	0	244	16,067,249
381 10	8,582,181	7.36							146,608	0	146,608	13,617	0	0	9,444.450
382 00	11,909,425	1.94							59,516	0	59,516	11,723	0	0	12,214,032
383.00	3,567,106	2.59							25,022	0	25,022	5,278	0	0	3,692.506
384 00	2,972,034	1 73							5,572	0	5.572	0	0	0	3,005,464
385 00	2,981.725	3.78	0.20		40,219	0.21		34,434	20,360	2,870	23,229	1,393	293	0	3,113,981
387.00	75,343	2.83			5,397				316	0	316	0	0	0	77,687
387.40	839,236	4.94			530			488	17,843	41	17,884	0	0	0	946,542
387 50	363.074	11.76							33,154	0	33,154	0	0	0	543,651
390 10	85,422	2.10							210	0	210	0	0	0	86,683
391 10	1,791,600	4.10							12,023	0	12.023	0	0	0	1,603,239
391.11	13,746	4 56							93	0	93	0	0	0	14,303
391 12	2,520,633	8.93							11,298	0	11,298	0	0	0	696,702
392.00	53.268	13.50			(10,337)			(8,896)	1,097	(741)	356	0	0	0	55,283
393 00	16,675	0.00							0	0	0	0	0	0	14,375
394 00	5.797,220	3 73							44,890	0	44,890	0	0	0	5,903,942
394 12	1,953,286	0 01							16	0	16	0	0	0	1,953,384
395 00	35.023	3 55							109	0	109	0	0	0	21 749
396 00	1,367,642	1 49			(29.680)			(20,934)	1,782	(1,745)	38	0	0	0	1,367,141
397.10	163,625	0.00							0	0	0	0	0	0	0
397.50	884.202	11.10			5,881			5,881	22,828	490	23,318	0	0	0	1,010.087
398.00	199,269	6.71							4,724	0	4,724	0	0	0	188,829
303.00	8,753,916								254,588	0	254,588	0	0	0	8,259,104
305.00	0								0	0	0	0	0	0	0
362.00	0								0	0	0	0	0	0	0
362 10	(1,686,454)				115,460			373,852	0	31,154	31.154	0	0	0	(1,521,061)
374.20	179,478				(30,727)			(30,727)	0	(2,561)	(2,561)	0	0	0	164,115
375 71	740,882								29,015	0	29.015	1,329	0	0	886.497
389.20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,288,387	376,566	4,664,953	2,317,931	483,658	244	407,479,306

RESERVE BRINGFORWARD

ımber of months for accrual calculation = 12 ımber of months in FFTY = 13

PROJECTED 16 PROJECTED 2017

Account	2016 NOV 30 Begin. Balance	Accrual Rates 2016	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2011-2015	COR % of Rets	Salvage % of Rets	5-yr Amort of NS 2012-2016	2017 JUNE Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	1,931
351.20	1,067,831	7.86			122			122	20,900	10	20,910	0	0	0	1,214,204
352.01	799,118	0 00							0	0	0	0	0	0	799,118
352 02	168,680	0.00							0	0	0	0	0	0	168,680
352.10	206,932	0.00							0	0	0	0	0	0	206,932
353 00	405,288	0 00							0	0	0	0	0	0	405,288
354.00	651,798	3 37							2,613	0	2,613	592	0	0	667,160
355 00	123,010	0.00							0	0	0	0	0	0	123 010
374.40	657,837	1.74	0.13		1,626	0.13		2,205	3,892	184	4,076	2,131	277	0	673,679
374 50	1,601,503	1.31							3,537	0	3,537	0	0	0	1,626 259
375 34	1,327,973	2.12	0.65		19,666	0 61		21,838	9,334	1,820	11,154	4,072	2,484	0	1,373,548
375.60	73,641	0.98			218			218	72	18	90	0	0	0	74,269
375 70	2,332,164	3 31	0.59		5,449	0 59		16,308	21,324	1,359	22,683	1,364	805	0	2,463,937
375.80	6,508	2.00							28	0	28	0	0	0	6,701
376 00	194,534,832	2 05	0.15		1,109,526	0.14		1,295,637	2,282,022	107,970	2,389,991	2,103,111	294,436	0	200 280,825
378 00	10,020,157	3 24	0.39		120,627	0.44		124,281	122,816	10,357	133,172	36,814	16,198	0	10,707,794
379.10	93,180	3.17			18			18	373	2	374	0	0	0	95,800
380 00	111,536,567	2.84	0.60		3,154,138	0.54		2,710,597	1,101,064	225,883	1,326,947	441,747	238,543	0	117,553,238
381.00	15,673,710	2.45		0 01	(6,464)		0 02	(6,534)	75,288	(545)	74,743	14,157	0	283	16,128,118
381 10	8,582,181	7.36							147,064	0	147,064	908	0	0	9,590,605
382 00	11,909,425	1 94							59,726	0	59,726	13,660	0	0	12,260,098
383.00	3,567,106	2 59							25,149	0	25,149	6,203	0	0	3,711,451
384 00	2,972,034	1 73							5,572	0	5,572	0	0	0	3,011,036
385 00	2,981,725	3 78	0.20		40,219	0 21		34,434	20,408	2,870	23,277	1,610	338	0	3,135,311
387.00	75,343	2.83			5,397				316	0	316	0	0	0	78,002
387.40	839,236	4 94			530			488	17,843	41	17,884	0	0	0	964,425
387.50	363,074	11.76							34,429	0	34,429	0	0	0	578,080
390.10	85,422	2.10							210	0	210	0	0	0	86,893
391.10	1,791,600	4 10							12,023	0	12,023	0	0	0	1,615,262
391 11	13,746	4 56							93	0	93	0	0	0	14,396
391 12	2,520,633	8 93							11,298	0	11,298	0	0	0	708,001
392.00	53,268	13.50			(10,337)			(8 896)	1,097	(741)	356	0	0	0	55,639
393 00	16,675	0.00							0	0	0	0	0	0	14,375
394.00	5,797,220	3 73							45,216	0	45,216	0	0	0	5,949,158
394 12	1,953,286	0.01							16	0	16	0	0	0	1,953,400
395 00	35,023	3 55							109	0	109	0	0	0	21,858
396.00	1,367,642	1 49			(29,680)			(20,934)	1,782	(1,745)	38	0	0	0	1,367,176
397 10	163,625	0.00							0	0	0	0	0	0	0
397.50	884,202	11.10			5,881			5.881	23,799	490	24,289	0	0	0	1,034,376
398.00	199,269	6.71							4,748	0	4,748	0	0	0	193,576
303 00	8,753,916								254,588	0	254,588	36,135	0	0	8,477,556
305.00	0								0	0	0	0	0	0	0
362.00	0								0	0	0	0	0	0	0
362.10	(1,686,454)				115,460			373,852	0	31,154	31,154	0	0	0	(1,489,906)
374.20	179,478				(30,727)			(30,727)	0	(2,561)	(2,561)	0	0	0	161,554
375 71	740,882								29,015	0	29 015	1,329	0	0	914,183
389.20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,337,760	376,566	4,714,326	2,663,833	553,081	283	408,977,000

RESERVE BRINGFORWARD

umber of months for accrual calculation = 12 umber of months in FFTY = 13

PROJECTED 16 PROJECTED 2017

	2016	Accrual			5-yr			'5-yr	2017						
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	JULY						
Account	Begin. Balance	2016	% of Rets	% of Rets	2011-2015	% of Rets	% of Rets	2012-2016	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	1,931
351 20	1,067,831	7.86			122			122	20,900	10	20,910	0	0	0	1,235,115
352.01	799.118	0.00							0	0	0	0	0	0	799,118
352 02	168,680	0.00							0	0	0	0	0	0	168,680
352.10	206,932	0 00							0	0	0	0	0	0	206,932
353.00	405,288	0 00							0	0	0	0	0	0	405,288
354 00	651,798	3.37							2,629	0	2,629	561	0	0	669,228
355 00	123.010	0.00							0	0	0	0	0	0	123,010
374 40	657,837	1 74	0.13		1,626	0.13		2,205	3,921	184	4,105	1,771	230	0	675,782
374.50	1,601,503	1.31							3,537	0	3,537	0	0	0	1,629.796
375.34	1,327,973	2.12	0.65		19,666	0 61		21,838	9,404	1,820	11,224	3,659	2,232	0	1,378,880
375.60	73,641	0 98			218			218	72	18	90	0	0	0	74,359
375.70	2,332,164	3.31	0 59		5,449	0.59		16,308	21,363	1,359	22,722	1,364	805	0	2,484,490
375.80	6,508	2.00							28	0	28	0	0	0	6,728
376 00	194,534,832	2.05	0.15		1,109,526	0.14		1,295,637	2,317,829	107,970	2,425,799	1,992.352	278,929	0	200,435,343
378 00	10,020,157	3.24	0 39		120,627	0.44		124,281	123.799	10.357	134,156	34.374	15,125	0	10,792,452
379 10	93,180	3.17			18			18	373	2	374	0	0	0	96.174
380.00	111,536,567	2.84	0.60		3,154.138	0 54		2,710,597	1,111,370	225,883	1,337,253	409.108	220,918	0	118,260,464
381 00	15,673,710	2.45		0.01	(6,464)		0 02	(6.534)	75,570	(545)	75,025	12.866	0	257	16,190,535
381.10	8,582.181	7.36							147,106	0	147,106	454	0	0	9,737,257
382 00	11,909.425	1.94							59,941	0	59,941	12.247	0	0	12.307,792
383 00	3.567,106	2.59							25,277	0	25,277	5,431	0	0	3,731,297
384.00	2,972,034	1 73							5,572	0	5,572	0	0	0	3,016,608
385 00	2,981.725	3.78	0.20		40,219	0.21		34,434	20,458	2,870	23,327	1.475	310	0	3,156,853
387 00	75,343	2.83			5,397				316	0	316	0	0	0	78,318
387 40	839,236	4 94			530			468	17,843	41	17,884	0	0	0	982,309
387.50	363,074	11 76							35,704	0	35,704	0	0	0	613,784
390.10	85,422	2.10							210	0	210	0	0	0	87,103
391 10	1,791,600	4.10							12,023	0	12,023	0	0	0	1,627,285
391.11	13,746	4.56							93	0	93	0	0	0	14,489
391 12	2,520,633	8.93							11,298	0	11,298	0	0	0	719,299
392 00	53 268	13 50			(10,337)			(8,896)	1,097	(741)	356	0	0	0	55,995
393.00	16,675	0 00							0	0	0	0	0	0	14.375
394 00	5,797,220	3.73							45.543	0	45,543	0	0	0	5,994,701
394 12	1,953,286	0.01							16	0	16	0	0	0	1,953,416
395 00	35,023	3.55							109	0	109	0	0	0	21,967
396 00	1,367.642	1 49			(29 680)			(20.934)	1,782	(1.745)	38	0	0	0	1,367,216
397 10	163,625	0.00							0	0	0	0	0	0	0
397.50	884,202	11 10			5,881			5,881	24,770	490	25,260	0	0	0	1,059,636
398 00	199,269	6.71							4,771	0	4,771	0	0	0	198,347
303.00	8.753,916								254,588	0	254,588	12,807	0	0	8 719,337
305 00	0								0	0	0	0	0	0	0
362.00	0								0	0	0	0	0	0	0
362.10	(1,686,454)				115,460			373,852	0	31.154	31.154	0	0	0	(1.458,752)
374.20	179,478				(30,727)			(30,727)	0	(2,561)	(2,561)	0	0	0	158,993
375.71	740,882								29,015	0	29,015	1,329	0	0	941,868
389 20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,388,325	376,566	4,764,890	2,489,798	518,549	257	410,733,801

RESERVE BRINGFORWARD

ımber of months for accrual calculation = 12 ımber of months in FFTY = 13

PROJECTED 16 PROJECTED 2017

	2016	Accrual			5-yr			'5-yr	2017						
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	AUGUST						
Account	Begin. Balance	2016	% of Rets	% of Rets	2011-2015	% of Rets	% of Rets	2012-2016	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350 20	1,931	0.00							0	0	0	0	0	0	1,931
351.20	1,067,831	7.86			122			122	20,900	10	20,910	0	0	0	1,256,025
352 01	799,118	0.00							0	0	0	0	0	0	799,118
352.02	168,680	0.00							0	0	0	0	0	0	168,680
352.10	206,932	0.00							0	0	0	0	0	0	206,932
353.00	405,288	0.00							0	0	0	0	0	0	405,288
354.00	651,798	3 37							2,645	0	2,645	517	0	0	671,356
355.00	123,010	0 00							0	0	0	0	0	0	123,010
374 40	657,837	1.74	0.13		1,626	0.13		2,205	3,948	184	4,132	1,861	242	0	677,811
374 50	1,601,503	1.31							3,537	0	3,537	0	0	0	1,633,332
375.34	1,327,973	2.12	0 65		19,666	0.61		21,838	9,469	1,820	11,289	3,556	2,169	0	1,384,444
375 60	73,641	0 98			218			218	72	18	90	0	0	0	74,449
375 70	2,332,164	3 31	0.59		5,449	0.59		16,308	21,401	1,359	22,760	1,364	805	0	2,505,082
375.80	6,508	2.00							28	0	28	0	0	0	6,756
376.00	194,534,832	2.05	0.15		1,109,526	0.14		1,295,637	2,351,980	107,970	2,459,950	1,913,650	267,911	0	200,713,731
378.00	10,020,157	3.24	0.39		120,627	0 44		124,281	124,719	10,357	135,075	32,142	14,142	0	10,881,243
379.10	93,180	3.17			18			18	373	2	374	0	0	0	96.549
380.00	111,536,567	2 84	0.60		3,154,138	0 54		2,710,597	1,120,997	225,883	1,346,880	385,696	208 276	0	119,013,372
381.00	15,673,710	2.45		0.01	(6,464)		0.02	(6.534)	75,834	(545)	75,289	12,362	0	247	16,253,709
381.10	8,582,181	7.36							147,548	0	147,548	13,617	0	0	9,871,189
382.00	11.909,425	1 94							60,141	0	60,141	11,929	0	0	12,356,003
383.00	3,567,106	2.59							25,397	0	25,397	5,417	0	0	3.751,277
384 00	2,972,034	1.73							5,572	0	5,572	0	0	0	3,022,179
385 00	2,981.725	3.78	0.20		40,219	0 21		34,434	20,504	2,870	23,374	1,406	295	0	3,178,526
387.00	75,343	2.83			5,397				316	0	316	0	0	0	78 634
387 40	839.236	4 94			530			488	17.843	41	17,884	0	0	0	1,000,193
387.50	363,074	11 76							36,979	0	36,979	0	0	0	650,763
390.10	85,422	2.10							210	0	210	0	0	0	87,313
391 10	1,791,600	4.10							12,023	0	12,023	0	0	0	1,639,309
391.11	13,746	4.56							93	0	93	0	0	0	14,581
391 12	2,520,633	8 93							11,298	0	11,298	0	0	0	730,597
392 00	53.268	13.50			(10,337)			(8,896)	1,097	(741)	356	0	0	0	56,351
393.00	16,675	0.00							0	0	0	0	0	0	14,375
394 00	5,797,220	3 73							45 869	0	45,869	0	0	0	6,040,570
394.12	1,953,286	0 01							16	0	16	0	0	0	1,953,433
395 00	35,023	3 55							109	0	109	0	0	0	22,075
396 00	1,367,642	1.49			(29 680)			(20,934)	1,782	(1,745)	38	0	0	0	1,367.254
397 10	163,625	0.00							0	0	0	0	0	0	0
397.50	884,202	11 10			5,881			5,881	25.741	490	26,231	0	0	0	1,085,867
398 00	199,269	6.71							4,794	0	4,794	0	0	0	203,141
303.00	8,753,916								254,588	0	254,588	0	0	0	8,973,925
305.00	0								0	0	0	0	0	0	0
362 00	0								0	0	0	0	0	0	0
362 10	(1,686,454)				115.460			373.852	0	31,154	31,154	0	0	0	(1,427,598)
374.20	179,478				(30,727)			(30.727)	0	(2,561)	(2,561)	0	0	0	156,433
375.71	740,882								29,015	0	29,015	1,329	0	0	969.554
389.20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,436,836	376,666	4,813,401	2,384,846	493,840	247	412,668,763

RESERVE BRINGFORWARD

ımber of months for accrual calculation = 12 ımber of months in FFTY = 13

Account	2016 NOV 30 Begin. Balance	Accrual Rates 2016	PROJECTED 16 COR % of Rets	PROJECTED 16 Salvage % of Rets	5-yr Amort of NS 2011-2015	PROJECTED 2017 COR % of Rets	PROJECTED 2017 Salvage % of Rets	'5-yr Amort of NS 2012-2016	2017 SEPTEMBER Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,931	0.00							0	0	0	0	0	0	1,931
351 20	1,067,831	7.86			122			122	20,900	10	20 910	0	0	0	1,276,936
352 01	799,118	0.00							0	0	0	0	0	0	799,118
352 02	168,680	0 00							0	0	0	0	0	0	168,680
352.10	206.932	0 00							0	0	0	0	0	0	206.932
353 00	405,288	0.00							0	0	0	0	0	0	405,288
354.00	651,798	3.37							2,659	0	2,659	493	0	0	673,522
355 00	123,010	0.00							0	0	0	0	0	0	123,010
374 40	657,837	1 74	0.13		1,626	0.13		2,205	3,977	184	4,161	2.077	270	0	679,624
374 50	1,601,503	1 31							3,537	0	3,537	0	0	0	1,636.869
375 34	1,327,973	2.12	0 65		19,666	0 61		21.838	9,534	1,820	11,354	3,634	2.217	0	1,389.948
375.60	73,641	0.98			218			218	72	18	90	0	0	0	74,539
375.70	2,332,164	3.31	0 59		5,449	0 59		16,308	21.440	1.359	22,799	1,364	805	0	2,525,712
375.80	6,508	2.00							28	0	28	0	0	0	6,783
376 00	194,534,832	2.05	0.15		1,109,526	0 14		1,295,637	2,383,963	107,970	2,491,933	1,744,417	244.218	0	201,217,029
378 00	10,020,157	3.24	0.39		120,627	0.44		124,281	125 595	10,357	135,952	31,281	13,764	0	10,972,150
379 10	93,180	3 17			18			18	373	2	374	0	0	0	96,923
380.00	111,536,567	2 84	0.60		3,154,138	0 54		2,710,597	1,130,265	225,883	1,356,148	379,449	204,902	0	119.785,169
381.00	15,673,710	2.45		0 01	(6,464)		0.02	(6,534)	76,093	(545)	75,548	12,460	0	249	16,317.047
381 10	8,582,181	7 36							148,004	0	148,004	908	0	0	10,018,285
382 00	11,909,425	1.94							60,340	0	60,340	12.227	0	0	12,404,117
383 00	3.567,106	2.59							25,520	0	25,520	5,711	0	0	3,771,086
384.00	2,972,034	1.73							5.572	0	5,572	0	0	0	3,027,751
385.00	2,981,725	3 78	0.20		40,219	0.21		34,434	20,549	2,870	23,419	1,402	294	0	3,200,248
387 00	75,343	2.83			5,397				316	0	316	0	0	0	78,949
387 40	839,236	4 94			530			488	17,843	41	17,884	0	0	0	1,018,077
387.50	363,074	11.76							38,254	0	38,254	0	0	0	689,017
390.10	85,422	2.10							210	0	210	0	0	0	87,523
391 10	1,791,600	4 10							12,023	0	12.023	0	0	0	1,651,332
391 11	13,746	4 56							93	0	93	0	0	0	14,674
391 12	2,520,633	8.93							11,298	0	11,298	0	0	0	741,895
392.00	53,268	13.50			(10,337)			(8,896)	1,097	(741)	356	0	0	0	56,707
393.00	16,675	0 00							0	0	0	0	0	0	14,375
394 00	5,797,220	3.73							46,196	0	46,196	0	0	0	6,086,766
394.12	1,953,286	0.01							16	0	16	0	0	0	1,953,449
395.00	35,023	3 55							109	0	109	0	0	0	22,184
396.00	1,367,642	1.49			(29,680)			(20,934)	1,782	(1,745)	38	0	0	0	1,367,292
397.10	163,625	0.00							0	0	0	0	0	0	0
397.50	884,202	11 10			5,881			5,881	26,713	490	27.203	0	0	0	1,113,070
398.00	199,269	6.71							4,818	0	4,818	0	0	0	207,959
303 00	8,753,916								254,588	0	254.588	161,191	0	0	9,067,322
305 00	0								0	0	0	0	0	0	0
362 00	0								0	0	0	0	0	0	0
362.10	(1,686,454)				115,460			373,852	0	31,154	31,154	0	0	0	(1,396,443)
374 20	179,478				(30.727)			(30,727)	0	(2,561)	(2.561)	0	0	0	153,872
375.71	740,882								29,015	0	29.015	1,329	0	0	997,239
389.20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,482,790	376,566	4,859,355	2,357,943	466,470	249	414,703,954

RESERVE BRINGFORWARD

umber of months for accrual calculation = 12 | umber of months in FFTY = 13

	2016	Accrual	PROJECTED 16			PROJECTED 2017			2017						
	NOV 30	Rates	COR	Salvage	5-yr Amort of NS	COR	Salvage	'5-yr Amort of NS	OCTOBER						
Account	Begin. Balance	2016	% of Rets	% of Rets	2011-2015	% of Rets	% of Rets	2012-2016	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,931	0 00							0	0	0	0	0	0	1,931
351 20	1.087,831	7 86			122			122	20,900	10	20.910	0	0	0	1,297,846
352 01	799,118	0 00							0	0	0	0	0	0	799,118
352.02	168 680	0.00							0	0	0	0	0	0	168 680
352.10	206,932	0 00							0	0	0	0	0	0	206,932
353.00	405,288	0.00							0	0	0	0	0	0	405.288
354.00	651,798	3.37							2,675	0	2.675	582	0	0	675.615
355 00	123,010	0 00							0	0	0	0	0	0	123,010
374.40	657,837	1 74	0.13		1.626	0.13		2,205	4,014	184	4,197	2,849	370	0	680,602
374 50	1,601.503	1 31							3,537	0	3,537	0	0	0	1,640,405
375.34	1.327,973	2.12	0 65		19,666	0.61		21,838	9.609	1,820	11,429	4,609	2,811	0	1,393,956
375 60	73,641	0 98			218			218	72	18	90	0	0	0	74,628
375 70	2,332,164	3.31	0 59		5,449	0 59		16,308	21.478	1,359	22.837	1,364	805	0	2.546,380
375.80	6,508	2.00							28	0	28	0	0	0	6,811
376 00	194,534,832	2.05	0.15		1,109,526	0.14		1,295,637	2,416.265	107,970	2,524,235	1,950,106	273,015	0	201,518,143
378.00	10,020,157	3.24	0.39		120,627	0.44		124,281	126.549	10,357	136,905	37,735	16,603	0	11,054,717
379 10	93,180	3 17			18			18	373	2	374	0	0	0	97,297
380 00	111,536,567	2.84	0 60		3,154,138	0 54		2,710.597	1,140,469	225,883	1,366 352	463.018	250,030	0	120,438,473
381 00	15,673,710	2.45		0.01	(6,464)		0.02	(6,534)	76,386	(545)	75,842	15,587	0	312	16,377,613
381 10	8,582,181	7.36							148,061	0	148,061	908	0	0	10,165,438
382.00	11,909,425	1 84							60,570	0	60,570	15,549	0	0	12,449,138
383.00	3,567,106	2 59							25,665	0	25,665	7,458	0	0	3,789,293
384 00	2,972,034	1 73							5 572	0	5 572	0	0	0	3,033,323
385 00	2,981,725	3 78	0.20		40,219	0.21		34,434	20,600	2,870	23,470	1.735	364	0	3,221,618
387.00	75,343	2.83			5,397				316	0	316	0	0	0	79,265
387.40	839,236	4 94			530			488	17,843	41	17,884	0	0	0	1,035,960
387.50	363,074	11 76							39,529	0	39,529	0	0	0	728,546
390 10	85,422	2.10							210	0	210	0	0	0	87,733
391.10	1,791,600	4.10							12,023	0	12,023	0	0	0	1,663,355
391 11	13,746	4 56							93	0	93	0	0	0	14,767
391 12	2,520,633	8 93							11,298	0	11,298	0	0	0	753,193
392 00	53,268	13.50			(10,337)			(8,896)	1,097	(741)	356	0	0	0	57,063
393.00	16,675	0 00							0	0	0	0	0	0	14,375
394 00	5,797,220	3 73							46,522	0	46,522	0	0	0	6,133,287
394.12	1,953,286	0 01							16	0	16	0	0	0	1,953,465
395 00	35,023	3 55							109	0	109	0	0	0	22,293
396 00	1,367,642	1.49			(29,680)			(20,934)	1,782	(1,745)	38	0	0	0	1,367,330
397.10	163,625	0 00							0	0	0	0	0	0	0
397.50	884,202	11.10			5.881			5,881	27,684	490	28,174	0	0	0	1,141,244
398 00	199,269	6 71							4,841	0	4,841	0	0	0	212,800
303.00	8,753,916								254,588	0	254,588	31.257	0	0	9,290,652
305 00	0								0	0	0	0	0	0	0
362.00	0								0	0	0	0	0	0	0
362.10	(1,686,454)				115,460			373,852	0	31,154	31,154	0	0	0	(1,365,289)
374.20	179,478				(30,727)			(30,727)	0	(2,561)	(2,561)	0	0	0	151,312
375 71	740,882								29,015	0	29,015	1,329	0	0	1.024,925
389 20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,529,787	376,566	4,906,352	2,534,086	543,999	312	416,532,534

RESERVE BRINGFORWARD

ımber of months for accrual calculation = 12 ımber of months in FFTY = 13

Account	2016 NOV 30 Begin. Balance	Accrual Rates 2016	PROJECTED 16 COR % of Rets	PROJECTED 16 Salvage % of Rets	5-yr Amort of NS 2011-2015	PROJECTED 2017 COR % of Rets	PROJECTED 2017 Salvage % of Rets	'5-yr Amort of NS 2012-2016	2017 NOVEMBER Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350 20	1,931	0.00							0	0	0	0	0	0	1,931
351.20	1,067,831	7.86			122			122	20,900	10	20,910	0	0	0	1.318,757
352 01	799,118	0 00							0	0	0	0	0	0	799,118
352.02	168,680	0.00							0	0	0	0	0	0	168,680
352.10	206,932	0.00							0	0	0	0	0	0	206,932
353 00	405,288	0.00							0	0	0	0	0	0	405,288
354 00	651,798	3.37							2,689	0	2,689	454	0	0	677,850
355.00	123,010	0 00							0	0	0	0	0	0	123,010
374 40	657,837	1.74	0 13		1,626	0.13		2.205	4 056	184	4,240	2,939	382	0	681,521
374 50	1,601,503	1.31							3,537	0	3,537	0	0	0	1,643,942
375.34	1,327,973	2.12	0.65		19,666	0.61		21,838	9.688	1,820	11,508	4,167	2,542	0	1,398.755
375 60	73,641	0 98			218			218	72	18	90	0	0	0	74,718
375 70	2,332,164	3.31	0 59		5,449	0 59		16,308	21,517	1,359	22.876	1.364	805	0	2,567.087
375.80	6,508	2.00							28	0	28	0	0	0	6,838
376 00	194,534,832	2.05	0.15		1,109,526	0.14		1,295,637	2,446,777	107,970	2,554,747	1,539,641	215,550	0	202,317,699
378.00	10,020,157	3 24	0 39		120.627	0.44		124,281	127.496	10,357	137,853	30,852	13.575	0	11,148,144
379 10	93,180	3.17			18			18	373	2	374	0	0	0	97,671
380 00	111,536,567	2 84	0 60		3,154,138	0.54		2,710,597	1,150,776	225,883	1,376,660	387,944	209,490	0	121,217,699
381 00	15,673,710	2.45		0.01	(6,464)		0 02	(6,534)	76 692	(545)	76,148	13,731	0	275	16,440,305
381.10	8.582,181	7.36							148,517	0	148,517	13,617	0	0	10,300 337
382 00	11,909,425	1.94							60,816	0	60,816	14.132	0	0	12,495,822
383.00	3,567,106	2.59							25,826	0	25,826	7,106	0	0	3,808,013
384.00	2,972,034	1 73							5 572	0	5,572	0	0	0	3,038,895
385.00	2,981.725	3.78	0.20		40,219	0.21		34,434	20,652	2,870	23 522	1,496	314	0	3,243,330
387.00	75,343	2.83			5,397				316	0	316	0	0	0	79,581
387.40	839,236	4.94			530			488	17,843	41	17,884	0	0	0	1,053,844
387 50	363,074	11 76							40,804	0	40,804	0	0	0	769,350
390.10	85,422	2.10							210	0	210	0	0	0	87,943
391.10	1,791,600	4.10							12,023	0	12,023	0	0	0	1,675,378
391.11	13,746	4 56							93	0	93	0	0	0	14,860
391 12	2,520.633	8.93							11,298	0	11,298	0	0	0	764,491
392.00	53,268	13 50			(10,337)			(8,896)	1,097	(741)	356	0	0	0	57,419
393 00	16,675	0.00							0	0	0	0	0	0	14,375
394 00	5,797,220	3.73							46,848	0	46,848	0	0	0	6,180,136
394 12	1,953,286	0.01							16	0	16	0	0	0	1,953.482
395.00	35,023	3.55							109	0	109	0	0	0	22,401
396.00	1,367,642	1 49			(29,680)			(20,934)	1,782	(1,745)	38	0	0	0	1,367,368
397.10	163,625	0 00							0	0	0	0	0	0	0
397 50	884.202	11.10			5,881			5,881	28,655	490	29.145	0	0	0	1,170,389
398 00	199,269	6 71							4,864	0	4,864	0	0	0	217,664
303 00	8,753 916								254,588	0	254,588	0	0	0	9,545,240
305 00	0								0	0	0	0	0	0	0
362.00	0								0	0	0	0	0	0	0
362 10	(1,686,454)				115,460			373,852	0	31,154	31,154	0	0	0	(1,334,135)
374.20	179,478				(30,727)			(30,727)	0	(2,561)	(2,561)	0	0	0	148,751
375 71	740,882								29,015	0	29,015	1,329	0	0	1,052,610
389.20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,575,546	376,566	4,952,112	2,018,772	442,657	275	419,023,491

RESERVE BRINGFORWARD

ımber of months for accrual calculation = 12 ımber of months in FFTY = 13

PROJECTED 16 PROJECTED 2017

	2016	Accrual			5-yr			'5-yr	2017						
	NOV 30	Rates	COR	Salvage	Amort of NS	COR	Salvage	Amort of NS	DECEMBER						
Account	Begin. Balance	2016	% of Rets	% of Rets	2011-2015	% of Rets	% of Rets	2012-2016	Avg. Accruals	Amort. of NS	Accruals	Retirements	Cost of Removal	Salvage	Ending Balance
350.20	1,931	0 00							0	0	0	0	0	0	1,931
351.20	1,067,831	7.86			122			122	20,900	10	20,910	0	0	0	1,339,667
352.01	799,118	0 00							0	0	0	0	0	0	799,118
352.02	168,680	0.00							0	0	0	0	0	0	168,680
352.10	206,932	0 00							0	0	0	0	0	0	206,932
353.00	405,288	0 00							0	0	0	0	0	0	405,288
354.00	651,798	3 37							2,699	0	2,699	224	0	0	680,325
355 00	123,010	0 00							0	0	0	0	0	0	123,010
374.40	657,837	1 74	0 13		1,626	0.13		2,205	4,093	184	4,277	1,957	254	0	683,587
374.50	1,601,503	1 31							3,537	0	3,537	0	0	0	1,647,478
375 34	1,327,973	2.12	0.65		19,666	0 61		21,838	9,748	1,820	11,568	2,461	1,501	0	1,406,360
375.60	73,641	0.98			218			218	72	18	90	0	0	0	74,808
375 70	2,332,164	3.31	0.59		5,449	0.59		16 308	21,555	1,359	22,914	1,364	805	0	2,587,833
375.80	6,508	2.00							28	0	28	0	0	0	6,866
376.00	194,534,832	2.05	0.15		1,109,526	0.14		1,295,637	2,467,087	107,970	2,575,057	783.300	109,662	0	203,999,794
378.00	10,020.157	3.24	0 39		120,627	0.44		124,281	128,147	10,357	138 504	16,229	7,141	0	11,263,278
379.10	93,180	3.17			18			18	373	2	374	0	0	0	98,046
380 00	111,536,567	2.84	0 60		3,154,138	0.54		2,710,597	1,158,024	225,883	1,383,907	210,384	113,607	0	122,277,614
381.00	15,673,710	2.45		0.01	(6,464)		0 02	(6,534)	76,918	(545)	76,374	7,887	0	158	16,508,949
381 10	8,582,181	7.36							148,959	0	148,959	454	0	0	10.448 842
382.00	11,909,425	1 94							61,002	0	61,002	8,390	0	0	12,548,434
383.00	3,567,106	2 59							25,953	0	25,953	4,418	0	0	3,829,549
384 00	2,972,034	1 73							5 572	0	5,572	0	0	0	3,044,466
385 00	2,981,725	3 78	0.20		40,219	0 21		34,434	20,690	2,870	23,559	839	176	0	3,265,874
387.00	75,343	2 83			5,397				316	0	316	0	0	0	79,896
387 40	839,236	4.94			530			488	17,843	41	17,884	0	0	0	1,071,728
387.50	363,074	11 76							42,001	0	42,001	0	0	0	811,351
390.10	85,422	2.10							210	0	210	0	0	0	88,154
391.10	1,791,600	4.10							11,220	0	11,220	470,390	0	0	1,216,208
391.11	13,746	4.56							93	0	93	0	0	0	14,953
391.12	2,520,633	8 93							11,298	0	11,298	0	0	0	775,789
392.00	53,268	13 50			(10,337)			(8,896)	1,068	(741)	327	5,209	0	0	52,537
393.00	16,675	0 00							0	0	0	939	0	0	13,436
394 00	5,797,220	3.73							46,864	0	46.864	186,714	0	0	6,040,286
394.12	1,953,286	0.01							16	0	16	0	0	0	1,953,498
395.00	35,023	3 55							96	0	96	8,812	0	0	13,685
396 00	1,367,642	1.49			(29,680)			(20,934)	1,782	(1,745)	38	0	0	0	1,367,406
397.10	163,625	0 00							0	0	0	0	0	0	0
397.50	884,202	11 10			5,881			5,881	29,567	490	30,057	0	0	0	1,200,446
398.00	199,269	6 71							4,862	0	4,862	9.172	0	0	213,354
303.00	8,753,916								254,588	0	254,588	0	0	0	9.799,828
305 00	0								0	0	0	0	0	0	0
362.00	0								0	0	0	0	0	0	0
362.10	(1,686,454)				115,460			373,852	0	31,154	31,154	0	963,491	0	(2.266,471)
374.20	179,478				(30,727)			(30,727)	0	(2,561)	(2,561)	0	0	0	146,190
375 71	740,882								29,015	0	29,015	1,329	0	0	1,080,296
389.20	0								0	0	0	0	0	0	0
Total	395,442,217				4,501,669			4,518,788	4,606,194	376,566	4,982,760	1,720,472	1,196,638	158	421,089,298

COLUMBIA STATEMENT NO. 6

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2016-2529660
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
NICOLE M.PALONEY
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

I. Introduction

Q. Please state your name and business address.

A. Nicole Paloney, 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 Director of Rates and Regulatory Affairs.

Q. What are your responsibilities as Director of Rates and Regulatory Affairs?

A. I am responsible for developing and directing rate activity on behalf of the Company before the Pennsylvania Public Utility Commission ("Commission") as well as coordinating and representing the Company's position in a variety of regulatory matters and proceedings.

Q. What is your educational and professional background?

A. I have a Bachelor of Science in Business and Administration with an emphasis in Accounting and Finance from The Ohio State University. In 1998, I was hired as a staff auditor for Deloitte, primarily serving middle market clients in a variety of industries, including manufacturing, public pension systems and not for profit clients. I was promoted to manager in 2004, and served in that capacity until I left Deloitte in July 2005. From August 2005 until August 2008, I was employed by Cardinal Health in Dublin, Ohio. Cardinal Health provides pharmaceutical and medical products to the Health Care industry, and is also a manufacturer of medical and surgical products. I was a manager in Internal Audit during my tenure at Cardinal, with responsibility over internal audits that took place in the manufacturing and corporate segments of the company.

In August 2008, I joined NiSource Corporate Services Company ("NCSC") as an Internal Audit manager, with responsibility for internal audits that took place in NiSource Inc.'s ("NiSource") Gas Distribution segment. In September 2011, I transitioned to the Regulatory Strategy and Support group in the role of Project Manager, providing support to the state regulatory teams in Pennsylvania and Maryland. In May 2014, I began my role as Director of Rates and Regulatory Affairs for the Company.

Q. Have you previously testified before this Commission or any other Commission?

A. Yes, I submitted testimony for Columbia in its 2015 base rate case at Docket No. R-2015-2468056 as the Rate Base witness. I also have submitted testimony in support of Columbia's request to lift the cap on its distribution system improvement charge at Docket No. P-2015-2521993 and Columbia's pending abandonment proceeding at Docket No. A-2015-2513395. In addition, I have testified before the Maryland Public Service Commission ("PSC") on behalf of Columbia Gas of Maryland as a cost of service witness in Case No. 9316 and a policy witness in Case No. 9354.

Q. What test year will you be addressing in your testimony?

A. I will be addressing the twelve month period ending November 30, 2015 as the

Historic Test Year, the twelve month period ended November 30, 2016 as the Future Test Year and the twelve month period ended December 31, 2017 as the Fully Forecasted Rate Year.

Q. Please describe the scope of your testimony in this proceeding.

A. First, I am supporting the exhibits listed and described in the following table:

Exhibit No.	Description
Exhibit No. 8	Historic test year rate base
Exhibit No. 10, Schedule 3(22)	Supporting data detailing curtailment adjustments, procedures and policies.
Exhibit No. 10, Schedule 4 (38) (39)	Company policy with respect to replacing customers lost through attrition and procedures to govern relationships between respondent and potential customers
Exhibit No. 10, Schedule 5(4)	Schedule showing maximum coincident peak day demand, maximum coincident three-day peak day demand, average winter season (Nov.-Mar.) monthly consumption, average summer season (Apr.- Oct.) monthly consumption and average daily consumption for each 12 month period for test year and four prior years by customer classification.
Exhibit No. 10, Schedule 7	Sales by customer class, sources of gas supply and line losses
Exhibit No. 12, Schedule 1 (5)	Schedule showing the sources of gas supply associated with annualized Dth sales
Exhibit No. 12. Schedule 2	Net fuel clause adjustment by month for the test year
Exhibit No. 12, Schedule 3	Statement of over/under collection from gas cost rate
Exhibit No. 12, Schedule 4(24)	Purchased gas for test year and prior year
Exhibit No. 12, Schedule 4(25)	Energy cost per Dth and operating ratio
Exhibit No. 12, Schedule 4(26)	Bulk transmission service costs
Exhibit No. 12, Schedule 4(30)	Purchased gas detail
Exhibit No. 12, Schedule 4(36)	Amounts of gas obtained through various suppliers

Exhibit No. 12, Schedule 5 (31)	Determination of fuel costs
Exhibit No. 12 Schedule 6 (11)	Net fuel clause adjustment
Exhibit No. 12, Schedule 7	Adjustment of purchased gas expense
Exhibit No. 12, Schedule 8	Statement of over/under collection from gas cost rate and recovery of fuel costs by the utility
Exhibit No. 13, Schedule 4(46)	Internal and independent audit reports of the test year and prior calendar year
Exhibit No. 13, Schedule 6(27)	Schedule of gas producing units retired or scheduled for retirement
Exhibit No. 15	Corporate history; overall system map; map of gas system facilities and gas service areas; and affiliate relationships
Exhibit No. 16 (7)	Recovery of uncollectible and delinquent accounts
Exhibit No. 17, Page 1(1)	Description of all property; gas supply; service agreements
Exhibit No. 17, Page 7(28)	Details of firm gas--affiliated and non-affiliated utilities
Exhibit No. 108	Future test year and fully forecasted test year rate base
Exhibit No. 110, Schedule 3(22)	Supporting data detailing curtailment adjustments, procedures and policies
Exhibit No. 110, Schedule 4	Company policy with respect to replacing customers lost through attrition and procedures to govern relationships between respondent and potential customers
Exhibit No. 110, Schedule 5(4)	Schedule showing maximum coincident peak day demand, maximum coincident three-day peak day demand, average winter season (Nov.-Mar.) monthly consumption, average summer season (Apr.- Oct.) monthly consumption and average daily consumption for each 12 month period for test year and four prior years by customer classification
Exhibit No. 110, Schedule 7	Sales by customer class, sources of gas supply and line losses
Exhibit No. 112, Schedule 1(5)	Schedule showing the sources of gas supply associated with annualized Dth sales
Exhibit No. 112, Schedule 2(18)	Fuel Adjustment Clause
Exhibit No. 112, Schedule 2(23)	Fuel cost in excess of base compared to fuel

	cost recovery
Exhibit No. 112, Schedule 2(24)	Purchased gas for test year and prior year
Exhibit No. 112, Schedule 2(25)	Energy cost and operating ratio used to determine increase in costs to serve additional load
Exhibit No. 112, Schedule 2(26)	Bulk transmission service costs
Exhibit No. 112, Schedule 2(30)	Purchased gas detail
Exhibit No. 112, Schedule 2(31)	Fuel costs included in the base cost of fuel
Exhibit No. 112, Schedule 2(36)	Amounts of gas obtained through various suppliers
Exhibit No. 112, Schedule 2(11)	Net fuel clause adjustment by month for the test year
Exhibit No. 112, Schedule 3	Adjustment of purchased gas expense
Exhibit No. 112, Schedule 4	Statement of over/under collection from gas cost rate and recovery of fuel costs by the utility
Exhibit No. 113, Schedule 3 (19), (39), (40), (41), (44), (45) and (46)	Internal and independent audit reports of the test year and prior calendar year
Exhibit No. 113, Schedule 4 (27)	Schedule of gas producing units retired or scheduled for retirement
Exhibit No. 115	Corporate history; overall system map; and affiliate relationships
Exhibit No. 116(7)	Recovery of uncollectibles and delinquent accounts
Exhibit No. 117, Page 1(1)	Description of all property; gas supply; service agreements
Exhibit No. 117, Page 1(28)	Details of firm gas--affiliated and non-affiliated utilities

Q. What matters will you address in your testimony?

A. I will present a schedule that demonstrates Columbia's rate base as of December 31, 2017. I will also describe the Company's rate base reflected in the revenue requirement presented in this proceeding.

I. Rate Base

Q. Is the forward looking rate year utilized by Columbia in this case similar to that used in its prior base rate case?

A. Yes. Columbia elected to use the Fully Forecasted Rate Year specifically provided for in Act 11 of 2012 in Docket Nos. R-2012-2321748, R-2014-2406274, and R-2015-2468056. The Company has made the same election in the current case.

Q. Are there any requirements in subsequent cases arising from the use of a Fully Forecasted Rate Year?

A. Yes. There are requirements from Docket No. R-2014-2406274 and Docket No. R-2015-2468056.

Pursuant to paragraph 25 of the approved settlement in Docket No. R-2014-2406274, Columbia is required to update Exhibit 108, Schedule 1 filed in proceeding R-2014-2406274 for the 12 months ending December 31, 2015 on or before April 1, 2016. See Exhibit NMP-1. Also pursuant to Paragraph 25 of the approved settlement in Docket No. R-2014-2406274, Columbia is required to provide a comparison of actual expenses and rate base additions for the 12 months ended December 31, 2015 to the projections in the case. See Exhibit NMP-2 for this comparison. Projected total Gas Plant in Service as of December 31, 2015 from R-2014-2406274 was $1,741,989,119, compared to actual plant in service of $1,769,530,815.

Pursuant to paragraph 53 of the approved settlement in Docket No. R-2015-

2468056, Columbia is required to provide the Commission and other parties, on or before April 1, 2016, an update of Columbia Exhibit 108, Schedule 1, which will include actual capital expenditures, plant additions and retirements by month for the twelve months ending December 31, 2015. See Exhibit NMP-1.

Q. Please explain the development of rate base at November 30, 2015 for the Historic Test Year, November 30, 2016 for the Future Test Year and December 31, 2017 for the Fully Forecasted Rate Year.

A. Rate base is summarized on Exhibit 8, page 3, and further detailed by the various components in Exhibit 8, Schedules 1-10, for the Historic Test Year. Rate base for the Future Test Year and the Fully Forecasted Rate Year are summarized on Exhibit 108, Page 3 and further detailed by the various components in Exhibit 108, Schedules 1-10. The Company's Fully Forecasted Rate Year rate base claim is $1,494,091,075.

Q. Please discuss the amounts included in Property, Plant and Equipment for the Historic Test Year as illustrated on Exhibit 8, Page 3.

A. The Company's Plant in Service includes plant in service per books as of November 30, 2015 in account 101 and 106. The Company will not be making a claim for Construction Work In Progress ("CWIP") as of the end of the Historic Test Year.

The Historic Test Year also includes per books Gas Stored Underground – Non-Current, Account 117 on Exhibit 8, Page 3, Line 5. Reductions are included for the reserve for depreciation, as provided for by Company witness Spanos (Columbia

Statement No. 5), and for gas lost in underground storage on lines 6 and 7, respectively.

Q. Please explain how the Company's Future Test Year and Fully Forecasted Rate Year Property, Plant and Equipment were developed.

A. The Company's Plant in Service as of December 31, 2017 as shown on Exhibit 108, Schedule 1, Column 5 was developed beginning from Column 2 of Page 1 with Gas Plant in Service at November 30, 2015 as also shown on Exhibit 8, Schedule 1 ($1,737,502,307). Forecasted capital expenditures from December 2015 through December 2017 per the Company's forecasted budget are shown in Exhibit 108, Schedule 1. Company witness Soyster (Columbia Statement No. 7) provides forecasted plant additions. Forecasted retirements from December 2015 to December 2017, supported by Company witness Spanos (Columbia Statement No. 5) are shown in Exhibit 108, Schedule 1. By adding forecasted capital expenditures and subtracting forecasted retirements, Exhibit 108, Schedule 1 reflects the net forecasted plant in service included in rate base as of December 31, 2017.

Q. Please explain the purpose of Page 2 of Exhibit 8.

A. This page satisfies 52 Pennsylvania Code Section 53.53 I.A, item 2 of the Commission's standard filing requirements, at Exhibit 8, Page 4, that the Company show its rate base claim from its last base rate proceeding.

Q. Have there been any changes in the Contribution in Aid of Construction amounts shown on Exhibit 8, Schedule 1 from the amount reported in the last base rate case as of test year ended November 30, 2015?

A. One change has been noted from the prior case on Exhibit 8, Schedule 1, line 30. Two charges totaling $7,229 were inadvertently closed to account 101-2000, when they should have been closed to the 101-1000 account. The Company is in the process of correcting this. Prior to November 2003, the Company recorded plant additions paid through Contribution in Aid of Construction in plant in service (101-1000), with a deduction reflected in contra accounts 101-2000, 101-3000 or 101-4000. Since November 2003, the Company has netted contributions against Plant in Service Account 101-1000, thus, no additional deduction is necessary.

Prior to January 2000, there was no 101-Gas Plant in Service offset for Customer Advances. As such, rate base would not be reduced through Account 101 for Customer Advances prior to January 2000. The reduction to rate base for these Customer Advances is made by including account 252 along with the Deferred Debit in account 186 to offset the post 1999 Customer Advances net in Plant in Service.

Q. Please explain Exhibit 8, Schedule 2.

A. This exhibit reflects the balance in construction work in progress ("CWIP"). The Company is not making a claim for CWIP in the Historic Test Year.

Q. Please explain Exhibit 108, Schedule 2.

A. Exhibit 108, Schedule 2 shows that forecasted CWIP, Account 107, is expected to remain at the same level for the Fully Forecasted Rate Year as it was at November 30, 2015

Q. Please explain the credits to Gas Plant in Service on Exhibit 8, Page 3, Lines 6 and 7 and Exhibit 108, Page 3, Lines 5 and 6.

A. Line 6, Depreciation Reserve, Accounts 108-111 in Exhibit 8, Page 3 for the Historic Test Year and Line 5 Exhibit 108 Page 3 for the Fully Forecasted Rate Year were detailed and supplied by Company witness Spanos, by plant account, in Exhibit 5 for the Historic Test Year and Exhibit 105 in the Fully Forecasted Rate Year. Exhibit 8, Page 3, Line 7, and Exhibit 108, Page 3 , Line 6 Accum. Provision Gas Lost – Underground Storage Account 117 is per books as of November 30, 2015 for the Historic Test Year and December 31, 2017 for the Fully Forecasted Rate Year.

Q. Did you include inventory balances in rate base?

A. Yes. As shown on Exhibit 8, Schedule 5, Materials and Supplies included in the historic rate base is a 13 month average of the historical monthly balances in Account 154, 186-99-12357 and 186-99-012980 materials holding clearing accounts. Materials and Supplies in the Fully Forecasted Rate Year rate base and shown on the Exhibit 108, Schedule 5 begins with November and December 2015 actual balances (most recent available), with January 2016 through November 2016 balances calculated by applying the GDP deflator supported by Company witness

Miller (Columbia Statement No. 4) in Exhibit 104, Schedule 2, Page 25 to the actual balances of January 2015 through November 2015.

Q. Did you include Prepayment balances in rate base?

A. Yes. Exhibit 8, Schedule 6 for the Historic Test Year and Exhibit 108, Schedule 6 for the Fully Forecasted Rate Year show prepayments for: Corporate Insurance, Account 16521000; Prepaid Insurance I/C, Account 1652000; Regulatory Commission Fees, Office of Consumer's Advocate ("OCA"), and Office of Small Business Advocate ("OSBA"), Account 16503600. The amount in the historic rate base is based on a 13 month average of the historic monthly balances per the Company's books. The amounts for the Fully Forecasted Rate Year rate base were determined by incrementally applying the GDP Deflators supported by Company witness Miller in Exhibit 104, Schedule 2 page 25 to the January 2015 through November 2015 actual balances to reflect expected new prepayments as of December 2017.

Q. Did you include Gas Stored Underground in rate base?

A. Yes, I did.

Q. What valuation methodology is applied to Gas Stored Underground?

A. As per the Commission's March 31, 2001 Order at Docket No. P-2010-2209925, Columbia uses the Weighted Average Cost of Gas ("WACOG") methodology to value Storage Gas.

Q. Please describe the WACOG accounting methodology you applied to value the Fully Forecasted Rate Year storage balance.

A. Under the WACOG accounting methodology, the actual cost and volume of the current month's injections are added to the inventory value calculated at the end of the previous month, and a new average cost per DTH is calculated for the current month. The current month's withdrawals are deducted from the balance at the new average cost per DTH. When storage gas is being injected (April – October), the inventory cost for the current month is added to the inventory cost from the previous month(s). At the end of injection season, the storage cost for the winter is well established. During the withdrawal season (November – March), withdrawals are made at the average price primarily resulting from injection season.

Q. Did you include an adjustment to Gas Stored Underground in rate base?

A. Yes. I have calculated a twelve month average cost of gas to be included in rate base.

Q. Do you provide exhibits supporting this storage adjustment?

A. Yes, I do.

Q. Please identify and explain those exhibits.

A. The supporting exhibits are Exhibit 8, Schedule 7 and Exhibit 108, Schedule 7. The actual December 2014 through November 2015 injections and withdrawals are reflected on Exhibit 8, Schedule 7 in columns A and E, respectively. A projected monthly average cost of gas is detailed in Column B. Therefore, under WACOG accounting methodology, the current month's injections (Column A) are multiplied by the Monthly Average Cost of Gas (Column B). The result is added to the inventory value calculated at the end of the previous month (Column G), and a new weighted average cost of gas per DTH is calculated (Column D) for the current month. The current month's withdrawals (Column E) are multiplied by the new weighted average cost of gas per DTH (Column D) and the result is deducted from the cumulative balance (Column G). This method is continued every month through November 2015. Line 15 calculates a twelve month average storage balance to be included in the Pro Forma Rate Base.

Exhibit 108, Schedule 7 repeats this process from November 2015 through December 2017. Injection rates are based on those included in the Company's 1307 (f) pre-filing data filed with the Commission on March 1, 2016. Lines 27 and 28 calculate a twelve month average storage balance for the Future Test Year rate base and Fully Forecasted Rate Year, rate base respectively.

Q. Did you include Deferred Income Taxes in rate base?

A. Yes, I did. Balances as of November 30, 2015 pertaining to Deferred Income Taxes included in rate base are shown on Exhibit 8, Schedule 8. The balances were supplied by Company witness Fischer (Columbia Statement No. 10) on Exhibit 7, Page 9. Forecasted balances as of November 30, 2016 and December 31, 2017 pertaining to Deferred Income Taxes included in rate base are shown on Exhibit

108, Schedule 8. These balances were supplied by Company witness Fischer on Exhibit 107, Pages 5 and 5a.

Q. How did you determine the Customer Deposits in rate base?

A. Customer Deposits, Account 235, is the 13 month historic average, as detailed on Exhibit 8, Schedule 9 for the Historic Test Year. The 13 month average for the forecasted rate base, detailed on Exhibit 108, Schedule 9, reflects projected balances for November 2015 through December 2017, with the entries for November and December of each year based on actual data for November and December of 2015. The balances for the months of January 2017 through October 2017 are the same as the balances in the months of January 2016 through October 2016 following the trend that deposits gradually go up in the winter and down in the summer. The balances for January 2016 – October 2017 are based on the historic test year balances.

Q. How did you determine the Customer Advances for Construction to be deducted from rate base?

A. The deduction to rate base for Customer Advances is made by including account 252, along with the Deferred Debit in Account 186 to offset the post 1999 Customer Advances net in Plant in Service. As discussed earlier in my testimony, the historic adjustment equals theper books balances at November 30, 2015 as detailed on Exhibit 8, Schedule 10. The future test year and fully forecasted test year adjustments equal the books balance at December 31, 2015, as detailed on Exhibit 108, Schedule 10.

Q. Does this complete your direct testimony?

A. Yes, it does.

Columbia Gas of Pennsylvania
Schedule 108 - Case R-2014 -2406274
Updated for Actuals Through December 31, 2015

Line No		Account No. (1)	Plant Beginning Balance 11/30/2014 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2014 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 1/31/2015 (8)=(5+6+7) $
			Gas Plant in Service						
1	**Intangible Plant**								
2	Organization Costs	301 00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302 10	26,489	0	0	26,489	0	0	26,489
4	Intangible Plant, General	303 00	1,320,595	0	0	1,320,595	0	0	1,320,595
5	Intangible Plant, Miscellaneous Software	303 30	16,993,538	120,856	0	17,114,395	56,535	(440,991)	16,729,939
6	**Underground Storage Plant**								
7	Land	350 10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350 20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351 20	3,413,834	(282,755)	0	3,131,079	0	0	3,131,079
10	Wells Construction	352 01	799,134	0	0	799,134	0	0	799,134
11	Wells Equipment	352 02	168,680	0	0	168,680	0	0	168,680
12	Storage Leasehold and Rights	352 10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352 12	67,498	0	0	67,498	0	0	67,498
14	Lines	353 00	405,288	0	0	405,288	0	0	405,288
15	Compressor Station Equipment	354 00	584,073	280,679	0	864,752	0	0	864,752
16	Measuring & Regulating Equipment	355 00	123,010	0	0	123,010	0	0	123,010
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374 10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374 20	479,275	0	0	479,275	0	0	479,275
20	Land Rights, City Gate/Main Line	374 30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374 40	2,128,782	0	(1,546)	2,127,237	0	(1,775)	2,125,462
22	Land Rights, City Other Distribution System, Loc	374 41	13	0	0	13	0	0	13
23	Rights of Way	374 50	3,233,107	0	0	3,233,107	0	0	3,233,107
24	Structures, City Gate Measurement & Regulating	375 20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375 31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375 40	3,347,923	46,650	(2,096)	3,392,478	4,176	0	3,396,653
27	Structures, Distribution Industrial M&R	375 60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375 70	5,060,838	769,881	0	5,830,720	11,482	0	5,842,202
29	Structures, Other Distribution System, Leased	375 71	1,125,911	0	0	1,125,911	0	0	1,125,911
30	Structures, Communication	375 80	16,515	0	0	16,515	0	0	16,515
31	Mains								
32	Mains	376 00	889,710,839	21,239,463	(2,159,023)	908,791,279	931,739	(133,861)	909,589,157
33	Mains - CSL Replacements	376 08	23,839,553	0	0	23,839,553	0	0	23,839,553
34	Bare Steel	376 30	70,618,980	0	(384,489)	70,234,491	0	(14,560)	70,219,931
35	Cast Iron	376 80	570,600	0	(6,151)	564,449	0	0	564,449
36	Measuring & Regulating Equipment General	378 10	56,453	0	0	56,453	0	0	56,453
37	Measuring & Regulating Equipment Regulating	378 20	29,250,421	1,527,163	(29,750)	30,747,835	(42,794)	(1,192)	30,703,848
38	Measuring & Regulating Equipment Local Gas	378 30	457,281	0	0	457,281	0	0	457,281
39	Measuring & Regulating Equipment City Gate	379 10	141,567	0	0	141,567	0	0	141,567
40	Measuring & Regulating Equipment Exchange Gas	379 11	(450)	0	0	(450)	0	0	(450)
41	Services	380 00	387,198,097	(11,171,298)	(352,261)	375,674,538	344,911	(244,450)	375,774,999
42	Meters	381 00	34,123,146	200,454	(29,918)	34,293,681	55,118	(33,458)	34,315,341
43	Auto Meter Reading Devices	381 10	22,928,475	97,733	0	23,026,208	0	0	23,026,208
44	Meter Installations	382 00	34,184,825	94,382	(4,715)	34,274,492	71,843	(5,421)	34,340,915
45	House Regulators	383 00	10,430,768	48,942	(441)	10,479,269	30,834	(688)	10,509,415
46	House Regulators Installations	384 00	3,864,772	0	0	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment Station Equipment	385 00	5,526,196	9,945	(6,252)	5,529,890	(5,402)	(2,075)	5,522,413
48	Industrial M&R Equipment Large Volume	385 10	1,189,991	0	(1,435)	1,188,556	0	(8,523)	1,180,033
49	Other Equipment	387 10	16,603	0	0	16,603	0	0	16,603
50	Other Equipment, Odorization	387 20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387 42	121,945	0	0	121,945	0	0	121,945
52	Other Equipment, Other Communications	387 44	656,004	175	0	656,179	0	(19,681)	636,499
53	Other Equipment, Telemetering	387 45	2,087,866	105,441	0	2,193,308	246,229	0	2,439,536
54	Other Equipment, Customer Information Service	387 46	259,436	0	0	259,436	0	0	259,436
55	**General Plant**								
56	Structures, Communications	390 10	49,821	0	0	49,821	0	0	49,821
57	Office Furniture & Equipment, Unspecified	391 10	2,944,321	0	0	2,944,321	0	0	2,944,321
58	Office Furniture & Equipment, Data handling Equip	391 11	49,805	0	0	49,805	0	0	49,805
59	Office Furniture & Equipment, Information Systems	391 12	2,197,893	195,007	0	2,392,901	0	0	2,392,901
60	Office Furniture & Equipment, Air Condition Equip	391 20	3,007	0	0	3,007	0	0	3,007
61	Transportation Equipment, Trailers > $1,000	392 20	110,152	0	(10,545)	99,607	0	(12,904)	86,703
62	Transportation Equipment, Trailers $1,000 or <	392 21	10,830	0	0	10,830	0	0	10,830
63	Stores Equipment	393 00	16,675	0	0	16,675	0	0	16,675
64	Tools, Garage & Service Equipment	394 10	122,964	0	0	122,964	0	0	122,964
65	Tools, CNG Equipment, Stationary	394 11	1,774,190	0	0	1,774,190	0	0	1,774,190
66	Tools, CNG Equipment, Portable	394 12	179,308	0	0	179,308	0	0	179,308
67	Tools, Shop Equipment	394 20	72,307	0	0	72,307	0	0	72,307
68	Tools, Tools and Other	394 30	12,181,053	65,715	0	12,246,768	13,853	0	12,260,621
69	Tools, High Pressure Stopping	394 31	10,847	0	0	10,847	0	0	10,847
70	Laboratory Equipment Gas	395 00	72,218	0	0	72,218	0	0	72,218
71	Power Operated Equipment	396 00	1,435,493	0	0	1,435,493	0	0	1,435,493
72	Communication Equipment	397 00	210,798	0	0	210,798	0	0	210,798
73	Communication Equipment, Telephone	397 10	342,306	0	0	342,306	0	0	342,306
74	Communication Equipment, Radio	397 20	2,339,889	0	0	2,339,889	0	0	2,339,889
75	Communication Equipment, Other	397 40	0	0	0	0	0	0	0
76	Communication Equipment, Telemetering	397 50	828,223	0	0	828,223	0	0	828,223
77	Miscellaneous Equipment	398 00	570,771	0	0	570,771	0	0	570,771
78	**Total Gas Plant in Service**		1,682,649,362	13,348,436	(2,988,622)	1,693,009,176	1,718,523	(919,579)	1,693,808,120

Line No.	Description	Account No. (1)	Plant Beginning Balance 1/31/2015 (2) $	Additions (3) $	Retirements (4) $	Balance as of 2/28/2015 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 3/31/2015 (8)=(5+6+7) $
			Gas Plant in Service						
1	**Intangible Plant**								
2	Organization Costs	301 00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302 10	26,489	0	0	26,489	0	0	26,489
4	Intangible Plant, General	303 00	1,320,595	0	0	1,320,595	0	0	1,320,595
5	Intangible Plant, Miscellaneous Software	303 30	16,729,939	33,410	0	16,763,349	202,872	0	16,966,220
6	**Underground Storage Plant**								
7	Land	350 10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350 20	1,932	0	0	1,932	0	0	1,932

9	Compressor Station Structures	351 20	3,131,079	0	0	3,131,079	0	0	3,131,079
10	Wells Construction	352 01	799,134	0	0	799,134	0	0	799,134
11	Wells Equipment	352 02	168,680	0	0	168,680	0	0	168,680
12	Storage Leasehold and Rights	352 10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352 12	67,498	0	0	67,498	0	0	67,498
14	Lines	353 00	405,288	0	0	405,288	0	0	405,288
15	Compressor Station Equipment	354 00	864,752	0	0	864,752	0	0	864,752
16	Measuring & Regulating Equipment	355 00	123,010	0	0	123,010	0	0	123,010
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374 10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374 20	479,275	0	0	479,275	0	0	479,275
20	Land Rights, City Gate/Main Line	374 30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374 40	2,125,462	0	0	2,125,462	24,878	0	2,150,341
22	Land Rights, City Other Distribution System, Loc	374 41	13	0	0	13	0	0	13
23	Rights of Way	374 50	3,233,107	0	0	3,233,107	0	0	3,233,107
24	Structures, City Gate Measurement & Regulating	375 20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375 31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375 40	3,396,653	43,185	(2,816)	3,437,023	42,082	(5,143)	3,473,961
27	Structures, Distribution Industrial M&R	375 60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375 70	5,842,202	15,249	0	5,857,450	0	0	5,857,450
29	Structures, Other Distribution System, Leased	375 71	1,125,911	0	0	1,125,911	0	0	1,125,911
30	Structures, Communication	375 80	16,515	0	0	16,515	0	0	16,515
31	Mains:								
32	Mains	376 00	909,589,157	2,339,855	(62,119)	911,866,894	2,398,541	(96,667)	914,168,767
33	Mains - CSL Replacements	376 08	23,839,553	0	0	23,839,553	0	0	23,839,553
34	Bare Steel	376 30	70,219,931	(14,656)	(40,676)	70,164,599	0	(54,939)	70,109,660
35	Cast Iron	376 80	564,449	0	(7)	564,442	0	(173)	564,269
36	Measuring & Regulating Equipment General	378 10	56,453	0	0	56,453	0	0	56,453
37	Measuring & Regulating Equipment Regulating	378 20	30,703,848	(83,996)	(8,785)	30,611,067	49,130	(10,008)	30,650,189
38	Measuring & Regulating Equipment Local Gas	378 30	457,281	0	0	457,281	0	0	457,281
39	Measuring & Regulating Equipment City Gate	379 10	141,567	0	0	141,567	0	0	141,567
40	Measuring & Regulating Equipment Exchange Gas	379 11	(450)	0	0	(450)	0	0	(450)
41	Services	380 00	375,774,999	1,983,441	(193,831)	377,564,610	2,111,828	(192,016)	379,484,422
42	Meters	381 00	34,315,341	147,608	(37,071)	34,425,878	68,042	(31,951)	34,461,969
43	Auto Meter Reading Devices	381 10	23,026,208	0	0	23,026,208	0	0	23,026,208
44	Meter Installations	382 00	34,340,915	56,862	(4,399)	34,393,377	64,540	(5,362)	34,452,555
45	House Regulators	383 00	10,509,415	35,108	(600)	10,543,923	30,926	(3,363)	10,571,486
46	House Regulators Installations	384 00	3,864,772	0	0	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment Station Equipment	385 00	5,522,413	4,198	325	5,526,936	2,082	(26,150)	5,502,868
48	Industrial M&R Equipment Large Volume	385 10	1,180,033	0	(1,156)	1,178,877	0	0	1,178,877
49	Other Equipment	387 10	16,603	0	0	16,603	0	0	16,603
50	Other Equipment, Odorization	387 20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387 42	121,945	0	0	121,945	0	0	121,945
52	Other Equipment, Other Communications	387 44	636,499	0	0	636,499	0	0	636,499
53	Other Equipment, Telemetering	387 45	2,439,536	36,022	0	2,475,558	89,575	0	2,565,133
54	Other Equipment, Customer Information Service	387 46	259,436	0	0	259,436	0	0	259,436
55	**General Plant**								
56	Structures, Communications	390 10	49,821	0	0	49,821	0	0	49,821
57	Office Furniture & Equipment, Unspecified	391 10	2,944,321	0	0	2,944,321	0	0	2,944,321
58	Office Furniture & Equipment, Data handling Equip	391 11	49,805	0	0	49,805	0	0	49,805
59	Office Furniture & Equipment, Information Systems	391 12	2,392,901	66,349	0	2,459,249	22,844	0	2,482,093
60	Office Furniture & Equipment, Air Condition Equip	391 20	3,007	0	0	3,007	0	0	3,007
61	Transportation Equipment, Trailers > $1,000	392 20	86,703	0	0	86,703	0	0	86,703
62	Transportation Equipment, Trailers $1,000 or <	392 21	10,830	0	0	10,830	0	0	10,830
63	Stores Equipment	393 00	16,675	0	0	16,675	0	0	16,675
64	Tools, Garage & Service Equipment	394 10	122,964	0	0	122,964	0	0	122,964
65	Tools, CNG Equipment, Stationary	394 11	1,774,190	0	0	1,774,190	0	0	1,774,190
66	Tools, CNG Equipment, Portable	394 12	179,308	0	0	179,308	0	0	179,308
67	Tools, Shop Equipment	394 20	72,307	0	0	72,307	0	0	72,307
68	Tools, Tools and Other	394 30	12,260,621	25,792	0	12,286,413	66,152	0	12,352,565
69	Tools, High Pressure Stopping	394 31	10,847	0	0	10,847	0	0	10,847
70	Laboratory Equipment Gas	395 00	72,218	0	0	72,218	0	0	72,218
71	Power Operated Equipment	396 00	1,435,493	0	0	1,435,493	0	0	1,435,493
72	Communication Equipment	397 00	210,798	0	0	210,798	0	0	210,798
73	Communication Equipment, Telephone	397 10	342,306	0	0	342,306	0	0	342,306
74	Communication Equipment, Radio	397 20	2,339,889	0	0	2,339,889	0	0	2,339,889
75	Communication Equipment, Other	397 40	0	0	0	0	0	0	0
76	Communication Equipment, Telemetering	397 50	828,223	0	0	828,223	0	0	828,223
77	Miscellaneous Equipment	398 00	570,771	0	0	570,771	0	0	570,771
78	**Total Gas Plant in Service**		1,693,808,120	4,688,425	(351,134)	1,698,145,411	5,173,492	(425,770)	1,602,893,133

Line No.	Description	Account No. (1)	Gas Plant in Service: Plant Beginning Balance 3/31/2015 (2) $	Additions (3) $	Retirements (4) $	Balance as of 4/30/2015 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 5/31/2015 (8)=(5+6+7) $
1	**Intangible Plant**								
2	Organization Costs	301 00	100,099	0	0	100,099	-	-	100,099
3	Franchises/Consent, Perpetual	302 10	26,489	0	0	26,489	-	-	26,489
4	Intangible Plant, General	303 00	1,320,595	0	0	1,320,595	-	-	1,320,595
5	Intangible Plant, Miscellaneous Software	303 30	16,966,220	42,524	(19,740)	16,989,004	9,281 33	-	16,998,285
6	**Underground Storage Plant**								
7	Land	350 10	23,882	0	0	23,882	-	-	23,882
8	Rights of Way	350 20	1,932	0	0	1,932	-	-	1,932
9	Compressor Station Structures	351 20	3,131,079	0	0	3,131,079	-	-	3,131,079
10	Wells Construction	352 01	799,134	0	0	799,134	-	-	799,134
11	Wells Equipment	352 02	168,680	0	0	168,680	-	-	168,680
12	Storage Leasehold and Rights	352 10	139,442	0	0	139,442	-	-	139,442
13	Other Leases	352 12	67,498	0	0	67,498	-	-	67,498
14	Lines	353 00	405,288	0	0	405,288	-	-	405,288
15	Compressor Station Equipment	354 00	864,752	0	0	864,752	-	-	864,752
16	Measuring & Regulating Equipment	355 00	123,010	0	0	123,010	-	-	123,010
							-	-	
17	**Distribution Plant**						-	-	
18	Land, City Gate/Main Line Industrial	374 10	21,944	0	0	21,944	-	-	21,944
19	Land, Other Distribution System	374 20	479,275	0	0	479,275	-	-	479,275
20	Land Rights, City Gate/Main Line	374 30	95,361	0	0	95,361		-	95,361
21	Land Rights, City Other Distribution System	374 40	2,150,341	0	0	2,150,341	122 34	-	2,150,463
22	Land Rights, City Other Distribution System, Loc	374 41	13	0	0	13	-	-	13
23	Rights of Way	374 50	3,233,107	0	0	3,233,107	-	-	3,233,107
24	Structures, City Gate Measurement & Regulating	375 20	7,026	0	0	7,026	-	-	7,026
25	Structures, General Meas & Reg Local Gas	375 31	4,012	0	0	4,012			4,012
26	Structures, Regulating	375 40	3,473,961	43,974	0	3,517,936	15,300 46	(7 57)	3,533,229
27	Structures, Distribution Industrial M&R	375 60	87,670	0	0	87,670		-	87,670
28	Structures, Other Distribution System	375 70	5,857,450	0	0	5,857,450	1,027,764 66	-	6,885,215

29	Structures, Other Distribution System, Leased	375 71	1,125,911	0	0	1,125,911	0	-	1,125,911
30	Structures, Communication	375 80	16,515	0	0	16,515	-		16,515
31	Mains								
32	Mains	376 00	914,168,767	2,651,842	(115,644)	916,704,966	14,976,181 45	(331,724 65)	931,349,422
33	Mains - CSL Replacements	376 08	23,839,553	0	(155)	23,839,398	-	-	23,839,398
34	Bare Steel	376 30	70,109,660	0	(46,742)	70,062,918	-	(53,277 33)	70,009,641
35	Cast Iron	376 80	564,269	0	0	564,269			564,269
36	Measuring & Regulating Equipment General	378 10	56,453	0	0	56,453	-	-	56,453
37	Measuring & Regulating Equipment Regulating	378 20	30,650,189	307,838	(116)	30,957,912	701,947 33	(38,265 14)	31,621,594
38	Measuring & Regulating Equipment Local Gas	378 30	457,281	0	0	457,281	-	-	457,281
39	Measuring & Regulating Equipment City Gate	379 10	141,567	0	0	141,567			141,567
40	Measuring & Regulating Equipment Exchange Gas	379 11	(450)	0	0	(450)			(450)
41	Services	380 00	379,484,422	2,983,433	(239,083)	382,228,772	5,757,616 06	(394,560 49)	387,591,828
42	Meters	381 00	34,461,969	79,850	(18,383)	34,523,436	48,429 49	(39,289 18)	34,532,576
43	Auto Meter Reading Devices	381 10	23,026,208	0	0	23,026,208	133,528 36	-	23,159,736
44	Meter Installations	382 00	34,452,555	94,055	(8,045)	34,538,565	95,652 90	(8,464 95)	34,625,753
45	House Regulators	383 00	10,571,486	28,302	(962)	10,598,827	28,415 51	(831 59)	10,626,411
46	House Regulators Installations	384 00	3,864,772	0	0	3,864,772	-	-	3,864,772
47	Industrial M&R Equipment Station Equipment	385 00	5,502,868	13,111	0	5,515,979	37,495 10	(1,710 07)	5,551,764
48	Industrial M&R Equipment Large Volume	385 10	1,178,877	0	(2,478)	1,176,399	-	(5,114 27)	1,171,285
49	Other Equipment	387 10	16,603	0	0	16,603	-	-	16,603
50	Other Equipment, Odorization	387 20	117,248	0	0	117,248	-	-	117,248
51	Other Equipment, Radio	387 42	121,945	0	0	121,945		-	121,945
52	Other Equipment, Other Communications	387 44	636,499	0	0	636,499	-	(999 64)	635,499
53	Other Equipment, Telemetering	387 45	2,565,133	145,255	0	2,710,388	807,241 83	-	3,517,630
54	Other Equipment, Customer Information Service	387 46	259,436	0	0	259,436	-	-	259,436
							-	-	
55	**General Plant**						-	-	
56	Structures, Communications	390 10	49,821	0	0	49,821		-	49,821
57	Office Furniture & Equipment, Unspecified	391 10	2,944,321	0	(1,097,548)	1,846,774	-	-	1,846,774
58	Office Furniture & Equipment, Data handling Equip	391 11	49,805	0	(25,378)	24,427	-	-	24,427
59	Office Furniture & Equipment, Information Systems	391 12	2,482,093	10,820	0	2,492,914	78,534 18	-	2,571,448
60	Office Furniture & Equipment, Air Condition Equip	391 20	3,007	0	0	3,007	-	-	3,007
61	Transportation Equipment, Trailers > $1,000	392 20	86,703	0	0	86,703	-	-	86,703
62	Transportation Equipment, Trailers $1,000 or <	392 21	10,830	0	0	10,830	-	-	10,830
63	Stores Equipment	393 00	16,675	0	0	16,675	-	-	16,675
64	Tools, Garage & Service Equipment	394 10	122,964	0	(21,504)	101,460	-	-	101,460
65	Tools, CNG Equipment, Stationary	394 11	1,774,190	0	0	1,774,190		-	1,774,190
66	Tools, CNG Equipment, Portable	394 12	179,308	0	0	179,308	-	-	179,308
67	Tools, Shop Equipment	394 20	72,307	0	(4,732)	67,575	-	-	67,575
68	Tools, Tools and Other	394 30	12,352,565	250,389	(531,166)	12,071,788	249,816 25	-	12,321,604
69	Tools, High Pressure Stopping	394 31	10,847	0	0	10,847	-	-	10,847
70	Laboratory Equipment Gas	395 00	72,218	0	(21,557)	50,661	-	-	50,661
71	Power Operated Equipment	396 00	1,435,493	0	0	1,435,493	-	-	1,435,493
72	Communication Equipment	397 00	210,798	0	0	210,798	-		210,798
73	Communication Equipment, Telephone	397 10	342,306	0	0	342,306	-	-	342,306
74	Communication Equipment, Radio	397 20	2,339,889	0	(1,142,626)	1,197,263	0	0	1,197,263
75	Communication Equipment, Other	397 40	0	0	0	0	0	0	0
76	Communication Equipment, Telemetering	397 50	828,223	0	0	828,223	0	(29,824 98)	798,398
77	Miscellaneous Equipment	398 00	570,771	0	(209,862)	360,909	0	0	360,909
78	**Total Gas Plant in Service**		1,602,893,133	6,651,393	(3,505,720)	1,606,038,806	23,967,327	(904,070)	1,629,102,063

Line No.	Description	Account No. (1)	Plant Beginning Balance 5/31/2015 (2) $	Additions (3) $	Retirements (4) $	Balance as of 6/30/2015 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 7/31/2015 (8)=(5+6+7) $
			Gas Plant in Service						
1	**Intangible Plant**								
2	Organization Costs	301.00	100,099	-	-	100,099	-	-	100,099
3	Franchises/Consent, Perpetual	302 10	26,489	-	-	26,489	-	-	26,489
4	Intangible Plant, General	303 00	1,320,595	-	-	1,320,595	-	-	1,320,595
5	Intangible Plant, Miscellaneous Software	303 30	16,998,285	273,873	-	17,272,158	133,306	-	17,405,465
				-	-		-	-	
6	**Underground Storage Plant**				-		-	-	
7	Land	350 10	23,882	-	-	23,882	-	-	23,882
8	Rights of Way	350 20	1,932	-	-	1,932	-	-	1,932
9	Compressor Station Structures	351 20	3,131,079	7,873	-	3,138,952	-	-	3,138,952
10	Wells Construction	352 01	799,134	-	-	799,134	-	-	799,134
11	Wells Equipment	352 02	168,680	-	-	168,680	-	-	168,680
12	Storage Leasehold and Rights	352 10	139,442	-	-	139,442	-	-	139,442
13	Other Leases	352 12	67,498	-	-	67,498	-	-	67,498
14	Lines	353 00	405,288	-	-	405,288	-	-	405,288
15	Compressor Station Equipment	354 00	864,752	-	-	864,752	-	-	864,752
16	Measuring & Regulating Equipment	355 00	123,010	-	-	123,010		-	123,010
				-	-				
17	**Distribution Plant**			-	-				
18	Land, City Gate/Main Line Industrial	374 10	21,944	-	-	21,944	-	-	21,944
19	Land, Other Distribution System	374 20	479,275	-	-	479,275	-	-	479,275
20	Land Rights, City Gate/Main Line	374 30	95,361		-	95,361	-	-	95,361
21	Land Rights, City Other Distribution System	374 40	2,150,463	6,156	-	2,156,619	24,454	-	2,181,073
22	Land Rights, City Other Distribution System, Loc	374 41	13	-	-	13		-	13
23	Rights of Way	374 50	3,233,107	-	-	3,233,107	-	-	3,233,107
24	Structures, City Gate Measurement & Regulating	375 20	7,026	-	-	7,026	-	-	7,026
25	Structures, General Meas & Reg Local Gas	375 31	4,012		-	4,012	-	-	4,012
26	Structures, Regulating	375 40	3,533,229	1,412	-	3,534,641	8,905	-	3,543,546
27	Structures, Distribution Industrial M&R	375 60	87,670		-	87,670			87,670
28	Structures, Other Distribution System	375 70	6,885,215	4,800	-	6,890,015			6,890,015
29	Structures, Other Distribution System, Leased	375 71	1,125,911	-	-	1,125,911			1,125,911
30	Structures, Communication	375 80	16,515			16,515			16,515
31	Mains								
32	Mains	376 00	931,349,422	12,273,103	(366,846)	943,255,678	9,602,101	(485,489)	952,372,290
33	Mains - CSL Replacements	376 08	23,839,398	-	-	23,839,398	-	-	23,839,398
34	Bare Steel	376 30	70,009,641	-	(104,065)	69,905,575	-	(100,354)	69,805,221
35	Cast Iron	376 80	564,269	-	(7,437)	556,832	-	(17,040)	539,792
36	Measuring & Regulating Equipment General	378 10	56,453	-	(115)	56,338	-	-	56,338
37	Measuring & Regulating Equipment Regulating	378 20	31,621,594	86,298	(74,443)	31,633,449	22,141	(3,042)	31,652,547
38	Measuring & Regulating Equipment Local Gas	378 30	457,281	-	6,451	463,732	-	-	463,732
39	Measuring & Regulating Equipment City Gate	379 10	141,567	-	-	141,567	-	-	141,567
40	Measuring & Regulating Equipment Exchange Gas	379 11	(450)	-	-	(450)	-	-	(450)
41	Services	380 00	387,591,828	4,236,535	(379,036)	391,449,326	3,713,559	(476,325)	394,686,560
42	Meters	381 00	34,532,576	137,891	(50,051)	34,620,417	106,366	(46,417)	34,680,366
43	Auto Meter Reading Devices	381 10	23,159,736	(20)	-	23,159,716	150,308	-	23,310,025
44	Meter Installations	382 00	34,625,753	136,441	(12,464)	34,749,730	26,526	(7,354)	34,768,902
45	House Regulators	383 00	10,626,411	35,124	(992)	10,660,543	34,129	(804)	10,693,867
46	House Regulators Installations	384 00	3,864,772	-	-	3,864,772	-	-	3,864,772
47	Industrial M&R Equipment Station Equipment	385 00	5,551,764	315	(8,874)	5,543,205	5,339	(2,546)	5,545,998
48	Industrial M&R Equipment Large Volume	385 10	1,171,285	-	(449)	1,170,836	-	(3,502)	1,167,334
49	Other Equipment	387 10	16,603	-	-	16,603	-	-	16,603

50	Other Equipment, Odorization	387 20	117,248	-	-	117,248	-	-	117,248
51	Other Equipment, Radio	387 42	121,945		-	121,945	-	-	121,945
52	Other Equipment, Other Communications	387 44	635,499	-	-	635,499	-	-	635,499
53	Other Equipment, Telemetering	387 45	3,517,630	68,364	-	3,585,994	56,180	-	3,642,174
54	Other Equipment, Customer Information Service	387 46	259,436	-	-	259,436	-	-	259,436
							-	-	
55	**General Plant**			-	-		-	-	
56	Structures, Communications	390 10	49,821	-	-	49,821	-	-	49,821
57	Office Furniture & Equipment, Unspecified	391 10	1,846,774	11,268	(2,146)	1,855,896	-	-	1,855,896
58	Office Furniture & Equipment, Data handling Equip	391 11	24,427	-	-	24,427	-	-	24,427
59	Office Furniture & Equipment, Information Systems	391 12	2,571,448	-	-	2,571,448	-	-	2,571,448
60	Office Furniture & Equipment, Air Condition Equip	391 20	3,007	-	-	3,007	-	-	3,007
61	Transportation Equipment, Trailers > $1,000	392 20	86,703	-		86,703			86,703
62	Transportation Equipment, Trailers $1,000 or <	392 21	10,830	-	-	10,830			10,830
63	Stores Equipment	393 00	16,675	-	-	16,675			16,675
64	Tools, Garage & Service Equipment	394 10	101,460	-	(1,345)	100,115			100,115
65	Tools, CNG Equipment, Stationary	394 11	1,774,190			1,774,190			1,774,190
66	Tools, CNG Equipment, Portable	394 12	179,308	-	-	179,308			179,308
67	Tools, Shop Equipment	394 20	67,575	-	(802)	66,773			66,773
68	Tools, Tools and Other	394 30	12,321,604	119,569	(53,791)	12,387,382	117,259	(34,032)	12,470,608
69	Tools, High Pressure Stopping	394 31	10,847	-	-	10,847	-	-	10,847
70	Laboratory Equipment Gas	395 00	50,661	-		50,661	-	-	50,661
71	Power Operated Equipment	396 00	1,435,493	-	-	1,435,493	-	-	1,435,493
72	Communication Equipment	397 00	210,798	-	-	210,798	-	-	210,798
73	Communication Equipment, Telephone	397 10	342,306	-	-	342,306	-		342,306
74	Communication Equipment, Radio	397 20	1,197,263	-	(231,496)	965,767	-	(2,666)	963,101
75	Communication Equipment, Other	397 40	0	-	-	0			0
76	Communication Equipment, Telemetering	397 50	798,398	-	-	798,398	0	0	798,398
77	Miscellaneous Equipment	398 00	360,909	-	-	360,909	7,249	(2,966)	365,192
78	**Total Gas Plant in Service**		1,629,102,063	17,399,000	(1,287,901)	1,645,213,162	14,007,823	(1,182,537)	1,658,038,447

Line No.	Description	Account No. (1)	Gas Plant in Service: Plant Beginning Balance 7/31/2015 (2) $	Additions (3) $	Retirements (4) $	Balance as of 8/31/2015 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 9/30/2015 (8)=(5+6+7) $	
1	**Intangible Plant**									
2	Organization Costs	301 00	100,099	-	-	100,099	-	-	100,099	
3	Franchises/Consent, Perpetual	302 10	26,489	-	-	26,489	-	-	26,489	
4	Intangible Plant, General	303 00	1,320,595	-	-	1,320,595	-	-	1,320,595	
5	Intangible Plant, Miscellaneous Software	303 30	17,405,465	122,026 51	-	17,527,491	77,776	-	17,605,267	
							-	-		
6	**Underground Storage Plant**						-	-		
7	Land	350 10	23,882	-	-	23,882	-	-	23,882	
8	Rights of Way	350 20	1,932	-	-	1,932	-	-	1,932	
9	Compressor Station Structures	351 20	3,138,952	-	-	3,138,952	-	-	3,138,952	
10	Wells Construction	352 01	799,134	-	-	799,134	-	-	799,134	
11	Wells Equipment	352 02	168,680	-	-	168,680	-	-	168,680	
12	Storage Leasehold and Rights	352 10	139,442	-	-	139,442	-	-	139,442	
13	Other Leases	352 12	67,498	-	-	67,498	-	-	67,498	
14	Lines	353 00	405,288	-	-	405,288	-	-	405,288	
15	Compressor Station Equipment	354 00	864,752	-	-	864,752	-	-	864,752	
16	Measuring & Regulating Equipment	355 00	123,010	-	-	123,010	-	-	123,010	
							-	-		
17	**Distribution Plant**						-	-		
18	Land, City Gate/Main Line Industrial	374 10	21,944	-	-	21,944	-	-	21,944	
19	Land, Other Distribution System	374 20	479,275	-	-	479,275	-	-	479,275	
20	Land Rights, City Gate/Main Line	374 30	95,361			95,361	-	-	95,361	
21	Land Rights, City Other Distribution System	374 40	2,181,073	60,026 63	(13,669 50)	2,227,430	-	-	2,227,430	
22	Land Rights, City Other Distribution System, Loc	374 41	13		-	13			13	
23	Rights of Way	374 50	3,233,107	(3 15)	-	3,233,104			3,233,104	
24	Structures, City Gate Measurement & Regulating	375 20	7,026	-	-	7,026			7,026	
25	Structures, General Meas & Reg Local Gas	375 31	4,012			4,012			4,012	
26	Structures, Regulating	375 40	3,543,546	8,505 27	(6,387 97)	3,545,663	3,169	(1,752)	3,547,080	
27	Structures, Distribution Industrial M&R	375 60	87,670	-	-	87,670	-	-	87,670	
28	Structures, Other Distribution System	375 70	6,890,015	(561,025 51)	-	6,328,989	227,799	-	6,556,789	
29	Structures, Other Distribution System, Leased	375 71	1,125,911	-	-	1,125,911	125,673	-	1,251,583	
30	Structures, Communication	375 80	16,515	-	-	16,515			16,515	
31	Mains									
32	Mains	376 00	952,372,290	18,386,925 78	(317,799 34)	970,441,417	14,851,777	(615,729)	984,677,465	
33	Mains - CSL Replacements	376 08	23,839,398	-	(309 68)	23,839,089	-	-	23,839,089	
34	Bare Steel	376 30	69,805,221	-	(113,057 39)	69,692,164	-	(135,696)	69,556,468	
35	Cast Iron	376 80	539,792	-	(3,035 66)	536,756			536,756	
36	Measuring & Regulating Equipment General	378 10	56,338	-	-	56,338			56,338	
37	Measuring & Regulating Equipment Regulating	378 20	31,652,547	110,570 79	(40,826 05)	31,722,292	1,108,126	(4,055)	32,826,363	
38	Measuring & Regulating Equipment Local Gas	378 30	463,732	-	(1,942 03)	461,790	-	-	461,790	
39	Measuring & Regulating Equipment City Gate	379 10	141,567	-	-	141,567			141,567	
40	Measuring & Regulating Equipment Exchange Gas	379 11	(450)	-	-	(450)			(450)	
41	Services	380 00	394,686,560	3,668,373 38	(488,700 93)	397,866,232	4,843,531	(485,616)	402,224,147	
42	Meters	381 00	34,680,366	121,725 71	(26,759 04)	34,775,332	123,425	(34,622)	34,864,136	
43	Auto Meter Reading Devices	381 10	23,310,025	-	-	23,310,025	88,604	-	23,398,629	
44	Meter Installations	382 00	34,768,902	52,942 47	(8,196 00)	34,813,649	184,909	(9,741)	34,988,817	34829682
45	House Regulators	383 00	10,693,867	38,574 63	(681 51)	10,731,560	39,090	(919)	10,769,731	
46	House Regulators Installations	384 00	3,864,772	-	-	3,864,772	-	-	3,864,772	
47	Industrial M&R Equipment Station Equipment	385 00	5,545,998	2,762 30	(3,591 49)	5,545,169	78,215	(26,384)	5,596,999	
48	Industrial M&R Equipment Large Volume	385 10	1,167,334	-	(282 11)	1,167,052	-	(10,718)	1,156,334	
49	Other Equipment	387 10	16,603	-	-	16,603	-	-	16,603	
50	Other Equipment, Odorization	387 20	117,248	-	-	117,248	-	-	117,248	
51	Other Equipment, Radio	387 42	121,945			121,945	-	-	121,945	
52	Other Equipment, Other Communications	387 44	635,499			635,499			635,499	
53	Other Equipment, Telemetering	387 45	3,642,174	504,713 55	(5,993 27)	4,140,894	1,168,624	-	5,309,518	
54	Other Equipment, Customer Information Service	387 46	259,436	-	-	259,436	-	-	259,436	
							-	-		
55	**General Plant**									
56	Structures, Communications	390 10	49,821		-	49,821	-	-	49,821	
57	Office Furniture & Equipment, Unspecified	391 10	1,855,896	556,225 51	-	2,412,121	-	(4,213)	2,407,908	
58	Office Furniture & Equipment, Data handling Equip	391 11	24,427	-	-	24,427	-	-	24,427	
59	Office Furniture & Equipment, Information Systems	391 12	2,571,448	-	-	2,571,448	-	-	2,571,448	
60	Office Furniture & Equipment, Air Condition Equip	391 20	3,007	-	-	3,007	-	-	3,007	
61	Transportation Equipment, Trailers > $1,000	392 20	86,703	-	-	86,703			86,703	
62	Transportation Equipment, Trailers $1,000 or <	392 21	10,830	-	-	10,830	-	-	10,830	
63	Stores Equipment	393 00	16,675	-	-	16,675	-	-	16,675	
64	Tools, Garage & Service Equipment	394 10	100,115	-	-	100,115	-	-	100,115	
65	Tools, CNG Equipment, Stationary	394 11	1,774,190		-	1,774,190	-	-	1,774,190	
66	Tools, CNG Equipment, Portable	394 12	179,308	-	-	179,308	-	-	179,308	
67	Tools, Shop Equipment	394 20	66,773	-	-	66,773	-	-	66,773	
68	Tools, Tools and Other	394 30	12,470,608	13,105 25	-	12,483,713	27,524	(32,906)	12,478,331	
69	Tools, High Pressure Stopping	394 31	10,847	-	-	10,847	0	0	10,847	

70	Laboratory Equipment Gas	395 00	50,661	-	-	50,661	0	0	50,661
71	Power Operated Equipment	396 00	1,435,493	-	-	1,435,493	0	0	1,435,493
72	Communication Equipment	397 00	210,798	-	-	210,798	0	0	210,798
73	Communication Equipment, Telephone	397 10	342,306			342,306	0	0	342,306
74	Communication Equipment, Radio	397 20	963,101	0	0	963,101	0	0	963,101
75	Communication Equipment, Other	397 40	0	0	0	0	0	0	0
76	Communication Equipment, Telemetering	397 50	798,398	0	0	798,398	0	0	798,398
77	Miscellaneous Equipment	398 00	365,192	31,424 18	(315 85)	396,300	65,260	0	461,560
78	Total Gas Plant in Service		1,658,038,447	23,116,873	(1,031,748)	1,680,123,673	23,013,502	(1,382,352)	1,701,774,722

			Gas Plant in Service						
Line No.	Description	Account No. (1)	Plant Beginning Balance 9/30/2015 (2) $	Additions (3) $	Retirements (4) $	Balance as of 10/31/2015 (5 = 2+3+4) $	Additions (6) $	Retirements (7) $	Balance as of 11/30/2015 (8)=(5+6+7) $
1	**Intangible Plant**								
2	Organization Costs	301 00	100,099	0	0	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302 10	26,489	0	0	26,489	0	0	26,489
4	Intangible Plant, General	303 00	1,320,595	0	0	1,320,595	3,488,467	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303 30	17,605,267	38,755	0	17,644,022	661	0	17,644,683
6	**Underground Storage Plant**								
7	Land	350 10	23,882	0	0	23,882	0	0	23,882
8	Rights of Way	350 20	1,932	0	0	1,932	0	0	1,932
9	Compressor Station Structures	351 20	3,138,952	0	0	3,138,952	51,937	0	3,190,890
10	Wells Construction	352 01	799,134	0	0	799,134	0	0	799,134
11	Wells Equipment	352 02	168,680	0	0	168,680	0	0	168,680
12	Storage Leasehold and Rights	352 10	139,442	0	0	139,442	0	0	139,442
13	Other Leases	352 12	67,498	0	0	67,498	0	0	67,498
14	Lines	353 00	405,288	0	0	405,288	0	0	405,288
15	Compressor Station Equipment	354 00	864,752	0	0	864,752	0	0	864,752
16	Measuring & Regulating Equipment	355 00	123,010	0	0	123,010	0	0	123,010
17	**Distribution Plant**								
18	Land, City Gate/Main Line Industrial	374 10	21,944	0	0	21,944	0	0	21,944
19	Land, Other Distribution System	374 20	479,275	0	(2,157)	477,118	0	0	477,118
20	Land Rights, City Gate/Main Line	374 30	95,361	0	0	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374 40	2,227,430	12,581	(296)	2,239,715	20,919	0	2,260,634
22	Land Rights, City Other Distribution System, Loc	374 41	13	0	0	13	0	0	13
23	Rights of Way	374 50	3,233,104	0	0	3,233,104	0	0	3,233,104
24	Structures, City Gate Measurement & Regulating	375 20	7,026	0	0	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375 31	4,012	0	0	4,012	0	0	4,012
26	Structures, Regulating	375 40	3,547,080	27,703	0	3,574,783	18,578	5,147	3,598,508
27	Structures, Distribution Industrial M&R	375 60	87,670	0	0	87,670	0	0	87,670
28	Structures, Other Distribution System	375 70	6,556,789	607	0	6,557,396	33,123	0	6,590,519
29	Structures, Other Distribution System, Leased	375 71	1,251,583	75,429	0	1,327,012	428,092	(81,213)	1,673,890
30	Structures, Communication	375 80	16,515	0	0	16,515	-	-	16,515
31	Mains								
32	Mains	376 00	984,677,465	12,757,625	(800,364)	996,634,727	14,045,705	(1,382,630)	1,009,297,802
33	Mains - CSL Replacements	376 08	23,839,089	0	0	23,839,089	0	0	23,839,089
34	Bare Steel	376 30	69,556,468	0	(191,368)	69,365,100	0	(159,522)	69,205,578
35	Cast Iron	376 80	536,756	0	(120)	536,637	0	(2,275)	534,362
36	Measuring & Regulating Equipment General	378 10	56,338	0	0	56,338	0	0	56,338
37	Measuring & Regulating Equipment Regulating	378 20	32,826,363	1,892,450	(35,337)	34,683,475	(2,619,419)	(42,814)	32,021,242
38	Measuring & Regulating Equipment Local Gas	378 30	461,790	0	0	461,790	0	0	461,790
39	Measuring & Regulating Equipment City Gate	379 10	141,567	0	0	141,567	0	0	141,567
40	Measuring & Regulating Equipment Exchange Gas	379 11	(450)	0	0	(450)	0	0	(450)
41	Services	380 00	402,224,147	4,163,598	(494,225)	405,893,520	6,242,259	(1,307,848)	410,827,931
42	Meters	381 00	34,864,136	193,202	(26,405)	35,030,932	141,527	(25,636)	35,146,824
43	Auto Meter Reading Devices	381 10	23,398,629	151	0	23,398,780	0	0	23,398,780
44	Meter Installations	382 00	34,988,817	118,504	(51,642)	35,055,679	182,321	(23,236)	35,214,764
45	House Regulators	383 00	10,769,731	38,820	(1,025)	10,807,526	48,895	(2,039)	10,854,383
46	House Regulators Installations	384 00	3,864,772	0	0	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment Station Equipment	385 00	5,596,999	57,851	(46,871)	5,607,980	(457,944)	(24,420)	5,125,616
48	Industrial M&R Equipment Large Volume	385 10	1,156,334	0	(2,308)	1,154,026	0	(2,207)	1,151,819
49	Other Equipment	387 10	16,603	0	0	16,603	0	0	16,603
50	Other Equipment, Odorization	387 20	117,248	0	0	117,248	0	0	117,248
51	Other Equipment, Radio	387 42	121,945	0	0	121,945	0	0	121,945
52	Other Equipment, Other Communications	387 44	635,499	0	0	635,499	0	0	635,499
53	Other Equipment, Telemetering	387 45	5,309,518	36,417	0	5,345,935	(2,016,949)	0	3,328,986
54	Other Equipment, Customer Information Service	387 46	259,436	0	0	259,436	0	0	259,436
55	GPS Pipe Locators	387 50	0	0	0	0	2,053,366	0	2,053,366
56	**General Plant**								
57	Structures, Communications	390 10	49,821	0	0	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391 10	2,407,908	0	(9,190)	2,398,718	69,166	(781)	2,467,103
59	Office Furniture & Equipment, Data handling Equip	391 11	24,427	0	0	24,427	0	0	24,427
60	Office Furniture & Equipment, Information Systems	391 12	2,571,448	28	0	2,571,475	845,519	0	3,416,995
61	Office Furniture & Equipment, Air Condition Equip	391 20	3,007	0	0	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392 20	86,703	0	0	86,703	0	0	86,703
63	Transportation Equipment, Trailers $1,000 or <	392 21	10,830	0	0	10,830	0	0	10,830
64	Stores Equipment	393 00	16,675	0	0	16,675	0	0	16,675
65	Tools, Garage & Service Equipment	394 10	100,115	0	0	100,115	0	0	100,115
66	Tools, CNG Equipment, Stationary	394 11	1,774,190	0	0	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394 12	179,308	0	0	179,308	0	0	179,308
68	Tools, Shop Equipment	394 20	66,773	0	0	66,773	0	0	66,773
69	Tools, Tools and Other	394 30	12,478,331	26,896	(1,744)	12,503,484	80,498	(69,799)	12,514,183
70	Tools, High Pressure Stopping	394 31	10,847	0	0	10,847	0	0	10,847
71	Laboratory Equipment Gas	395 00	50,661	0	0	50,661	0	0	50,661
72	Power Operated Equipment	396 00	1,435,493	0	0	1,435,493	0	0	1,435,493
73	Communication Equipment	397 00	210,798	0	0	210,798	0	0	210,798
74	Communication Equipment, Telephone	397 10	342,306	0	0	342,306	0	(13,008)	329,299
75	Communication Equipment, Radio	397 20	963,101	0	(963,101)	0	0	0	0
76	Communication Equipment, Other	397 40	0	0	0	0	0	0	0

77	Communication Equipment, Telemetering	397 50	798,398	0	0	798,398	0	0	798,398
78	Miscellaneous Equipment	398 00	461,560	24,502	(3,781)	482,281	12,498	(1,562)	493,217
79	**Total Gas Plant in Service**		1,701,774,722	19,466,119	(2,629,933)	1,718,609,908	22,669,218	(3,133,843)	1,738,145,284

			Gas Plant in Service			
	Description	Account No. (1)	Plant Beginning Balance 11/30/2015 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2015 (5 = 2+3+4) $
1	**Intangible Plant**					
2	Organization Costs	301 00	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302 10	26,489	0	0	26,489
4	Intangible Plant, General	303 00	4,809,062	0	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303 30	17,644,683	242,620	0	17,887,303
6	**Underground Storage Plant**					
7	Land	350 10	23,882	0	0	23,882
8	Rights of Way	350 20	1,932	0	0	1,932
9	Compressor Station Structures	351 20	3,190,890	93	0	3,190,983
10	Wells Construction	352 01	799,134	0	0	799,134
11	Wells Equipment	352 02	168,680	0	0	168,680
12	Storage Leasehold and Rights	352 10	139,442	0	0	139,442
13	Other Leases	352 12	67,498	0	0	67,498
14	Lines	353 00	405,288	0	0	405,288
15	Compressor Station Equipment	354 00	864,752	0	0	864,752
16	Measuring & Regulating Equipment	355 00	123,010	0	0	123,010
			0	0	0	
17	**Distribution Plant**		0	0	0	
18	Land, City Gate/Main Line Industrial	374 10	21,944	0	0	21,944
19	Land, Other Distribution System	374 20	477,118	0	0	477,118
20	Land Rights, City Gate/Main Line	374 30	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374 40	2,260,634	23,165	(13)	2,283,786
22	Land Rights, City Other Distribution System, Loc	374 41	13	0	0	13
23	Rights of Way	374 50	3,233,104	18	0	3,233,122
24	Structures, City Gate Measurement & Regulating	375 20	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375 31	4,012	0	0	4,012
26	Structures, Regulating	375 40	3,598,508	231,822	(17,579)	3,812,750
27	Structures, Distribution Industrial M&R	375 60	87,670	0	0	87,670
28	Structures, Other Distribution System	375 70	6,590,519	130,680	0	6,721,199
29	Structures, Other Distribution System, Leased	375 71	1,673,890	(3,309)	0	1,670,582
30	Structures, Communication	375 80	16,515	0	0	16,515
31	Mains					
32	Mains	376 00	1,009,297,802	15,674,106	(2,898,356)	1,022,073,552
33	Mains - CSL Replacements	376 08	23,839,069	0	0	23,839,069
34	Bare Steel	376 30	69,205,578	0	(332,795)	68,872,783
35	Cast Iron	376 80	534,362	0	(11,309)	523,053
36	Measuring & Regulating Equipment General	378 10	56,338	0	(1,007)	55,331
37	Measuring & Regulating Equipment Regulating	378 20	32,021,242	11,718,830	(50,759)	43,689,313
38	Measuring & Regulating Equipment Local Gas	378 30	461,790	0	0	461,790
39	Measuring & Regulating Equipment City Gate	379 10	141,567	0	0	141,567
40	Measuring & Regulating Equipment Exchange Gas	379 11	(450)	0	0	(450)
41	Services	380 00	410,827,931	3,753,207	(22,403)	414,558,735
42	Meters	381 00	35,146,824	157,188	0	35,304,012
43	Auto Meter Reading Devices	381 10	23,398,780	0	0	23,398,780
44	Meter Installations	382 00	35,214,764	269,518	0	35,484,282
45	House Regulators	383 00	10,854,383	145,471	0	10,999,854
46	House Regulators Installations	384 00	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment Station Equipment	385 00	5,125,616	24,217	(16,078)	5,133,755
48	Industrial M&R Equipment Large Volume	385 10	1,151,819	0	(2,708)	1,149,112
49	Other Equipment	387 10	16,603	0	0	16,603
50	Other Equipment, Odorization	387 20	117,248	0	0	117,248
51	Other Equipment, Radio	387 42	121,945	0	0	121,945
52	Other Equipment, Other Communications	387 44	635,499	0	0	635,499
53	Other Equipment, Telemetering	387 45	3,328,986	51,479	0	3,380,465
54	Other Equipment, Customer Information Service	387 46	259,436	0	0	259,436
55	GPS Pipe Locators	387 50	2,053,366	0	0	2,053,366
56	**General Plant**					
57	Structures, Communications	390 10	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391 10	2,467,103	1,034,350	(12,757)	3,488,696
59	Office Furniture & Equipment, Data handling Equip	391 11	24,427	0	0	24,427
60	Office Furniture & Equipment, Information Systems	391 12	3,416,995	341,801	0	3,758,796
61	Office Furniture & Equipment, Air Condition Equip	391 20	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392 20	86,703	4,197	0	90,900
63	Transportation Equipment, Trailers $1,000 or <	392 21	10,830	0	0	10,830
64	Stores Equipment	393 00	16,675	0	0	16,675
65	Tools, Garage & Service Equipment	394 10	100,115	0	0	100,115
66	Tools, CNG Equipment, Stationary	394 11	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394 12	179,308	0	0	179,308
68	Tools, Shop Equipment	394 20	66,773	0	0	66,773
69	Tools, Tools and Other	394 30	12,514,183	790,836	(6,985)	13,298,034
70	Tools, High Pressure Stopping	394 31	10,847	0	0	10,847
71	Laboratory Equipment Gas	395 00	50,661	0	0	50,661
72	Power Operated Equipment	396 00	1,435,493	0	0	1,435,493
73	Communication Equipment	397 00	210,798	0	0	210,798
74	Communication Equipment, Telephone	397 10	329,299	0	(160,468)	168,831
75	Communication Equipment, Radio	397.20	0	0	0	0
76	Communication Equipment, Other	397 40	0	0	0	0
77	Communication Equipment, Telemetering	397 50	798,398	0	0	798,398
78	Miscellaneous Equipment	398 00	493,217	328,456	0	821,674

79	Total Gas Plant in Service		1,738,145,284	34,918,748	(3,533,218)	1,769,530,815

SUMMARY

Line No.	Description	Account No. (1)	Plant Beginning Balance 11/30/2014 (2) $	Additions (3) $	Retirements (4) $	Balance as of 12/31/2015 (5 = 2+3+4) $
1	Intangible Plant					
2	Organization Costs	301 00	100,099	0	0	100,099
3	Franchises/Consent, Perpetual	302 10	26,489	0	0	26,489
4	Intangible Plant, General	303 00	1,320,595	3,488,467	0	4,809,062
5	Intangible Plant, Miscellaneous Software	303 30	16,993,538	1,354,496	(460,731)	17,887,303
			0			
6	Underground Storage Plant		0			
7	Land	350 10	23,882	0	0	23,882
8	Rights of Way	350 20	1,932	0	0	1,932
9	Compressor Station Structures	351 20	3,413,834	(222,852)	0	3,190,983
10	Wells Construction	352 01	799,134	0	0	799,134
11	Wells Equipment	352 02	168,680	0	0	168,680
12	Storage Leasehold and Rights	352 10	139,442	0	0	139,442
13	Other Leases	352 12	67,498	0	0	67,498
14	Lines	353 00	405,288	0	0	405,288
15	Compressor Station Equipment	354 00	584,073	280,679	0	864,752
16	Measuring & Regulating Equipment	355 00	123,010	0	0	123,010
17	Distribution Plant					
18	Land, City Gate/Main Line Industrial	374 10	21,944	0	0	21,944
19	Land, Other Distribution System	374 20	479,275	0	(2,157)	477,118
20	Land Rights, City Gate/Main Line	374 30	95,361	0	0	95,361
21	Land Rights, City Other Distribution System	374 40	2,128,782	172,302	(17,299)	2,283,786
22	Land Rights, City Other Distribution System, Loc	374 41	13	0	0	13
23	Rights of Way	374 50	3,233,107	15	0	3,233,122
24	Structures, City Gate Measurement & Regulating	375 20	7,026	0	0	7,026
25	Structures, General Meas & Reg Local Gas	375 31	4,012	0	0	4,012
26	Structures, Regulating	375 40	3,347,923	495,461	(30,634)	3,812,750
27	Structures, Distribution Industrial M&R	375 60	87,670	0	0	87,670
28	Structures, Other Distribution System	375 70	5,060,838	1,660,360	0	6,721,199
29	Structures, Other Distribution System, Leased	375 71	1,125,911	625,884	(81,213)	1,670,582
30	Structures, Communication	375 80	16,515	0	0	16,515
31	Mains		0	0	0	
32	Mains	376 00	889,710,839	142,128,965	(9,766,253)	1,022,073,552
33	Mains - CSL Replacements	376 08	23,839,553	0	(465)	23,839,089
34	Bare Steel	376 30	70,618,980	(14,656)	(1,731,541)	68,872,783
35	Cast Iron	376 80	570,600	0	(47,547)	523,053
36	Measuring & Regulating Equipment General	378 10	56,453	0	(1,122)	55,331
37	Measuring & Regulating Equipment Regulating	378 20	29,250,421	14,778,284	(339,392)	43,689,313
38	Measuring & Regulating Equipment Local Gas	378 30	457,281	0	4,509	461,790
39	Measuring & Regulating Equipment City Gate	379 10	141,567	0	0	141,567
40	Measuring & Regulating Equipment Exchange Gas	379 11	(450)	0	0	(450)
41	Services	380 00	387,198,097	32,630,993	(5,270,356)	414,558,735
42	Meters	381 00	34,123,146	1,580,826	(399,960)	35,304,012
43	Auto Meter Reading Devices	381 10	22,928,475	470,305	0	23,398,780
44	Meter Installations	382 00	34,184,825	1,448,497	(149,040)	35,484,282
45	House Regulators	383 00	10,430,768	582,632	(13,547)	10,999,854
46	House Regulators Installations	384 00	3,864,772	0	0	3,864,772
47	Industrial M&R Equipment Station Equipment	385 00	5,526,196	(227,816)	(164,626)	5,133,755
48	Industrial M&R Equipment Large Volume	385 10	1,189,991	0	(40,880)	1,149,112
49	Other Equipment	387 10	16,603	0	0	16,603
50	Other Equipment, Odorization	387 20	117,248	0	0	117,248
51	Other Equipment, Radio	387 42	121,945	0	0	121,945
52	Other Equipment, Other Communications	387 44	656,004	175	(20,680)	635,499
53	Other Equipment, Telemetering	387 45	2,087,866	1,298,592	(5,993)	3,380,465
54	Other Equipment, Customer Information Service	387 46	259,436	0	0	259,436
55	GPS Pipe Locators	387 50	0	2,053,366	0	2,053,366
56	General Plant				0	
57	Structures, Communications	390 10	49,821	0	0	49,821
58	Office Furniture & Equipment, Unspecified	391 10	2,944,321	1,671,009	(1,126,635)	3,488,696
59	Office Furniture & Equipment, Data handling Equip	391 11	49,805	0	(25,378)	24,427
60	Office Furniture & Equipment, Information Systems	391 12	2,197,893	1,560,902	0	3,758,796
61	Office Furniture & Equipment, Air Condition Equip	391 20	3,007	0	0	3,007
62	Transportation Equipment, Trailers > $1,000	392 20	110,152	4,197	(23,449)	90,900
63	Transportation Equipment, Trailers $1,000 or <	392 21	10,830	0	0	10,830
64	Stores Equipment	393 00	16,675	0	0	16,675
65	Tools, Garage & Service Equipment	394 10	122,964	0	(22,849)	100,115
66	Tools, CNG Equipment, Stationary	394 11	1,774,190	0	0	1,774,190
67	Tools, CNG Equipment, Portable	394 12	179,308	0	0	179,308
68	Tools, Shop Equipment	394 20	72,307	0	(5,534)	66,773
69	Tools, Tools and Other	394 30	12,181,053	1,847,404	(730,423)	13,298,034
70	Tools, High Pressure Stopping	394 31	10,847	0	0	10,847
71	Laboratory Equipment Gas	395 00	72,218	0	(21,557)	50,661
72	Power Operated Equipment	396 00	1,435,493	0	0	1,435,493
73	Communication Equipment	397 00	210,798	0	0	210,798
74	Communication Equipment, Telephone	397 10	342,306	0	(173,476)	168,831
75	Communication Equipment, Radio	397 20	2,339,889	0	(2,339,888)	0
76	Communication Equipment, Other	397 40	0	0	0	0
77	Communication Equipment, Telemetering	397 50	828,223	0	(29,825)	798,398
78	Miscellaneous Equipment	398 00	570,771	469,391	(218,487)	821,674
79	Total Gas Plant in Service		1,582,649,362	210,137,880	(23,256,427)	1,769,530,815

Columbia Gas of Pennsylvania, Inc.
Property, Plant & Equipment - Budget to Actual C
2014 Rate Case at Docket R-2014-240627

Additions

Ln. No.	Month (1)	Budget Month (2) ($)	Budget Cummulative (3) ($)	Actuals Month (4) ($)	Actuals Cummulative (5) ($)
1	11/30/2014	14,176,800	191,086,100	24,917,322	207,390,488
2	12/31/2014	15,924,300	207,010,400	13,348,436	220,738,924
3	1/31/2015	7,743,400	214,753,800	1,718,523	222,457,447
4	2/28/2015	6,968,500	221,722,300	4,688,425	227,145,873
5	3/31/2015	11,595,500	233,317,800	5,173,492	232,319,364
6	4/30/2015	12,455,300	245,773,100	6,651,393	238,970,757
7	5/31/2015	12,459,600	258,232,700	23,967,327	262,938,085
8	6/30/2015	20,920,200	279,152,900	17,399,000	280,337,084
9	7/31/2015	15,915,300	295,068,200	14,007,823	294,344,907
10	8/31/2015	21,437,700	316,505,900	23,116,873	317,461,780
11	9/30/2015	17,935,800	334,441,700	23,013,502	340,475,282
12	10/31/2015	15,824,700	350,266,400	19,465,119	359,940,401
13	11/30/2015	14,133,500	364,399,900	22,669,218	382,609,620
14	12/31/2015	21,261,400	385,661,300	34,918,748	417,528,368

Retirements

Ln. No.	Month (1)	Budget Month (2) ($)	Budget Cummulative (3) ($)	Actuals Month (4) ($)	Actuals Cummulative (5) ($)
1	11/30/2014	(2,325,942)	(16,911,842)	(1,517,403)	(17,162,867)
2	12/31/2014	(3,339,691)	(20,251,533)	(2,988,622)	(20,151,489)
3	1/31/2015	(586,000)	(20,837,533)	(919,579)	(21,071,068)
4	2/28/2015	(521,700)	(21,359,233)	(351,134)	(21,422,202)
5	3/31/2015	(890,200)	(22,249,433)	(425,770)	(21,847,973)
6	4/30/2015	(932,000)	(23,181,433)	(3,505,720)	(25,353,693)
7	5/31/2015	(929,700)	(24,111,133)	(904,070)	(26,257,763)
8	6/30/2015	(1,571,300)	(25,682,433)	(1,287,901)	(27,545,664)
9	7/31/2015	(1,193,500)	(26,875,933)	(1,182,537)	(28,728,201)
10	8/31/2015	(1,606,700)	(28,482,633)	(1,031,748)	(29,759,949)
11	9/30/2015	(1,345,800)	(29,828,433)	(1,362,352)	(31,122,301)
12	10/31/2015	(1,183,300)	(31,011,733)	(2,629,933)	(33,752,234)
13	11/30/2015	(1,085,700)	(32,097,433)	(3,133,843)	(36,886,077)
14	12/31/2015	(3,996,489)	(36,093,922)	(3,533,218)	(40,419,294)

Gross Plant in Ser

Ln. No.	Month (1)	Budget Month (2) ($)	Budget Cummulative (3) ($)	Actuals Month (4) ($)	Actuals Cummulative (5) ($)
1	11/30/2014	11,850,858	11,850,858	23,399,919	23,399,919
2	12/31/2014	12,584,609	24,435,467	10,359,814	33,759,733
3	1/31/2015	7,157,400	31,592,867	798,944	34,558,677
4	2/28/2015	6,446,800	38,039,667	4,337,291	38,895,968
5	3/31/2015	10,705,300	48,744,967	4,747,722	43,643,690
6	4/30/2015	11,523,300	60,268,267	3,145,672	46,789,362
7	5/31/2015	11,529,900	71,798,167	23,063,257	69,852,619
8	6/30/2015	19,348,900	91,147,067	16,111,099	85,963,719
9	7/31/2015	14,721,800	105,868,867	12,825,285	98,789,004
10	8/31/2015	19,831,000	125,699,867	22,085,125	120,874,130
11	9/30/2015	16,590,000	142,289,867	21,651,150	142,525,279
12	10/31/2015	14,641,400	156,931,267	16,835,186	159,360,465
13	11/30/2015	13,047,800	169,979,067	19,535,376	178,895,841
14	12/31/2015	17,264,911	187,243,978	31,385,531	210,281,371

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Month Over (Under) Budget (6)=(4-2) ($)	Cumulative Spend Over (Under) Budget (7)=(5-3) ($)	Over (Under) (8)=(7/3) (%)
10,740,522	16,304,388	8.53%
(2,575,864)	13,728,524	6.63%
(6,024,877)	7,703,647	3.59%
(2,280,075)	5,423,573	2.45%
(6,422,008)	(998,436)	-0.43%
(5,803,907)	(6,802,343)	-2.77%
11,507,727	4,705,385	1.82%
(3,521,200)	1,184,184	0.42%
(1,907,477)	(723,293)	-0.25%
1,679,173	955,880	0.30%
5,077,702	6,033,582	1.80%
3,640,419	9,674,001	2.76%
8,535,718	18,209,720	5.00%
13,657,348	31,867,068	8.26%

Month (Over) Under Budget (6)=(4-2) ($)	Cumulative (Over) Under Budget (7)=(5-3) ($)	Over (Under) (8)=(7/3) (%)
808,539	(251,025)	1.48%
351,069	100,044	-0.49%
(333,579)	(233,535)	1.12%
170,566	(62,969)	0.29%
464,430	401,460	-1.80%
(2,573,720)	(2,172,260)	9.37%
25,630	(2,146,630)	8.90%
283,399	(1,863,231)	7.25%
10,963	(1,852,268)	6.89%
574,952	(1,277,316)	4.48%
(16,552)	(1,293,868)	4.34%
(1,446,633)	(2,740,501)	8.84%
(2,048,143)	(4,788,644)	14.92%
463,272	(4,325,372)	11.98%
	-	

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Month Over (Under) Budget (6)=(4-2) ($)	Cululative Over (Under) Budget (7)=(5-3) ($)	Over (Under) (8)=(7/3) (%)
11,549,061	11,549,061	97.45%
(2,224,795)	9,324,266	38.16%
(6,358,456)	2,965,810	9.39%
(2,109,509)	856,301	2.25%
(5,957,578)	(5,101,277)	-10.47%
(8,377,628)	(13,478,905)	-22.36%
11,533,357	(1,945,548)	-2.71%
(3,237,801)	(5,183,348)	-5.69%
(1,896,515)	(7,079,863)	-6.69%
2,254,125	(4,825,737)	-3.84%
5,061,150	235,412	0.17%
2,193,786	2,429,198	1.55%
6,487,576	8,916,774	5.25%
14,120,620	23,037,394	12.30%

COLUMBIA STATEMENT NO. 7

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
	)	
	)	
vs.	)	Docket No. R-2016-2529660
	)	
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	
	)	

DIRECT TESTIMONY OF
WESLEY SOYSTER
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

Table of Contents

I. <u>Introduction</u>

Q. Please state your name and business address.

A. Wesley Soyster, 121 Champion Way, Suite 100, Canonsburg, PA 15317.

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

A. I am employed by NiSource Corporate Services Company as the Director of Construction for Pennsylvania, Maryland, Massachusetts, and Virginia.

Q. What are your responsibilities as Director of Construction?

A. My responsibilities include management of the following activities for Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company"):

- Execution of Columbia's Long Term Infrastructure Improvement Plan ("LTIIP");
- Installation of distribution pipeline facilities for adding new customers; and
- Relocation of distribution pipeline facilities for state, local and private development projects.

Q. Please briefly describe your professional experience.

A I graduated from The Pennsylvania State University with a Bachelor of Science Degree in Petroleum and Natural Gas Engineering. I also earned a Masters of Business Administration from Saint Francis University. Upon graduating from Penn State, I joined Columbia as an Operations Engineer responsible for the design of various pipeline replacement and addition projects in Southwestern Pennsylvania. In 2001, I jointed Equitable Gas Company ('EQT"), and over the next fifteen years, I held positions of increasing responsibility at both EQT and Peoples Natural Gas ("Peoples"). Those positions included Project Manager, Director of Engineering, Director of Construction, Vice President of Field Operations, and Vice President of Operations and Construction. I assumed my current position with Columbia in 2015.

Throughout my career, I have managed several functional areas, which include operations and maintenance ("O&M"), leak repair, engineering, construction, operations center dispatch, field customer service, gas measurement and regulation, corrosion, Distribution Integrity Management Programs ("DIMP"), Integrity Management Programs ("IMP") and damage prevention.

Q. Have you previously testified before the Pennsylvania Public Utility Commission?

A. Yes. I provided direct testimony for EQT's 2008 base rate case as well as the 2006 EQT-Peoples acquisition case.

Q. Please describe your membership in, or affiliation with, any industry organizations.

A. My industry affiliations include membership in the American Gas Association and the Energy Association of Pennsylvania.

Q. What is the purpose of your direct testimony?

A. I will provide an overview of Columbia's distribution system, discuss Columbia's ongoing replacement activities and provide testimony in support of Columbia's plant additions through the Fully Forecasted Rate Year (twelve-months ending December 31, 2017). I will also discuss Columbia's historic operating performance, the initiatives taken to improve its overall safety and compliance efforts and the metrics that are used to track performance and progress, and the planned system enhancements to Columbia's operations.

Finally, I will testify regarding Columbia's DIMP, the strategic O&M activities that it has undertaken to improve its system, and the additional O&M activities that Columbia is planning to undertake beginning in 2016.

II. Overview of Columbia's Pipeline Distribution System

Q. Please describe Columbia's distribution system.

A. Currently, Columbia serves more than 420,000 residential, industrial and commercial customers. The Company owns and operates a natural gas distribution system in 26 counties serving 450 communities spread across Pennsylvania. Columbia provides that service through approximately 7,460 miles of mains and approximately 422,052 services that it owns, operates, and maintains.[1] These facilities (as of January 1, 2016) are composed of approximately 1,415 miles of bare steel, 22 miles of cathodically protected bare steel, 30 miles of cast iron, 87 miles of wrought iron mains (in total, 1,554 miles of "first generation" main), and 53,494

[1] I note that in compliance with Section 1510 of the Pennsylvania Public Utility Code, in Western Pennsylvania the Company does not own the service lines all the way to the building, but terminates its ownership at the curb valve, typically found at or near the property line. If there is no curb valve on the service line, Columbia's ownership terminates at the property line itself. The customer then installs and maintains the remainder of the service line to the building.

bare steel services.[2] The balance of the system is comprised of cathodically protected coated steel, or plastic (polyethylene) mains and services, and 37.3 miles classified as other.[3]

Columbia's distribution infrastructure constitutes the final step in the delivery of natural gas to customers from the producing regions of the Southern United States, Western Canada, and in-state Pennsylvania-produced Marcellus and shallow well supplies. Columbia distributes natural gas by taking it from delivery points (or "city gates") along interstate pipelines, then transporting it through relatively small-diameter distribution mains and services that network underground through cities, towns, and neighborhoods in order to meet the demands of end-use customers. After taking delivery of natural gas at the city gate, Columbia then steps down the transmission pressure to local distribution pressure, further filters the gas to remove moisture and particulates that may damage Columbia's system, and then in some cases increases the amount of odorant known as mercaptan (the "rotten egg smell") to the natural gas before it is put into the distribution system. The gas then goes into the Columbia distribution system where the pressure is often further reduced to delivery pressure in a series of district regulator stations, before being

[2] The terms "bare steel," "unprotected coated steel," "unprotected steel," and "wrought iron" as explained further below, are used interchangeably and all refer to steel pipe without cathodic protection that is susceptible to corrosion.

[3] It should be noted that in 2011 Columbia deployed a Geographical Information System ("GIS") Mapping System to provide both mapping and data retrieval capabilities on its system and facilities. The 37.3 miles of "other" main appear to be anomalies in the data conversion and through a scrubbing process have been reduced from over 43 miles in 2013.

delivered to each customer. Once the gas is delivered on the customer's side of the meter (or the property line in Western Pennsylvania), it is owned by the customer and becomes the responsibility of the customer. In sum, Columbia's distribution system moves relatively small volumes of natural gas at lower pressures over shorter distances to a far greater number of individual users than its interstate pipeline counterparts.

Q. Please describe the years, types, and operating characteristics of the various pipe materials that have historically been installed in Columbia's system.

A. The system is comprised of many different types of pipe. From the 1850s to the early 1900s, Columbia's predecessor companies installed cast iron pipe throughout the early distribution systems. Cast iron, wrought iron and wood were among the first materials available, and cast iron had the advantage in that it was relatively strong and was easy to install. However, it was vulnerable to breakage from ground movement. When the pipe was buried to typical depths of between two and five feet, if the soil beneath the pipe or to its side was disturbed and pressure exerted on the pipe, it could crack. Further, each pipe section was not easily joined, so joints were prone to leaks. Finally, it was determined that it was unsuitable for long-distance transportation of gas because it was unable to withstand high pressures.

Q. How did the industry react to the problems present with the use of cast iron?

A. By the early 1900s, the industry had adopted steel and wrought iron piping for mains. These were deemed to be stronger than cast iron and able to withstand greater pressure. During this time, bare steel and wrought iron began replacing cast iron pipe as the material of choice when building a natural gas distribution system. During the pre- and post-World War II construction boom, gas utilities like Columbia, along with developers and customers, installed a significant amount of bare steel mains and services. Bare steel is steel pipe that has no exterior coating and has no cathodic protection installed on the pipe. The use of bare steel and wrought iron was common until the 1950s and 1960s when the industry began to realize that, despite its strength, bare steel was subject to corrosion and, in order to increase long-term safety and reliability, coating and cathodic protection should be applied to all new piping systems. Both exterior coatings and cathodic protection were designed to inhibit corrosion. Columbia installed its last bare steel pipe in the 1960s. By 1970, the federal government prohibited the installation of bare steel and wrought iron for natural gas distribution system infrastructure.

Q. What did the industry do to combat the problem of corrosion in bare steel?

A. The fact is that all metals corrode as a result of the natural process of chemical interactions with their physical environment, most commonly caused by moist soil (which creates an electrolyte) around the pipe. In these circumstances, direct electric current flows from the metal surface into the electrolyte and, as the metal ions leave the surface of the pipe, corrosion takes place. This current flows in the electrolyte to the site where oxygen or water is being reduced. This site is referred to as the cathode or cathodic site. In order to combat corrosion, natural gas distribution companies ("NGDCs") began using coated steel. Unprotected coated steel ("UPCS" or "coated steel") refers to steel pipe with an exterior coating (intended to electrically isolate the steel from the surrounding electrolytes in the soil).

Q. Did the use of UPCS solve the problem?

A. No, despite the best efforts of industry, and even though it was for a time an accepted industry standard, UPCS corroded as well. But for the period from the 1940s through the 1960s, as the industry assessed its options, it was one of just a few alternative piping materials available to meet the public demand for service. By 1970, Columbia had laid its last non-cathodically protected coated steel segment. Further, since that time Columbia has retrofitted all of its unprotected coated steel facilities with cathodic protection systems.

Q. What materials replaced bare steel and coated steel?

A. Coated steel pipe continues to be used, but it is cathodically protected with an electric current. The pipe breakthrough for the natural gas industry came in the mid-1960s with the introduction of plastic (polyethylene) pipe for gas distribution applications.

Q. What is "cathodic protection?"

A. Cathodic protection is a procedure by which underground metal pipe is protected against corrosion and deterioration (i.e., rusting and pitting) by applying an electrical current to the pipe. Cathodic protection reduces corrosion by making that surface the cathode and another metal the anode of an electrochemical cell. A primary function of a coating on a cathodically protected pipe is to reduce the surface area of exposed metal on the pipeline, thereby reducing the current necessary to cathodically protect the metal. At present, the principal methods for mitigating corrosion on underground steel pipelines are external coatings and cathodic protection.

Q. Has Columbia further improved the functionality of its piping since the introduction of cathodically protected steel?

A. Yes, it has. Cathodically protected steel has all the advantages of steel in terms of strength and, because of its impressed electrical current, is highly corrosion resistant. However, it is more costly to purchase and install, and requires more ongoing maintenance than the next generation pipe – plastic.

Q. What are the benefits of plastic pipe?

A. Plastic pipe has proven to be very good for distribution-level pressures. It has strength and flexibility, and, as a result, is generally immune to the stress of ground movement. Plastic is also less costly to purchase and easier to join and install than steel pipe. Plastic does not corrode and, therefore, does not require cathodic protection.

Q. Does plastic pipe have any drawbacks?

A. The two significant drawbacks to plastic include:

- Relative vulnerability to excavation damage as compared to cast iron or steel. As a result, excavators who do not dig by hand (despite being required to do so by One-Call laws) in the vicinity of plastic facilities are very likely to damage them. Cast iron and steel piping have greater tensile strength and thus are somewhat more likely to be able to resist external impact.
- "First Generation" plastic pipe, typically installed between 1970 and 1981 in most distribution systems and softer than today's "418 PE" material (due to the different composition of the base plastic material), has demonstrated itself to be prone to stress propagation cracking under some circumstances. Thus in certain limited cases, Columbia's first generation plastic pipe has generated Type-1 leaks due to significant longitudinal cracking along the pipe.

Q. What is Columbia doing to address these concerns?

A. Columbia has made significant progress in reducing facility damage rates. In 2007, damages per thousand locates were at 5.39. In 2015, damages per thousand locates were at 2.41. Efforts to improve locator performance and improved techniques for finding difficult to locate facilities have proven to be effective. However, overall damage prevention rates, while improved from historical levels, have plateaued over the last four years. Contractor negligence remains the highest cause of damages to our system and has increased from 47% of total damages in 2010, to nearly 54% of total damages in 2015. In an effort to reduce damages in this area further, Columbia has added four damage prevention coordinators to expand contractor outreach efforts. Columbia is continuing the practice of using "marker balls" when installing its new plastic facilities. These marker balls are placed in the ground above the pipe after it has been installed and enable Columbia to locate it later using electronic technology. As a result of the marker balls, Columbia has seen a 3-year declining trend in Contractor negligence.

Columbia is also deploying global positioning system ("GPS") mapping and locating technology that provides sub-decimeter accuracy in identifying the location of new or replacement facilities. This breakthrough technology will enable the Company to accurately locate its new facilities in the field. This will provide facility locators with a highly accurate, state-of-the-art ability to find facilities anywhere in the system that have been captured using this new technology. Thus, it has the clear potential to revolutionize our One-Call response procedures and the overall quality of facility locating. Columbia's plan is to capture all new and replacement installations using this new methodology, and simultaneously and systematically begin to capture existing system main and service information across the existing Columbia system, until we have captured detailed and accurate data on the entire system.

In order to address the issue that the industry has identified as "First Generation" plastic pipe, Columbia is replacing those sections of first generation plastic pipe that are uncovered in the course of executing the bare steel and cast iron replacement program, which I discuss later in my testimony. Further, depending on future failure rates of this first generation plastic pipe, and the relationship between those failure rates and other risks in the Columbia system at the time, Columbia's annual DIMP Plan risk evaluation may determine, at some point in the future, that a systematic program will be needed to replace the remainder of this softer, more vulnerable, first generation plastic material.

III. <u>Columbia's Pipeline Replacement Efforts</u>

Q. How many feet of bare steel, wrought iron, and cast iron main has been eliminated from the Columbia system during its accelerated program, and how does that trend compare with the previous years?

A. Columbia began an accelerated replacement of bare steel, wrought iron, and cast iron pipe in 2007. Between 2007 and the end of 2015, Columbia retired the following footages of bare steel, wrought iron, and cast iron by year:

	2007	355,764 feet
	2008	528,567 feet
	2009	344,488 feet
	2010	322,583 feet
	2011	533,765 feet
	2012	467,808 feet
	2013	449,856 feet
	2014	413,667 feet
	2015	513,216 feet
Total Actual	**(Through YE 2015)**	**3,929,714 feet**

From 2007 through 2015, Columbia's replacement program eliminated an average of 436,635 feet per year. During the 4 years from 2002 to 2005 the average annual rate of retirement was 196,948 feet, less than half the rate of retired footages of bare steel, wrought iron, and cast iron under the current program.

Q. **How have replacement costs trended and what are the primary cost drivers?**

A. Columbia has experienced upward cost pressure for replacement projects over the past several years. The average cost of main replacement in 2008 was $81.25 per foot, while the current average cost of main replacement, using 2014 actuals, is $182.30. The following factors create the upward cost pressure:

- The location of projects has a significant impact on cost. Hard surface projects in urban areas normally have a higher replacement cost per foot than soft surface replacement in rural areas, given similar size and material of pipe are being installed. The increased cost of urban areas can be due in part to the need to coordinate replacement of Columbia's facilities with facilities of other utilities or municipalities. These higher cost urban areas often have higher risk and are increasingly being prioritized for replacement, contributing to the increasing average cost per foot.

- Changes in hard surface restoration requirements are a key component of the upward cost pressures. Municipalities are expanding restoration requirements on utilities. For example, seven years ago it was typical that trench restoration would consist of simply paving the trench that was excavated for the main installation. Today, that same project frequently requires curb to curb milling and overlay. On other projects, Columbia is required to locate its facilities under sidewalks.. On these projects, Columbia is required to replace the entire sidewalk, and to the extent that the sidewalk does not meet American's with Disabilities Act ("ADA") standards, Columbia is required to make them compliant with current ADA standards. This means that Columbia may need to install wheelchair ramps and curb realignment or replacement work.
- Contractor cost is another key component of increased costs. Contractor cost increases are driven by competition for resources as more NGDCs in Pennsylvania and across the country undertake main replacement programs.
- The mix of plastic and steel mains and the diameter of the mains needed in the Company's system can affect the average main replacement cost. The

large, geographically dispersed nature of Columbia's system requires it to have a relatively high number of higher pressure steel, larger diameter mains to carry gas across the very broad western and eastern Pennsylvania Columbia service territories. As a result, far more of the facilities being replaced have to be designed and constructed of larger diameter pipe, with a larger percentage of steel (vs. lower cost plastic mains), compared to utilities that have smaller, more geographically compact service footprints. In fact, and by way of comparison, in 2012 Columbia had the largest average main diameter among all of the NiSource Gas Distribution Segment Local Distribution Companies, and its installation of steel replacement mains (vs. plastic mains) is also well above the NiSource Gas Distribution Segment average.

These combined factors have driven the unit cost for the Company's main replacements to increase materially over the last several years. This has necessitated greater capital spending by Columbia to keep pace with the replacement program's retirement footage objectives.

Q. What is Columbia doing to manage cost increases?

A. Columbia is focused on managing costs and making prudent capital investments that benefit our customers. As one of seven distribution companies within the NiSource family making infrastructure capital investments, we are able to negotiate at scale with contractors and suppliers, delivering competitive pricing for materials and services provided to Columbia.

Further, Columbia has initiated significant efforts regarding the management of permitting and restoration costs, which I describe later in my testimony. Columbia's service territory spans over 440 municipalities in the Commonwealth of Pennsylvania, each of whom are authorized to set their own municipal ordinances related to street openings. Columbia incurs restoration costs on pipeline replacement projects in compliance with the ordinance of the municipality in which the pipeline is replaced.

Q. Have municipal standards changed since the inception of Columbia's aggressive pipeline replacement program?

A. Yes. Over the past few years, Columbia notes that municipalities continue to change and update local ordinances regarding restoration requirements. Columbia replaces pipe in the following townships or boroughs, which require either curb to curb paving requirements or curb to center line paving requirements:

Curb to curb paving restoration requirements

- **Allegheny County:** Baldwin Township (2012), Bethel Park (2012), Borough of Castle Shannon (2008), Borough of Dormont (2013), Borough of Heidelberg (2005), Sewickley (2009), Edgeworth Township (2009), Green Tree Borough (2014)
- **Venango County:** Emlenton Borough (2012)

- **<u>Washington County:</u>** Amwell Township, Borough of Canonsburg (2013), Peters Township (2012)
- **<u>Westmoreland County:</u>** Borough of Scottdale (2013)

<u>Curb to center line paving restoration requirements</u>

- **Allegheny County:** Kennedy Township (2005)
- **Washington County:** McDonald Borough (2012)

Additionally, there are several municipalities in the Company's service territory, with ordinances designating that restoration requirements and standards are at the final discretion of the township or township engineer. These townships and boroughs include:

- Scott Township
- Borough of Pleasant Hills
- Stowe Township
- Castle Shannon
- Mt. Lebanon
- Ferguson Township
- City of Pittsburgh
- North Strabane Township

Q. What other challenges has Columbia faced regarding paving and restoration within Pennsylvania municipalities?

A. Columbia has completed work in areas where a municipality hired a third party engineering firm. These third party firms have an expectation of construction industry standards regarding paving on a pipeline replacement project. This means that the third party firms expect no seam paving jobs. Consequently, municipalities who hire third party engineering firms, typically require Columbia to pave beyond the area in which the Company's replacement project occurs.

Q. When a municipality requests restoration beyond the area in which Columbia's pipeline replacement activity occurs, what does Columbia do to resolve the issue?

A. When the Company encounters a situation in which a municipality requests atypical or non-PennDOT standard restoration requirements, Columbia tries to negotiate with the municipality, in order to reach a compromise. This approach helps Columbia maintain good rapport with townships and municipalities. Maintaining relationships with municipalities and townships is very important, especially in the unforeseen event of an emergency. Thus, negotiation is the initial starting point and preferred resolution method.

Further, while negotiation is the preferred method for resolution, sometimes a compromise cannot be reached. When a compromise cannot be reached, the Company further analyzes the situation to determine the best path to move forward. The Company can opt to pursue litigation or evaluate whether to move forward with the project. Whether or not to move forward with a project is evaluated on an individual project basis, as each situation presents unique circumstances.

Q. Has Columbia been successful in challenging restoration requirements?

A. Yes, we have. Below are a few examples:

- **Dellrose Street, City of Pittsburgh** – The City of Pittsburgh Public Works road restoration provisions required a complete rebuild of at least half the road from the base up. For Dellrose Street, which is a brick surface street, Columbia estimated that compliance with this requirement would have cost in excess of $1 million. Columbia negotiated a restoration plan to install permeable pavers, which reduced restoration costs by an estimated 30 percent.
- **City of Pittsburgh** – This was a collaborative effort among Columbia and other utilities to challenge the City's proposed "Major Street Opening Permit" revision that would have increased costs and possibly delayed pipeline replacement projects in Pittsburgh. Columbia Gas, working with the other utilities, was able to amend the bill to exclude utility infrastructure work. Also, challenged and successfully delayed for a year, the City's attempt to implement an increased requirement of four inch mill and overlay for pipeline replacement projects on major streets, resulting in savings of $100,000.

- **Cross Creek Township, Washington County** – Columbia successfully sought revision of a provision in a road maintenance agreement between Columbia and the Township which required 200 feet of mill and overlay paving curb to curb on each side of a road opening. Columbia successfully negotiated a restoration plan with the Township, saving more than $42,000 in restoration costs.

Q. What other challenges has Columbia encountered with municipalities associated with pipeline replacement projects?

A. While restoration requirements are the primary challenges faced by the Company in completing restoration projects, the Company has also successfully challenged other municipal requirements. Below is a brief list of some of the other challenges that Columbia has addressed:

- **Redevelopment Authority of Washington County** - Successful challenge of fair market value of easement on property necessary for pipeline replacement, resulting in savings of $30,000.
- **Connellsville** - Successful challenge of fair market value of easements on two pieces of city owned property necessary for pipeline replacement, resulting in savings of $22,500.
- **Leet Township** - Negotiating with township regarding a demand from the township engineer to provide highly detailed drawings for every road

opening made by Columbia on a proposed pipeline replacement in order to obtain a permit. Estimated cost of drawing was $25,000.

- **Ambridge Township** – Subsequent to a public meeting attended by Columbia to educate the residents about an upcoming pipeline replacement and prior to the commencement of our pipeline replacement project, the Township enacted new restoration ordinances. Columbia was able to successfully negotiate with the township restoration standards, which did not increase costs significantly for the planned project.

Q. **Going forward, how does Columbia intend to continue managing restoration costs?**

A. Columbia will continue to work with local governments in an effort to control permitting and restoration requirements for pipeline replacement projects. The Company's goal is to balance the requirements of local governments while delivering the best value for our customers. Columbia continues to engage local governments in an effort to maintain that balance.

Q. How does Columbia install pipe in its underground distribution system?

A. The initial installation of natural gas distribution pipe requires the excavation of a trench usually under or adjacent to a public street into which the pipe is laid. Then new or existing customer services are connected to the new main.

Installation of natural gas distribution pipe can be a major inconvenience for residents, business owners and municipalities. In some circumstances, where smaller diameter plastic facilities are installed to replace larger diameter steel piping, the cost and inconvenience associated with excavating a trench can be reduced by inserting the new pipe through the old piping. This involves smaller street cuts for the insertion plus smaller cuts associated with service line and intersecting main tie-ins. Further, even if a replacement main must be laid rather than inserted, the use of smaller plastic pipe, where viable, rather than larger steel or cast iron pipe will produce a savings in material costs.

Q. Why does Columbia need to continue to replace its bare steel and cast iron systems?

A. Columbia's DIMP risk scoring continues to rank external corrosion on bare steel and bell joint failure on cast iron pipelines among our top system risks. Corrosion on first generation mains represents nearly 81% of all hazardous or potentially hazardous leakage cleared on mains in the Columbia distribution system in 2015. Columbia has determined that there are an increasing number of leaks in areas where unprotected steel is concentrated. The Company believes that the accelerated replacement of the first generation system is not only prudent, but is a requirement under the federal DIMP rule that Columbia continues to address very aggressively in a consistent and programmatic way.

As a result, Columbia plans to maintain or increase its capital expenditures in the 2016 to 2020 timeframe, with a planned spending program ranging between $150 and $200 million budgeted annually for line replacement over the 5-year period. This budget includes the replacement of bare steel, cast iron, and wrought iron pipelines.

Q. Please explain Columbia's capital additions claimed for the Future Test Year and Fully Forecasted Rate Year.

A. The amounts shown are taken from Columbia's capital budget, as developed by our operations group and engineering department.

Further, for a detailed description of Columbia's age and condition actuals for 2015, and budgeted amounts for 2016, and 2017, please see the chart below.

Columbia Age & Condition Replacement Budgets ($000)

GPA	Description	Total 2015 Actual	Total 2016 Projected	Total 2017 Projected
354	Compressor Stations	8	50	57
376	Mains - Leakage Elimination	110,112	63,300	88,357
380	Service Lines – Replaced	37,346	45,000	53,550
376	Customer Service Lines Replaced	659	0	0
381	Meters / 998 Int. Co. Meters	0	0	0
382	Meter Install – Replace	496	1,250	1,653
383	House Regulators - Replace	36	150	228
378	Plant Regulators – Replace	978	1,750	3,133
375	Reg Structures Replace	111	200	228
385	LV Excess Press Meas Sta	171	100	114
376	Corrosion Mitigation Ins	152	100	114
376	Large Projects / Specifics/Misc	812	50,000	56,968
		150,881	161,900	204,402

Taken in total, Columbia has made enormous progress since 2006 in delivering and maintaining a safe and reliable distribution system for its customers. The progress that I refer to is defined in more detail throughout this testimony, but includes initiating an annual leakage survey on all of its bare steel mains, identification and mitigation of system cross bores, reducing the number of inactive services in the system, reducing its Type-2 leak repair backlog, improving the locating process to reduce third-party damage, improving emergency response rates and on-time appointments for customers, and dramatically increasing the amount of bare steel and cast iron pipe that it removes from the system annually. Having said all of that, however, the system data is clear that as first generation bare steel and cast iron pipe continues to age, Columbia will have to continue to focus on the accelerated replacement of bare steel and cast iron to address the problems associated with aging infrastructure. Therefore, it is essential that Columbia continue to direct management effort and incremental capital resources toward this ongoing need. The synchronization of these replacement efforts with the enhanced focus on pipeline safety that Columbia has demonstrated over the last 9 years are integral parts of Columbia's DIMP Plan, and are essential planks of Columbia's ongoing efforts to enhance natural gas pipeline integrity management and, thus, provide a safe, reliable distribution system for our customers and the general public.

Q. How do Columbia's bare steel replacement rates compare with other Pennsylvania NGDCs?

A. Columbia continues to reduce its bare steel inventory at a rate that exceeds its intrastate industry peers. In 2014 (the last date comparative data is available, Columbia replaced 78 miles of bare steel pipe, second only to the combined UGI companies. In 2015, Columbia replaced 97 miles of bare steel pipe (other PA NGDC data not yet available for 2015).

Q. Is there another solution for addressing the issues with bare steel and cast iron short of replacement?

A. No. Corrosion leakage on unprotected steel does not slow down and the rate of leakage will only accelerate as the unprotected steel facilities continue to deteriorate. First generation unprotected steel pipe, much of it dating to the turn of the last century, has reached or soon will reach the end of its useful life and must be replaced in a timely, cost-effective manner.

Q. Do safe and reliable system operations requirements demand replacement of Columbia's unprotected steel facilities?

A. Yes. Continual system degradation due to unrelenting corrosion will challenge Columbia's ability to meet peak day needs and operate the system safely. Therefore, continuing Columbia's main replacement program is essential to minimize leakage and the associated public risks and additional strain on the system when required to meet peak day demands.

Q. Are you saying Columbia's system is unsafe?

A. No, I am saying the system is safe right now, as evidenced by our ability to address

Type-1 and Type-2 leaks appropriately, as well as all of the other operational improvements including more frequent leakage surveys, better emergency leak response, and a continued focus to reduce the backlog of open Type-2 leaks that are described later in this testimony. Columbia's system is comprised of thousands of miles of wrought iron, cast iron, bare steel, cathodically-protected steel, and plastic pipe. The material initially at risk is generally first generation bare steel, cast iron, and wrought iron. Evidence further indicates that the corrosion with respect to unprotected coated steel is accelerating, gradually causing more leaks. Also, cast iron pipe is quite old and is in need of replacement due to its age and vulnerability to fractures caused by ground movement. Wrought iron is a hybrid of cast iron and bare steel that demonstrates very similar corrosion characteristics to that of bare steel.

With all of that said, while the system is currently safe, Columbia must, as a prudent operator, address the systemic problem of replacing its unprotected steel, cast iron, and wrought iron facilities. And finally, the issues that are manifesting themselves on first generation plastic (though the risks have not yet risen to the level of risk associated with bare steel, cast iron, or wrought iron), as discussed elsewhere in this testimony, also necessitate a measured replacement strategy geared to those locations where Columbia is uncovering this pipe in the course of replacing other facilities.

Q. How does Columbia classify leaks it detects on its system?

A. Columbia classifies each gas leak according to its severity: Type-1, Type-2, or Type-3. A Type-1 leak is hazardous and requires immediate remediation and repair. A Type-2 gas leak is non-hazardous at the time of detection, but requires a scheduled repair based on the potential for becoming a hazard. A Type-3 gas leak is defined as "non-hazardous at the time of detection and can be reasonably expected to remain non-hazardous."

These gas leak classifications are defined in the Gas Piping Technology Committee ("GPTC") American National Standards Institute ("ANSI") Z380.1 "Guide for Gas Transmission and Distribution Piping Systems." The Guide is commonly utilized by gas operators and State pipeline regulators, including the Commonwealth of Pennsylvania, as an interpretation of "DOT 192 2003 CFR Title 49, Part 192 Transportation Of Natural And Other Gas By Pipeline: Minimum Federal Safety Standards."

Q. Will Columbia's accelerated replacement program provide customers with any other benefits besides the replacement of bare steel, wrought iron, and cast iron pipe with plastic and cathodically protected steel?

A. Yes. Columbia is replacing the segmented, 19th and early 20th century low-pressure designs of its first generation system with a more integrated, 21st century system design. This integrated, higher pressure system (up to a maximum of 99 pounds operating pressure, though will typically operate at 60 pounds per square inch gauge ("PSIG") will enable Columbia to substantially reduce the current need for district pressure regulator stations throughout its system, resulting in a safer, easier, and more reliable system to operate. Instead, each residence will have a small domestic sized regulator installed just up-stream of the meter to reduce the pressure before it enters the house. Also a distribution system operating at these higher pressures will enable Columbia to install new safety devices in areas to be upgraded. As part of the upgrade, Columbia is installing excess flow valves on nearly all services connected to the replacement mains.[4] For approximately $25 per replaced residential service, or less than $150 for the average commercial service, these excess flow valves will shut off gas to a residence or business in the event of a large pressure differential, which is indicative of a major gas leak or a service damaged by excavation. Over time, this results in a system where services are much less vulnerable to safety risks from third-party damage.

Finally, this migration to higher pressure systems will provide customers with much more flexibility in adding new, high efficiency equipment, and in allowing for the installation of smaller, less expensive interior piping systems (such as CSST—Corrugated Stainless Steel Tubing), which is designed to operate at two pounds of inlet pressure (current low pressure systems typically operate at a maximum of 7 inches of water column, which is roughly 1/8th of the 2 PSIG pressure required).

Notably, the 60-pound system design discussed above provides the maximum flow

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[4] The exception would be for those commercial and industrial customers whose consumption is over 5,000 cubic feet per hour.

capacity for a given size of medium density polyethylene pipe, and enables the Company to routinely provide 2-pound pressure delivery systems to customers. It should also be noted that as a result of the quarter pound of pressure associated with low pressure delivery systems, this type of service (i.e., other less expensive 2 pound pressure systems) is not available to customers currently served from low pressure systems.

Q. How will main replacements affect the Company's leak repair experience?

A. The long term view is that as the percentage of bare steel, wrought iron, and cast iron pipe is materially diminished, we expect to see a reduction in Type 1 and Type 2 leakage repair caused by corrosion. However, this impact is not anticipated in the near term. The remaining cast iron, wrought iron, and bare steel pipe to be replaced continues to drive Type 1 and Type 2 leakage repair activities. In 2015, our pipe replacements, together with our aggressive leak repair program, allowed Columbia to reduce the total number of Type-2 outstanding leaks in the system to 950, a 75% reduction since 2007.

Q. How does the public benefit from Columbia's ongoing replacement of its aging facilities?

A. Columbia is removing deteriorating portions of its system and enhancing the safety of its system by ensuring replacement of facilities with new, longer lasting and safer materials. Its system will continue to be able to provide deliverability at its maximum allowable operating pressure ("MAOP"), thus the public will receive better service, with fewer interruptions. Customers currently experience the benefits of the investments being made to enhance the safe and reliable delivery of their natural gas service. During the "Polar Vortices" of both 2014 and 2015, Columbia's distribution system performed well and experienced no significant issues with service interruptions or curtailments of firm customers. The same has held true through the other cold weather events of the 2015-2016 winter heating season. Further, this massive and structural system replacement program is adding jobs throughout Columbia's service territory, both in the ranks of full-time Columbia employees (these include engineers and engineering technicians, land agents, and construction inspectors), as well as the contractors who perform the actual pipe replacement (which includes laborers, equipment operators, crew leaders, and support staff) and associated support services such as: paving, traffic control, trucking, sand and gravel, and a myriad of other material purchases and support activities that are needed to execute this type of strategic replacement program. Finally, to emphasize the magnitude of this program, at the peak of 2015 Columbia had 90+ construction crews employing approximately 500 to 600 contractors and 20 to 25 restoration contractors employing approximately 200 employees.

IV. Federal Pipeline Safety Rules and Advisories

Q. Please describe the Federal Pipeline Safety Rules and Advisories that are affecting and will continue to affect Columbia's Pipeline Safety Strategy and Operational Execution.

A. Some of the more significant and impactful Final Rules or Advisories issued in the last several years or that are being considered for the future, are as follows:

- Control Room Management (76 FR 35130) - This rule expedites the program implementation deadlines in the Control Room Management/Human Factors regulations in order to realize the safety benefits sooner than established in the original rule. This rule requires that Operators define the experience requirements, create training programs, and establish clear roles and responsibilities for Control Room Operators. Further, the rule mandates that appropriate shifts, and maximum hours of work be established for control room operations. The deadline for pipeline operators to implement the procedures for roles and responsibilities, shift change, change management, and operating experience, fatigue mitigation education and training was October 1, 2011, 16 months sooner than the original regulation.
- Mechanical Fitting Failure Reporting Requirements (76 FR 5494) - This final rule is an amendment to the Pipeline and Hazardous Materials Safety Administration's ("PHMSA") regulations involving DIMP. This final rule revises the pipeline safety regulations to clarify the types of pipeline fittings

involved in the compression coupling failure information collection, and changes the term "compression coupling" to "mechanical fitting," which aligns a threat category with the annual reporting requirements and clarifies the Excess Flow Valve ("EFV") metric to be reported by operators of gas systems. (As a result of this change from "compression fitting" to "mechanical fitting" Columbia is likely to report more "mechanical fitting" failures in its system than it has reported historically.)

- Integrity Management Program for Gas Distribution Pipelines (74 FR 63906) - this final rule amends the Federal Pipeline Safety Regulations to require operators of gas distribution pipelines to develop and implement integrity management ("IM") programs. The IM programs required by this rule are similar to those required for gas transmission pipelines, but tailored to reflect the differences in and among distribution facilities.

In addition to the final rules above, the following are proposed rules or recommendations that are currently being made by, or are under consideration by PHMSA:

- Pipeline Safety: Pipeline Damage Prevention Programs (PHMSA 2009-0192 RIN 2137-AE43) - This Advance Notice of Proposed Rulemaking seeks to revise the Pipeline Safety Regulations, in order to: establish criteria and procedures for determining the adequacy of state pipeline excavation damage prevention law enforcement programs; establish an administrative process for making adequacy determinations; establish the Federal requirements PHMSA will enforce in states with inadequate excavation damage prevention law enforcement programs; and establish the adjudication process for administrative enforcement proceedings against excavators where Federal authority is exercised. This requirement continues to work its way through the PHMSA regulatory approval process, and is expected to be approved. Further, unless the Pennsylvania Legislature passes the One Call Enforcement Bill that has been introduced, we are likely to see this federal enforcement in Pennsylvania which would have material impact on all Pennsylvania gas utilities.

- Pipeline Safety: Expanding the Use of Excess Flow Valves in Gas Distribution Systems to Applications Other Than Single-Family Residences (PHMSA 2011-0009 RIN 2137-AE71) – The National Transportation Safety Board has made a safety recommendation to PHMSA that excess flow valves be installed in all new and renewed gas service lines, regardless of a customer's classification, when the operating conditions are compatible with readily available valves. This requirement continues to work its way through the PHMSA regulatory approval process, and is expected to be approved. Columbia has already modified its procedures to require its construction crews to install excess flow valves on all new and replacement commercial installations up to 5,000 Cubic Feet Per Hour.

- Pipeline Safety: Safety of Gas Transmission Pipelines (PHMSA 2011-0023 RIN 2137-AE72) – PHMSA is considering whether changes are needed to the regulations governing the safety of gas transmission pipelines. In particular, PHMSA is considering whether IM requirements should be changed, including adding more prescriptive language in some areas, and whether other issues related to system integrity should be addressed by strengthening or expanding non-IM requirements. Among the specific issues PHMSA is considering concerning IM requirements is whether the definition of a high-consequence area should be revised, and whether additional restrictions should be placed on the use of specific pipeline assessment methods.
- NTSB Recommendation P-12-17 Safety Management System (API Draft Recommended Practice 1173) – Conceptually, this recommendation is built on the premise that managing the safety of a complex industry requires a system of efforts to address multiple, dynamic, changing activities, and circumstances. It further reflects the PHMSA view that if the industry is to achieve the goal of zero incidents, a highly structured and comprehensive effort is required. The broad components of these plans would include:
    - Demonstrated management commitment
    - Structured pipeline safety risk management decisions
    - Increased confidence in risk prevention and mitigation
    - Provide a platform for shared knowledge and lessons learned

- Promoting a pipeline safety oriented culture

The ultimate purpose of this initiative is intended to produce a continuous pipeline safety improvement cycle among pipeline operators of "Plan-Do-Check-Act."

Q. Will PHMSA's focus on Transmission Lines have any significant impact on Columbia operations?

A. Yes, "Transmission Line" is defined in CFR 49, Part 192 as "a pipeline, other than a gathering line, that: (1) transports gas from a gathering line or storage facility to a gas distribution center, storage facility, or large volume customer that is not down-stream of a distribution center; (2) operates at a hoop stress of 20 percent or more of SMYS [System Minimum Yield Strength]; or (3) transports gas within a storage field." Columbia has approximately 63.4 miles of transmission class facilities that meet this definition. Further, following the San Bruno California explosion which occurred on a Pacific Gas and Electric ("PG&E") Transmission Line in 2010, PHMSA has focused attention on the quality and comprehensiveness of system records for these lines, particularly around the pressure testing data, pipe design information, and wall thickness of existing transmission line systems. Because there was no federal mandate requesting such reports, Columbia, like many other NGDCs and transmission companies, is lacking certain data, particularly on segments installed prior to current code standards and the issuance of Federal Pipeline Safety Regulations instituted on August 1, 1971. The increased spending, shown in the Company's response to Standard Data Request GAS-ROR-014 in the capital budget category of "betterment" for 2016 and beyond, reflects increased pipe replacement work that Columbia expects to have to conduct on these pre-1971 transmission lines. PHMSA continues to focus heavily on Transmission Operations with a new Notice Of Proposed Rule-Making ("NOPR") that would either change the definition to make the inspection procedures and safety requirements of the various class locations more rigorous, or to expand the classification of High Consequence Areas, requiring changes in both system design criteria as well as on-going maintenance in those areas.

V. <u>Strategic O&M Initiatives</u>

Q. Please summarize the results of your assessment of Columbia's pipeline safety risks and opportunities.

A. In 2006, 2007, and 2008, Columbia undertook safety initiatives which included the following activities, among others:

- Conducting frequent leakage surveys on "first generation" facilities;
- Launching a structural "first generation" pipe replacement program;
- Undertaking a focused process to reduce third-party damage;
- Initiating a program to reduce the backlog of open Type-2 leaks; and
- Eliminating the backlog and accelerating the abandonment of inactive services.

In 2013, Columbia initiated the following additional safety initiatives to further enhance the safety of its distribution system:

- Aggressive management of right-of-way vegetation;
- Continued acceleration of the repair rate of open Type-2 leaks;
- Continued efforts to remediate atmospheric corrosion on above ground structures;
- Ensuring exposed mains have appropriate cover;
- Increased use of camera-based technology to identify cross-bore conflicts;
- Began to implement Hi-Accuracy GPS program;
- Expanded use of Vac Trucks to dig test holes on facilities where the existing tracer wires have either been broken or suffered degradation to the point there is no longer electrical continuity.
- Ensure MAOP documentation in compliance with federal requirements; and
- Enhanced damage prevention advertising and contractor outreach, with a particular emphasis on educational outreach to children through targeted educational programs

Q. Please discuss Columbia's strategy regarding O&M safety initiatives going forward.

A. Columbia's strategic DIMP Plan, and the impact that it will have on O&M policy for safety initiatives, remains unchanged. The Company continues to focus its efforts and resources on the top risks to the Company's system as enumerated in its DIMP Plan and as modified based on the annual DIMP data review, which sometimes results in risk reprioritizations or other updates to the plan. Columbia is expanding focus in several critical areas to maintain and enhance its operational capabilities:

- As Columbia works to build the pipeline of the future we also find ourselves in the midst of building the workforce of the future. With the ramp up of our capital program we have experienced the transfer of employees from O&M positions to construction positions; in addition we continue to see an increase in the number of employees who are eligible to retire. We see both opportunity and risk in the current and future transition of our workforce. Columbia's historical methods of training were developed in an era of very low turnover and well-established institutional knowledge. These traditional training methods will not address the increased risk of human error to our system introduced by this large scale workforce transition. We have adjusted our methods of training to reduce that risk for new and existing employees. Columbia is currently conducting a formal employee training and qualification program to address the DIMP and system risks associated with human error in the field. These programs will not only include more classroom time and far more stringent testing procedures, but will, where appropriate, require hands-on demonstrations of necessary skills to validate employee or contractor qualification competency. Columbia has made additional organizational changes to focus on training and development of employees. While this adds to current O&M expenses, it is vital that we are effective in preparing the next generation of employees, so as to minimize risk both to employees and the general public.

- Columbia is constructing a new training center that will open in mid-2016 and will provide the facilities needed to conduct classroom training and enhanced hands on training. The facility will be used for multiple training purposes, including: new employee training, employees transitioning into higher skilled positions, and annual refresher training for the existing workforce. A great deal of thought, research and best practices were considered when developing the new training approach and designing the training facility. Trainers traveled to industry leading training facilities and natural gas organizations across the country. The Company studied best practices of organizations outside the natural gas distribution industry, who are trained to respond to crisis and emergency situations. We formed focus groups to gain insight and obtain feedback from front-line employees about their perceptions of and experiences with training, as well as the accessibility of standards while performing on-the-job tasks. The developed curriculum will incorporate end-to-end training of Columbia's field technology, such as mobile data terminal units and work management systems, to technical training for operator qualifications. This end-to-end training will educate employees on every aspect of the job and its importance, from physical work performed to its accurate documentation. This facility will replace the Jeanette, Pennsylvania facility that was severely damaged in a tornado in March of 2011. As I noted above, the new facility will open in mid-2016.

- With the current and anticipated entry of new employees to the workforce, Columbia has also made adjustments to the span of control for frontline leaders. Historically, higher spans of control were manageable because of low turnover and a high level of workforce experience and tenure. The increased number of new employees entering the workforce requires frontline leaders to spend additional time providing guidance and supervision. To achieve an effective span of control, Columbia will continue to add Front Line Leader positions.
- As mentioned previously in my testimony, damage prevention continues to be a focus in reducing ongoing system risk. Columbia has made significant progress in reducing facility damage rates. In 2007 damages per thousand locates were at 5.39. Damages in 2015 were reduced to 2.41 damages per thousand locates. Efforts to improve locator performance and improved techniques for finding difficult to locate facilities have proven effective. However, overall damage prevention rates, while improved from

historical levels, have plateaued over the last three years. As I stated earlier in my testimony, contractor negligence remains the highest cause of damages to our system and has increased from 47% of total damages in 2010, to nearly 54% of total damages in 2015. In an effort to further reduce damages in this area Columbia has added four damage prevention coordinators to expand contractor outreach efforts. With the addition of the damage prevention coordinators, Columbia experienced a downward trend in Contractor negligence for 2015.

- During the winter of 2014-2015, failures were experienced with field assembled risers and have been identified as a DIMP risk. Columbia is developing a program to address the risk of field assembled riser failures. The program will included a survey of customer-owned and company-owned service lines to identify and quantify field assembled risers in use. Columbia will use the collected data to further asses DIMP risk and prioritize efforts. Columbia has begun replacing field assembled risers identified on company-owned service lines.

The pipeline safety DIMP Plan accelerated action enhancement items identified above, in conjunction with the Company's ongoing bare steel, cast iron, and wrought iron accelerated replacement program, are designed to address the key risks identified in Columbia's DIMP Plan, and continue to reduce the inherent pipeline safety risks in Columbia's operating system.

Q. Are there any additional details demonstrating the improvement of Columbia's system operations?

A. Some of the results from DIMP driven practice enhancements or procedural changes, which improve Columbia's system include:

- Columbia reduced the number of open Type-2 leaks in the Columbia distribution system as measured by the annual Federal DOT report. It is worth noting that corrosion on bare steel is identified as a high level DIMP Plan risk in the Columbia system, and that roughly 75% of Type-2 leaks in the system are caused by corrosion on bare steel. Further, this is a significant undertaking in assuring safe and reliable service to customers, as the greater the number of leaks in a system and the longer they are left unattended, the greater the potential risk of gas migrating into a structure or other underground facility. The result of this focused effort was that at the end of 2007 (the first full year of Columbia's annual system wide bare steel survey), Columbia reported a total of 3,755 open Type-2 leaks in its Distribution System. As of December 31, 2015, Columbia had reduced that number to 950 open Type-2 leaks, which equates to a nearly 75% reduction in open Type-2 leaks over the last eight years. In addition, as indicated in our DIMP Plan, Columbia intends to continue initiatives to accelerate its Type-2 leak repairs in order to further reduce the number of open Type-2 leaks.

- Columbia improved its locating performance as measured by third-party damage per thousand locates. This operational safety metric is particularly critical, as third-party damage is the leading cause of federally reportable pipeline incidents (e.g. Death, Injury requiring hospitalization, or Property Damage over $50,000) in the United States. In addition, failure to locate facilities is a high level risk identified in Columbia's DIMP Plan. Since 2006, Columbia has undertaken a comprehensive process designed to improve locating performance and reduce third-party damage to Company facilities. This process includes tighter management and more stringent performance standards for locators, and resulted in a pilot program initiated in 2009 to bring the locating function back in-house for two large operating centers in Pennsylvania. In early 2012, Columbia decided to bring all locating back in-house. The Company made this decision because the data from the pilot program consistently showed that in-house locators delivered better third-party damage results than those of any of the contract locators who performed this work for Columbia. Combined with improved techniques to locate difficult to locate facilities, locator error has significantly improved over time. Locator error in 2010, as a percent of damages, was 16.62% compared to the 2015 performance of 11%.

  Columbia continues to routinely conduct face-to-face meetings with excavators who are frequent damagers and has added resources to accelerate this activity. Damage prevention coordinators educate contractor employees in safe excavating practices and the coordinators remind contractors of the potential consequences of damaging natural gas facilities. These efforts have resulted in a 44.7% reduction in third-party damage on the Columbia system between 2007 and 2015, from a damage per thousand (locate requests) rate of 5.39 in 2007 to a damage per thousand rate of 2.41 through December 31, 2015.

- Columbia began a cross bore program in September of 2013, as a result of identifying cross bores as a potential risk in its DIMP plan. Working with local municipalities, Columbia inspected over 122 miles of sanitary and sewer mains, and 9,991 customer laterals since 2013. During this inspection, 185 cross bores were identified, with 120 of those involving Columbia's system. Each of the identified cross bores was replaced. Given program results, cross bores have moved from a potential risk to a high risk in Columbia's DIMP plan. The cross bore program is an example of how DIMP is used to identify and mitigate system risk.

VI. <u>Columbia's Operating Performance</u>

Q. In addition to Columbia's intense focus on pipeline safety, what are some of the practice enhancements or procedural changes regarding operating performance that are specific to customer delivery performance?

A. Columbia initiated the following customer service delivery improvements over the last five years:

- Columbia recently initiated a number of customer service improvement efforts. These efforts include piloting a two hour appointment window, implementing a customer ambassador program, and an increased focus on customer communications. Columbia's efforts, combined with improved customer service options resulted in a more positive customer experience. In 2015, Columbia received an award from JD Power for ranking first in customer satisfaction among all midsize utilities in the east region. This award reflects customer recognition of the system improvements made on their behalf.
- Columbia implemented 60-minute or less Emergency Response Rates. Emergency response rates are integral to public safety. The sooner the first Columbia responder arrives at a possible emergency, the quicker the situation can be stabilized, made safe, and ultimately remediated. Since 2006, Columbia has implemented a very structured approach to improving its emergency response times, including the addition of field operations positions, additional off hours shifts, the use of GPS technology to enable dispatching the closest/quickest responder to emergencies, and instructing all employees to focus on responding to reported emergencies as quickly and as safely as possible. In addition, Columbia continues to make

enhancements in an effort to keep emergency response rates down. Starting in 2011, Columbia implemented an automated crew call out and resource management system to call the service technician located closest to an issue that requires a response after hours. Columbia also negotiated additional language to our labor contracts which requires a service technician to be on Emergency Responder Rotation so that we have an initial responder available 24 hours a day, 365 days a year. The results of these focused efforts have resulted in improved performance. A comparison of the data showing the 60-minute or less response rates from 2007 to 2015 is as follows:

	2006	**2015**
➢ Normal Hours	98.13%	99.64%
➢ After Hours	92.34%	97.42%
➢ Weekends & Holidays	88.99%	97.24%
➢ Total Performance	97.00%	98.53%

- Columbia achieved an increase in the number of Columbia's on-time customer appointments, as measured by the overall annual percentage of on-time appointments met. As more and more customers need to take time off from work to provide access to their homes for routine meter turn-on, turn-off, and other service related activities, it is incumbent upon the Company to be as efficient as possible with the customers' time. Therefore, in 2007, Columbia began to focus specific attention on improving its percentage of on-time appointments. It did so by tasking the Integration Center (Columbia's Centralized Scheduling and Dispatch Center) with improving field employees' daily schedules to align more closely with the needs of customer appointments, and to shift non-emergency work, when possible, to meet appointments that, for a variety of reasons, might otherwise be missed. As a result of these efforts, Columbia has been able to improve its on-time appointment rates from 97% in 2007, to a rate of 98.23% in 2015.

Q. Please describe the Company's reduction in OSHA recordable injuries.

A. Columbia continues to enhance its culture of safety for customers, communities, and employees. Employee safety has significantly improved and has achieved top decile performance in OSHA Recordable Injuries, as measured by AGA benchmarking, for the second year. For comparison, at the end of 2006, Columbia had 48 Occupational Safety and Health Administration ("OSHA") recordable injuries, and in 2015 that number was only 15 OSHA recordable injuries. Columbia has previously received industry awards from both the American Gas Association and the Energy Association of Pennsylvania in recognition of its industry leading performance. Our goal is for every employee to go home safe and healthy every day. Columbia achieved this performance through multiple, cultural building efforts, such as:

- In 2014, Columbia implemented Safety Telematics across its operations. This program provides real time feedback to drivers on their driving performance. It also provides detailed reporting to enable analysis of driving trends and habits providing actionable information to improve driver safety.
- Columbia created local and state-wide safety teams made up of engaged front line workers, leaders, and managers. These teams make recommendations on, and implement, safety improvement opportunities.
- Columbia undertakes a root cause analysis of every OSHA recordable injury and preventable vehicle accident that involves a Columbia employee. Near miss discussions are also conducted.
- Columbia delivers safety training to all employees. This training spans skills from driving maneuverability to office ergonomics.
- Columbia conducts an employee safety audit program in which leaders perform safety audits on field activities, and provide feedback to employees' on their safety performance.
- Columbia employees evaluate the hazards at each jobsite prior to beginning work and complete a safety check list which is reviewed with each employee.

Q. Regarding Columbia's operating performance, does the Company meet or exceed state and federal requirements for leak surveying?

A. Yes, in 2007, Columbia began an accelerated leakage survey program to inspect all bare steel mains annually, instead of the three-year interval which is required in the leakage survey requirements of CFR 49, Part 192. As a result, Columbia routinely exceeds the requirements of existing Federal Regulations, which provides the Company the ability to discover system leakage on a more timely basis than if it were only meeting the minimum federal standards.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Statement No. 8

COLUMBIA GAS OF PENNSYLVANIA, INC.

Direct Testimony

of

Paul R. Moul, Managing Consultant
P. Moul & Associates

Concerning

Cost of Equity and
Fair Rate of Return

DOCKET NO. R-2016-2529660

March 18, 2016

<u>Columbia Gas of Pennsylvania, Inc.</u>
Direct Testimony of Paul R. Moul
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GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
AFUDC	Allowance for Funds Used During Construction
β	Beta
b	Represents the retention rate that consists of the fraction of earnings that are not paid out as dividends
b x r	Represents internal growth
CAPM	Capital Asset Pricing Model
CCR	Corporate Credit Rating
CE	Comparable Earnings
CPA	Columbia Gas of Pennsylvania, Inc.
DCF	Discounted Cash Flow
FOMC	Federal Open Market Committee
FFRY	Fully Forecasted Rate Year
g	Growth rate
IGF	Internally Generated Funds
LDC	Local Distribution Companies
Lev	Leverage modification
LIBOR	London Interbank Offered Rate
LT	Long Term
M&M	Modigliani & Miller
P-E	Price-earnings
PPUC	Pennsylvania Public Utility Commission
PUHCA	Public Utility Holding Company Act of 2005
r	Represents the expected rate of return on common equity
Rf	Risk-free rate of return
Rm	Market risk premium
RP	Risk Premium
s	Represents the new common shares expected to be issued by a firm
SBBI	Stocks, Bonds, Bills and Inflation

GLOSSARY OF ACRONYMS AND DEFINED TERMS	
ACRONYM	**DEFINED TERM**
s x v	Represents external growth
S&P	Standard & Poor's
v	Represents the value that accrues to existing shareholders from selling stock at a price different from book value
WNA	Weather Normalization Adjustment Mechanism

INTRODUCTION AND SUMMARY OF RECOMMENDATIONS

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

A. My name is Paul Ronald Moul. My business address is 251 Hopkins Road, Haddonfield, New Jersey 08033-3062. I am Managing Consultant at the firm P. Moul & Associates, an independent financial and regulatory consulting firm. My educational background, business experience and qualifications are provided in Appendix A, which follows my direct testimony.

Q. What is the purpose of your direct testimony?

A. My testimony presents evidence, analysis, and a recommendation concerning the appropriate cost of common equity and overall rate of return that the Pennsylvania Public Utility Commission ("PPUC" or the "Commission") should recognize in the determination of the revenues that Columbia Gas of Pennsylvania, Inc. ("CPA" or the "Company") should realize as a result of this proceeding. My analysis and recommendation are supported by the detailed financial data contained in Exhibit No. 400, which is a multi-page document divided into fourteen (14) schedules.

Q. Based upon your analysis, what is your conclusion concerning the appropriate rate of return for the Company in this case?

A. Based upon my analysis of the Company and the superior performance of its management, as described in the testimony of Mr. Mark Kempic, President of the Company (Columbia Statement No. 1), it is my opinion that the rate of return on common equity should be set at 11.00%. As shown on page 1 of Schedule 1, I have presented the weighted average cost of capital for the Company, which is calculated with the December 31, 2017 Fully Forecasted Rate Year ("FFRY"). The Company's proposed rate of return is shown below:

Type of Capital	Ratios	Cost Rate	Weighted Cost Rate
Long-Term Debt	43.91%	5.26%	2.31%
Short-Term Debt	3.78%	2.33%	0.09%
Total Debt	47.69%		2.40%
Common Equity	52.31%	11.00%	5.75%
Total	100.00%		8.15%

The resulting overall cost of capital, which is the product of weighting the individual capital costs by the proportion of each respective type of capital, should establish a compensatory level of return for the use of capital and, if achieved, will provide the Company with the ability to attract capital on reasonable terms.

Q. What background information have you considered in reaching a conclusion concerning the Company's cost of capital?

A. The Company is a wholly-owned subsidiary of NiSource Gas Distribution Group, which is a wholly-owned subsidiary of NiSource Inc. ("NiSource"). NiSource is a holding company under the Public Utility Holding Company Act of 2005 ("PUHCA") and also owns Northern Indiana Public Service Company (a combination gas and electric utility), Bay State Gas Company, d/b/a Columbia Gas of Massachusetts, and other energy investments.

The Company provides natural gas distribution service to approximately 422,000 customers located in south-central and western Pennsylvania. Throughput to its customers for the twelve-months ended December 31, 2014 was represented by approximately 43% to sales customers and approximately 57% to transportation customers. CPA obtains its gas supplies from producers and marketers and has transportation arrangements through connections with six interstate pipelines. The Company has storage arrangements with three suppliers to supplement flowing gas.

Q. How have you determined the cost of common equity in this case?

A. The cost of common equity is established using capital market and financial data relied upon by investors to assess the relative risk, and hence the cost of equity, for a gas distribution utility, such as the Company. In this regard, I have considered four (4) well-recognized models. These methods include: the Discounted Cash Flow ("DCF") model, the Risk Premium ("RP") analysis, the Capital Asset Pricing Model ("CAPM"), and the Comparable Earnings ("CE") approach. The results of a variety of approaches indicate that the Company's rate of return on common equity is 11.00%.

Q. In your opinion, what factors should the Commission consider when determining the Company's cost of capital in this proceeding?

A. The Commission's rate of return allowance must be set to cover the Company's interest and dividend payments, provide a reasonable level of earnings retention, produce an adequate level of internally generated funds to meet capital requirements, be commensurate with the risk to which the Company's capital is exposed, assure confidence in the financial integrity of the Company, support reasonable credit quality, and allow the Company to raise capital on reasonable terms. The return that I propose fulfills these established standards of a fair rate of return set forth by the landmark Bluefield and Hope cases.[1] That is to say, my proposed rate of return is commensurate with returns available on investments having corresponding risks.

Q. How have you measured the cost of equity in this case?

A. The models that I used to measure the cost of common equity for the Company were applied with market and financial data developed from a group of eight (8) gas

[1] Bluefield Water Works & Improvement Co. v. P.S.C. of West Virginia, 262 U.S. 679 (1923) and F.P.C. v. Hope Natural Gas Co., 320 U.S. 591 (1944).

companies. The companies are identified on page 2 of Schedule 3. I will refer to these companies as the "Gas Group" throughout my testimony.

Q. Please explain the selection process used to assemble the Gas Group?

A. I began with all of the gas utilities contained in The Value Line Investment Survey, which consists of twelve companies. Value Line is an investment advisory service that is a widely used source in public utility rate cases. Through the application of my screening process, I eliminated four companies. Two companies were eliminated because they are the targets of acquisitions. Two others were also removed. The individual eliminations were: AGL Resources due to the announced acquisition of it by Southern Company, NiSource Inc. due to its sizable electric operations and recent separation of the former natural gas pipeline/storage operations, Piedmont Natural Gas due to the announced acquisition of it by Duke Energy Corp., and UGI Corp. due to its diversified businesses consisting of six reportable segments, including propane, two international LPG segments, natural gas utility, energy services, and electric generation. The eliminations were attributed to operational differences and diversification, as identified in page 2 of Schedule 3. The remaining eight companies are included in my Gas Group.

Q. How have you performed your cost of equity analysis with the market data for the Gas Group?

A. I have applied the models/methods for estimating the cost of equity using the average data for the Gas Group. I have not measured separately the cost of equity for the individual companies within the Gas Group, because the determination of the cost of equity for an individual company can be problematic. The use of group average data will reduce the effect of potentially anomalous results for an individual company if a company-by-company approach were utilized.

Q. Please summarize your cost of equity analysis.

A. My cost of equity determination was derived from the results of the methods/models identified above. In general, the use of more than one method provides a superior foundation to arrive at the cost of equity. At any point in time, a single method can provide an incomplete measure of the cost of equity. The specific application of these methods/models will be described later in my testimony. The following table provides a summary of the indicated costs of equity using each of these approaches.

DCF	10.79%
Risk Premium	11.90%
CAPM	11.16%
Comparable Earnings	12.80%

As I will discuss later, CPA has more risk than the Gas Group attributed to its weaker credit quality, its smaller size, and other factors. To the extent that these higher risk factors can be quantified, they are reflected in the results shown above. From these measures, I recommend a cost of equity of 11.00% with recognition of the exemplary performance of the Company's management. Mr. Kempic has shown that the Company ranks high in customer service and management efficiency. In recognition of its outstanding performance, the Company should be granted an opportunity to earn an 11.00% rate of return on common equity. The 11.00% rate of return on common equity, which includes 25 basis points for recognition of the exemplary performance of the Company's management, is well with the range of the market-based measures (i.e., DCF, RP and CAPM) of the cost of equity that range from 10.79% to 11.90% (the results of the Comparable Earnings method is higher). To obtain new capital and retain existing capital, the rate of return on common equity must be high enough to satisfy investors' requirements.

NATURAL GAS RISK FACTORS

Q. What factors currently affect the business risk of natural gas utilities?

A. Gas utilities face risks arising from competition, economic regulation, the business cycle, and customer usage patterns. Today, they operate in a more complex environment with time frames for decision-making considerably shortened. Their business profile is influenced by market-oriented pricing for the commodity distributed to customers and open access for the transportation of natural gas for customers.

Natural gas utilities have focused increased attention on safety and reliability issues and on conservation. In order to address these issues and to comply with new and pending pipeline safety regulations, natural gas companies are now allocating more of their resources to addressing aging infrastructure issues. The testimony of Mr. Kempic and other Company witnesses discuss the investments that the Company will make to address these issues.

The Company also faces a series of risks that impact its cost of equity. In the western area of Pennsylvania, the Company operates in a unique situation with overlapping service territories, which enable other gas utilities to compete with one another for customers. Further, there are six interstate pipelines that traverse the Company's service territory. This situation exposes the Company to bypass for certain large volume customers. Finally, the existence of local gas production provides a bypass threat to the Company. This situation will only become more intense with increasing production from the Marcellus Shale formation. In addition, with the consolidation of several formerly competing LDCs in western Pennsylvania, CPA could potentially face additional threats from the stronger LDC competitor that remains. Overall, the Company's risk of competition is considerably higher than that faced by many LDCs, including the members of the Gas Group that I used to measure the Company's cost of equity.

Q. Are there other features of the Company's business that should be considered when assessing the Company's risk?

A. Yes. Most of the Company's residential and commercial customers use natural gas for space heating purposes. This indicates that a large proportion of the Company's residential and commercial customers present a low load factor profile and their energy demands are significantly influenced by temperature conditions, over which the Company has absolutely no control. To deal with this issue, CPA has a weather normalization adjustment mechanism ("WNA") as part of its tariff. The WNA is applicable only to residential customers, and has a 5% deadband. This means that the Company's revenues continue to be subject to variation due to weather, albeit less than formerly. I am advised that in the first year of operation, the Company refunded approximately $9.36 million to customers under the WNA. In the second year, the Company refunded approximately $10.98 million to customers under the WNA. In total, the Company has refunded over $20 million to customers under its WNA pilot program. This tariff provision will function as a pilot program that continues until the conclusion of Columbia's next base rate case following this rate case.

Q. Does your cost of equity analysis and recommendation take into account the WNA rate design that the Company is using?

A. Yes. The Company operates with a WNA tariff provision on a pilot basis. All but two companies in my Gas Group have some form of WNA mechanism. Even these two companies have or are proposing to adopt mechanisms that account for the effect of weather. In the case of Laclede Gas, it has a weather mitigated rate design that recovers its fixed costs more evenly during the heating season. In the case of

Chesapeake, it is currently seeking to implement a decoupling mechanism in the Delaware division tariff. Therefore, the market prices of the companies in my Gas Group reflect the expectations of investors that these companies' revenues are stabilized to some extent by a WNA mechanism. Therefore, my analysis reflects the impacts of WNA on investor expectations through the use of market-determined models. If the Company is unable to continue with its WNA rate design beyond 2016, its risk will increase above that of the Gas Group that serves as a basis to measure the Company's cost of equity, i.e., the Gas Group's cost of equity will then understate the return that is appropriate for the Company.

Q. Are you aware that there is a DSIC available to natural gas and electric utilities in Pennsylvania, and does the DSIC affect the Company's cost of capital?

A. I am aware that the Company had utilized the DSIC for a short period of time in the past, and that Columbia is seeking an increase in the DSIC rate cap in order to make the DSIC a viable option in the future. The cost of capital for CPA, however, is not be affected by the DSIC. I say this because most of the proxy group companies (i.e., five of eight companies) whose data has been used to develop the cost of equity for CPA in this proceeding have a DSIC or similar infrastructure rehabilitation mechanisms. Indeed, Atmos Energy, Laclede Group, New Jersey Resources, Northwest Natural Gas, and South Jersey Industries make use of a DSIC or similar infrastructure rehabilitation mechanisms. Hence, whatever the benefit of a DSIC, or other regulatory mechanisms, that impact is already reflected in the market evidence of the cost of equity for the proxy group.

Q. How does the Company's throughput to large volume users or those with competitive alternatives affect its risk profile?

A. The Company's risk profile is influenced by natural gas delivered to its large industrial and commercial customers and those customers with competitive alternatives, as demonstrated by the fact that gas throughput to the Company's 158 major account customers represents approximately 29% of the Company's total throughput. In addition, the ten largest customers by volume represent approximately 9.4 million Dth of throughput during the twelve months ended November 30, 2015. Generally speaking, there are four primary threats to throughput to the Company's largest volume users. First, the Company can and has experienced attrition in this large customer group. Second, the Company's largest customers, which have traditionally used transportation service, have the ability to bypass the Company's system to other gas supply sources such as interstate pipelines, other local distribution companies, or nonregulated pipeline contractors providing access to local supplies. In this regard, the Company has identified 17.5 million Dth per year of customer throughput that is susceptible to such bypass. Of course the number that CPA has identified is only a subset of the total load at risk since it is almost certain that the Company has not identified all customers who have competitive alternatives. Third, in addition to the bypass threat, a material portion of the large customer throughput can be exposed to fuel switching to coal, oil, propane, or other energy sources depending on the fluctuating costs of these different fuels in comparison with natural gas. Finally, in its effort to retain load, the Company is vulnerable to the impacts of business cycles, competition within its customers' industries, and other external factors that can result in shifts of production to customer facilities that are not served by the Company. All of these risks put fixed cost recovery for this class of customers at risk.

Q. Please indicate how the Company's construction program affects its risk profile.

A. The Company is faced with the requirement to undertake investments to maintain and upgrade existing facilities in its service territory. To maintain safe and reliable service to existing customers, the Company must invest to upgrade its infrastructure. The rehabilitation of the Company's infrastructure represents capital expenditures that do not increase the Company's customer base. Although the Company has made significant strides in reducing its percentage of cast iron and unprotected steel pipe, these facilities still represent 1,631.9 miles (or approximately 22%) of its distribution mains as of year-end 2014. The Company also has 56,766 (or approximately 13%) of its services constructed of unprotected steel. For the future, the Company expects its net capital expenditures to be:

Year	Capital Expenditures
2016	$ 223,539
2017	$ 264,526
2018	$ 266,051
2019	$ 259,857
2020	$ 207,109
Total	$ 1,221,082

The Company's total capital expenditures over the next five years will represent approximately 84% ($1,221,082 ÷ $1,450,365) of the net utility plant in service at December 31, 2015.

Q. How should the Commission respond to the issues facing the natural gas utilities and in particular CPA?

A. The Commission should recognize and take into account the need to replace infrastructure and the competitive environment in the natural gas business in determining the cost of capital for the Company, and provide a reasonable opportunity for the Company to actually achieve its cost of capital. A fair rate of return also represents a key to a financial profile that will provide the Company with the ability to raise the significant amount of capital necessary to meet its capital needs on reasonable terms. The Company has been proactive in dealing with its capital requirements for infrastructure needs by not making any dividend payments for 2014 and 2015. By foregoing dividend payments, the Company is committed to reinvestment in Pennsylvania. The Commission should recognize and reward this commitment with a reasonable return on equity.

FUNDAMENTAL RISK ANALYSIS

Q. Is it necessary to conduct a fundamental risk analysis to provide a framework for a determination of a utility's cost of equity?

A. Yes, it is. It is necessary to establish a company's relative risk position within its industry through a fundamental analysis of various quantitative and qualitative factors that bear upon investors' assessment of overall risk. The qualitative factors that bear upon Company risk have already been discussed previously. The quantitative risk analysis follows. The items that influence investors' evaluation of risk and their required returns were described above. For this purpose, I compared the Company to the S&P Public Utilities, an industry-wide proxy consisting of various regulated businesses, and to the Gas Group.

Q. What are the components of the S&P Public Utilities?

A. The S&P Public Utilities is a widely recognized index that is comprised of electric power and natural gas companies. These companies are identified on page 3 of Schedule 4.

Q. What companies comprise the gas group?

A. My Gas Group consists of the following companies: Atmos Energy Corp., Chesapeake Utilities Corporation, Laclede Group, Inc., New Jersey Resources Corp., Northwest Natural Gas Co., South Jersey Industries, Inc., Southwest Gas Corporation, and WGL Holdings, Inc.

Q. Is knowledge of a utility's bond rating an important factor in assessing its risk and cost of capital?

A. Yes. Knowledge of a company's credit quality rating is important because the cost of each type of capital is directly related to the associated risk of the firm. So while a company's credit quality risk is shown directly by the rating and yield on its bonds, these relative risk assessments also bear upon the cost of equity. This is because a firm's cost of equity is represented by its borrowing cost plus compensation to recognize the higher risk of an equity investment compared to debt.

Q. How do the credit quality ratings compare for the Company, the Gas Group, and the S&P Public Utilities?

A. The Company obtains its external capital not funded by internal sources from NiSource Finance Corp. Presently, the NiSource credit quality ratings are Baa2 from Moody's Investors Service ("Moody's") and BBB+ from Standard & Poor's Corporation ("S&P"). These ratings for NiSource represent the Long Term ("LT") issuer rating by Moody's and the corporate credit rating ("CCR") designation by S&P, which focuses upon the credit quality of the issuer of the debt rather than upon the debt obligation itself.

For the Gas Group, the average LT issuer rating is A2 by Moody's and the average CCR is A- by S&P, as displayed on page 2 of Schedule 3. For the S&P Public Utilities, the average credit quality rating is A3 by Moody's and BBB+ by S&P, as displayed on page 3 of Schedule 4. Many of the financial indicators that I will subsequently discuss are considered during the rating process.

Q. How do the financial data compare for the Company, the Gas Group, and the S&P Public Utilities?

A. The broad categories of financial data that I will discuss are shown on Schedules 2, 3, and 4. The data cover the five-year period 2010-2014. The important categories of relative risk may be summarized as follows:

Size. In terms of capitalization, the Company is smaller than the average size of the Gas Group, and smaller still than the average size of the S&P Public Utilities. All other things being equal, a smaller company is riskier than a larger company because a given change in revenue and expense has a proportionately greater impact on a small firm. As I will demonstrate later, the size of a firm can impact its cost of equity.

Market Ratios. Market-based financial ratios, such as earnings/price ratios and dividend yields, provide a partial measure of the investor-required cost of equity. If all other factors are equal, investors will require a higher rate of return for companies that exhibit greater risk, in order to compensate for that risk. That is to say, a firm that investors perceive to have higher risks will experience a lower price per share in relation to expected earnings.[2]

There are no market ratios available for the Company because its stock is owned by NiSource. The five-year average price-earnings multiple was similar for the Gas Group and to the S&P Public Utilities. The five-year average dividend yield was lower for the Gas Group as compared to the S&P Public Utilities. The five-year average market-to-book ratio was somewhat higher for the Gas Group as compared to the S&P Public Utilities.

Common Equity Ratio. The level of financial risk is measured by the proportion of long-term debt and other senior capital that is contained in a company's

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[2]For example, two otherwise similarly situated firms each reporting $1.00 in earnings per share would have different market prices at varying levels of risk (i.e., the firm with a higher level of risk will have a lower share value, while the firm with a lower risk profile will have a higher share value).

capitalization. Financial risk is also analyzed by comparing common equity ratios (the complement of the ratio of debt and other senior capital). That is to say, a firm with a high common equity ratio has lower financial risk, while a firm with a low common equity ratio has higher financial risk. The five-year average common equity ratios, based on permanent capital, were 55.8% for CPA, 57.6% for the Gas Group, and 45.3% for the S&P Public Utilities. The common equity ratios were similar for CPA and the Gas Group, thereby indicating similar financial risk.

Return on Book Equity. Greater variability (i.e., uncertainty) of a firm's earned returns signifies relatively greater levels of risk, as shown by the coefficient of variation (standard deviation ÷ mean) of the rate of return on book common equity. The higher the coefficients of variation, the greater degree of variability. For the five-year period, the coefficients of variation were 0.111 (1.4% ÷ 12.6%) for the Company, 0.058 (0.6% ÷ 10.4%) for the Gas Group, and 0.102 (1.0% ÷ 9.8%) for the S&P Public Utilities. The variability of the Company's rates of return was higher than the Gas Group and the S&P Public Utilities, thereby signifying higher risk for the Company.

Operating Ratios. I have also compared operating ratios (the percentage of revenues consumed by operating expense, depreciation, and taxes other than income).[3] The five-year average operating ratios were 84.6% for the Company, 88.3% for the Gas Group, and 81.3% for the S&P Public Utilities. The Company's operating ratios were somewhat lower than the Gas Group, thereby indicating lower risk.

Coverage. The level of fixed charge coverage (i.e., the multiple by which available earnings cover fixed charges, such as interest expense) provides an

[3]The complement of the operating ratio is the operating margin which provides a measure of profitability. The higher the operating ratio, the lower the operating margin.

indication of the earnings protection for creditors. Higher levels of coverage, and hence earnings protection for fixed charges, are usually associated with superior grades of creditworthiness. Excluding Allowance for Funds Used During Construction ("AFUDC"), the five-year average pre-tax interest coverage was 3.85 times for the Company, 4.90 times for the Gas Group, and 3.19 times for the S&P Public Utilities. The average interest coverages were highest for the Gas Group, followed by CPA and the S&P Public Utilities. As compared to the Gas Group, the Company has higher credit risk.

Quality of Earnings. Measures of earnings quality usually are revealed by the percentage of AFUDC related to income available for common equity, the effective income tax rate, and other cost deferrals. These measures of earnings quality usually influence a firm's internally generated funds because poor quality of earnings would not generate high levels of cash flow. Quality of earnings has not been a significant concern for the Company, the Gas Group and the S&P Public Utilities.

Internally Generated Funds. Internally generated funds ("IGF") provide an important source of new investment capital for a utility and represent a key measure of credit strength. Historically, the five-year average percentage of IGF to capital expenditures was 60.1% for the Company, 90.0% for the Gas Group and 87.5% for the S&P Public Utilities. The Company's average IGF to construction percentage has lagged that of the Gas Group, thereby signifying higher risk created by the greater need to raise capital externally. Had the Company paid dividends in recent years, its IGF would have been even weaker.

Betas. The financial data that I have been discussing relate primarily to company-specific risks. Market risk for firms with publicly-traded stock is measured by beta coefficients. Beta coefficients attempt to identify systematic risk, i.e., the risk associated with changes in the overall market for common equities.[4] Value Line publishes such a statistical measure of a stock's relative historical volatility to the rest of the market. A comparison of market risk is shown by the Value Line beta of 0.74 as the average for the Gas Group (see page 2 of Schedule 3) and 0.77 as the average for the S&P Public Utilities (see page 3 of Schedule 4).

Q. Please summarize your risk evaluation.

A. In several aspects, principally related to its smaller size, its more variable equity returns, its lower interest coverage, its lower IGF to construction, competition pressures, and new capital needs to fund construction, CPA's risk is higher than the Gas Group. The bond rating of NiSource, the Company's ultimate parent, is below that of the Gas Group, which indicates higher credit quality risk. Its common equity ratio and quality of earnings has been fairly similar to the Gas Group. CPA's operating ratio has been lower revealing less risk. On balance, the cost of equity measured with the Gas Group data will provide an understatement of the Company's cost of equity.

CAPITAL STRUCTURE RATIOS

Q. Please explain the selection of capital structure ratios for CPA.

A. In this case, the capital structure ratios of CPA have been proposed to calculate the rate of return. I will show that the Company's capital structure ratios proposed in this case are reasonable. Furthermore, consistency requires that the embedded cost rate of the Company's senior securities also be employed.

[4]Beta is a relative measure of the historical sensitivity of the stock's price to overall fluctuations in the New York Stock Exchange Composite Index. The "Beta coefficient" is derived from a regression analysis of the relationship between weekly percentage changes in the price of a stock and weekly percentage changes in the NYSE Index over a period of five years. The betas are adjusted for their long-term tendency to converge toward 1.00. A common stock that has a beta less than 1.0 is considered to have less systematic risk than the market as a whole and would be expected to rise and fall more slowly than the rest of the market. A stock with a beta above 1.0 would have more systematic risk.

Q. Does Schedule 5 provide the Company's capitalization and capital structure ratios?

A. Yes. Schedule 5 presents the Company's capitalization and related capital structure ratios. The November 30, 2015 capitalization corresponds with the end of the historic test year in this case. The November 30, 2016 capital structure is estimated at the end of the future test year, and the December 31, 2017 capital structure is estimated at the end of the fully forecasted rate year. Prior to the end of the fully forecasted rate year, the Company plans to issue $130 million of new long-term debt, a portion of which will be used to redeem at maturity $18.525 million of long-term debt. Of these amounts, $45 million will be issued in March 2016. The maturity will occur in November 2016. An additional new debt issue will occur in January 2017. Pursuant to Paragraph 26 of the approved settlement in Columbia's 2014 base rate case (Docket No. R-2014-2406274), I am including, as Exhibit PRM-1 to my testimony, the methodology used for the pricing of the Company's most recent debt issue in September 2015. Supporting data includes the Treasury Yield as reported in the Federal Reserve Statistical Release, H. 15 Selected Interest Rates and the yield spread as reported by Bloomberg. Exhibit PRM-1 describes the new procedure that was adopted for the pricing of this issue and for debt issuances going forward that was caused by a change in the availability of certain interest rate data.

Q. How do the capital structure ratios compare for CPA and the Gas Group?

A. I have verified the reasonableness of the Company's common equity ratio by considering the historical comparison to the Gas Group. For the historical comparison, the Gas Group had a 54.9% common equity ratio at year-end 2014 calculated without short-term debt. Over the past five years, the average common equity ratio for the Gas Group has been 54.9% to 59.1%. My comparison of these ratios rests on a calculation without short-term debt because the Company uses a twelve-month average for ratesetting purposes, while the GAAP financial reports for the Gas Group use fiscal year-end balances of short-term debt. For the Company, its FFRY common equity ratio is 54.4% ($745,229,000 ÷ $1,370,744,000) computed without short-term debt, thereby indicating that the Company's common equity ratio is reasonable.

Q. What capital structure ratios do you recommend be adopted for rate of return purposes in this proceeding?

A. Since ratesetting is prospective, the rate of return should, at a minimum, reflect known or reasonably foreseeable changes which will occur during the course of the fully forecasted rate year. As a result, I will adopt the Company's fully forecast rate year capital structure ratios of 43.91% long-term debt, 3.78% short-term debt, and 52.31% common equity at December 31, 2017. For short-term debt, I have used a twelve-month average for the fully forecasted rate year. These capital structure ratios are the best approximation of the mix of capital the Company will employ to finance its rate base during the period new rates are in effect.

<u>COSTS OF SENIOR CAPITAL</u>

Q. What cost rate have you assigned to the debt portion of CPA's capital structure?

A. The determination of the long-term debt cost rate is essentially an arithmetic exercise. This is due to the fact that the Company has contracted for the use of this capital for a specific period of time at a specified cost rate. As shown on page 1 of Schedule 6, I have computed the actual embedded cost rate of debt at November 30, 2015. On page 2 of Schedule 6, I have shown the estimated embedded cost rate of debt at November 30, 2016. And on page 3 of Schedule 6, the embedded cost of debt is shown at December 31, 2017. For the new issues of long-term debt, I have used a cost of 4.53% for the issue in March 2016 and 4.58% for the issue in January 2017. These rates compare to the 4.505% that the Company paid to obtain debt in September 2015.

I will adopt the 5.26% embedded cost of long-term debt at December 31, 2017, as shown on page 3 of Schedule 6. This rate is related to the amount of long-term debt shown on Schedule 5 which provides the basis for the 43.91% long-term debt ratio.

Q. What cost rate have you assigned to the short-term debt?

A. I have used a cost of short-term debt of 2.33%, which represents the Company's estimate for the fully forecast rate year. The Company obtains its short-term debt from the NiSource money pool, which has a credit facility with a syndicate of banks. The interest rate is established as the one-month LIBOR plus 107.5 basis points. Hence, the Company's estimate is comprised of the 1.255% LIBOR plus the spread, i.e., 1.255% + 1.075% = 2.330%.

Q. What overall debt cost rate have you determined for rate of return purposes?

A. As shown on page 3 of Schedule 6, the combined cost of long- and short-term debt is 5.03% for the fully forecast rate year.

COST OF EQUITY – GENERAL APPROACH

Q. Please describe the process you employed to determine the cost of equity for the Company.

A. Although my fundamental financial analysis provides the required framework to establish the risk relationships among the CPA, Gas Group, and the S&P Public Utilities, the cost of equity must be measured by standard financial models that I identified above. Differences in risk traits, such as size, business diversification, geographical diversity, regulatory policy, financial leverage, and bond ratings must be considered when analyzing the cost of equity.

It is also important to reiterate that no one method or model of the cost of equity can be applied in an isolated manner. Rather, informed judgment must be used to take into consideration the relative risk traits of the firm. It is for this reason that I have used more than one method to measure the Company's cost of equity. As I describe below, each of the methods used to measure the cost of equity contains certain incomplete and/or overly restrictive assumptions and constraints that are not optimal. Therefore, I favor considering the results from a variety of methods. In this regard, I applied each of the methods with data taken from the Gas Group and arrived at a cost of equity of 11.00% for the Company.

DISCOUNTED CASH FLOW

Q. Please describe your use of the Discounted Cash Flow approach to determine the cost of equity.

A. The DCF model seeks to explain the value of an asset as the present value of future expected cash flows discounted at the appropriate risk-adjusted rate of return. In its simplest form, the DCF return on common stock consists of a current cash (dividend) yield and future price appreciation (growth) of the investment. The dividend discount equation is the familiar DCF valuation model and assumes future dividends are systematically related to one another by a constant growth rate. The DCF formula is derived from the standard valuation model: $P = D/(k-g)$, where P = price, D = dividend, k = the cost of equity, and g = growth in cash flows. By rearranging the terms, we obtain the familiar DCF equation: $k= D/P + g$. All of the terms in the DCF equation represent investors' assessment of expected future cash flows that they will receive in relation to the value that they set for a share of stock (P). The DCF equation is sometimes referred to as the "Gordon" model.[5] My DCF results are provided on page 2 of Schedule 1 for the Gas Group. The DCF return is 10.79%.

Among other limitations of the model, there is a certain element of circularity in the DCF method when applied in rate cases. This is because investors' expectations for the future depend upon regulatory decisions. In turn, when regulators depend upon the DCF model to set the cost of equity, they rely upon investor expectations that include an assessment of how regulators will decide rate cases. Due to this circularity, the DCF model may not fully reflect the true risk of a utility.

Q. Please explain the dividend yield component of a DCF analysis.

A. The DCF methodology requires the use of an expected dividend yield to establish the investor-required cost of equity. For the twelve months ended December 2015, the monthly dividend yields are shown on Schedule 7 and reflect an adjustment to the month-end prices to reflect the buildup of the dividend in the price that has occurred since the last ex-dividend date (i.e., the date by which a shareholder must own the shares to be entitled to the dividend payment – usually about two to three weeks prior to the actual payment).

For the twelve months ended December 2015, the average dividend yield was 3.20% for the Gas Group based upon a calculation using annualized dividend payments and adjusted month-end stock prices. The dividend yields for the more recent six- and three-month periods were 3.21% and 3.16%, respectively. I have used, for the purpose of the DCF model, the six-month average dividend yield of 3.21% for the Gas Group. The use of this dividend yield will reflect current capital

[5] Although the popular application of the DCF model is often attributed to the work of Myron J. Gordon in the mid-1950's, J. B. Williams exposited the DCF model in its present form nearly two decades earlier.

costs, while avoiding spot yields. For the purpose of a DCF calculation, the average dividend yield must be adjusted to reflect the prospective nature of the dividend payments, i.e., the higher expected dividends for the future. Recall that the DCF is an expectational model that must reflect investor anticipated cash flows for the Gas Group. I have adjusted the six-month average dividend yield in three different, but generally accepted, manners and used the average of the three adjusted values as calculated in the lower panel of data presented on Schedule 7. This adjustment adds eleven basis points to the six-month average historical yield, thus producing the 3.32% adjusted dividend yield for the Gas Group.

Q. Please explain the underlying factors that influence investor's growth expectations.

A. As noted previously, investors are interested principally in the future growth of their investment (i.e., the price per share of the stock). Future earnings per share growth represent the DCF model's primary focus because under the constant price-earnings multiple assumption of the model, the price per share of stock will grow at the same rate as earnings per share. In conducting a growth rate analysis, a wide variety of variables can be considered when reaching a consensus of prospective growth, including: earnings, dividends, book value, and cash flow stated on a per share basis. Historical values for these variables can be considered, as well as analysts' forecasts that are widely available to investors. A fundamental growth rate analysis is sometimes represented by the internal growth ("b x r"), where "r" represents the expected rate of return on common equity and "b" is the retention rate that consists of the fraction of earnings that are not paid out as dividends. To be complete, the internal growth rate should be modified to account for sales of new common stock -- this is called external growth ("s x v"), where "s" represents the new common shares expected to be issued by a firm and "v" represents the value that accrues to existing shareholders from selling stock at a price different from book value. Fundamental growth, which combines internal and external growth, provides an explanation of the factors that cause book value per share to grow over time.

Growth also can be expressed in multiple stages. This expression of growth consists of an initial "growth" stage where a firm enjoys rapidly expanding markets, high profit margins, and abnormally high growth in earnings per share. Thereafter, a firm enters a "transition" stage where fewer technological advances and increased product saturation begin to reduce the growth rate and profit margins come under pressure. During the "transition" phase, investment opportunities begin to mature, capital requirements decline, and a firm begins to pay out a larger percentage of earnings to shareholders. Finally, the mature or "steady-state" stage is reached when a firm's earnings growth, payout ratio, and return on equity stabilizes at levels where they remain for the life of a firm. The three stages of growth assume a step-down of high initial growth to lower sustainable growth. Even if these three stages of growth can be envisioned for a firm, the third "steady-state" growth stage, which is assumed to remain fixed in perpetuity, represents an unrealistic expectation because the three stages of growth can be repeated. That is to say, the stages can be repeated where growth for a firm ramps-up and ramps-down in cycles over time.

Q. Did you assume a non-constant growth rate in your analysis?

A. No. I acknowledge that growth can also be expressed in multiple stages, but there is no need to do so in this case. As my subsequent analysis will reveal, my growth rate determination provides a constant growth rate that is sustainable given the fundamentals currently affecting the industry. For example, infrastructure rehabilitation adds to the growth of rate base that will provide the foundation for future growth that is consistent with the constant growth rate.

Q. What investor-expected growth rate is appropriate in a DCF calculation?

A. Investors consider both company-specific variables and overall market sentiment (i.e., level of inflation rates, interest rates, economic conditions, etc.) when balancing their capital gains expectations with their dividend yield requirements. I follow an approach that is not rigidly formatted because investors are not influenced by a single set of company-specific variables weighted in a formulaic manner. In my opinion, all relevant growth rate indicators using a variety of techniques must be evaluated when formulating a judgment of investor-expected growth.

Q. What company-specific data have you considered in your growth rate analysis?

A. As presented on Schedules 8 and 9, I have considered both historical and projected growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. While analysts will review all measures of growth as I have done, it is earnings per share growth that influences directly the expectations of investors for utility stocks.[6] Forecasts of earnings growth are required within the context of the DCF because the model is a forward-looking concept, and with a constant price-earnings multiple and payout ratio, all other measures of growth will mirror earnings growth. So with the assumptions underlying the DCF, all forward-looking projections should be similar with a constant price-earnings multiple, earned return, and payout ratio.

As to the issue of historical data, investors cannot purchase past earnings of a utility, rather they are only entitled to future earnings. In addition, assigning significant weight to historical performance results in double counting of the historical data. While history cannot be ignored, it is already factored into the analysts' forecasts of earnings growth. In developing a forecast of future earnings growth, an

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[6] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

analyst would first apprise himself/herself of the historical performance of a company. Hence, there is no need to count historical growth rates a second time, because historical performance is already reflected in analysts' forecasts which reflect an assessment of how the future will diverge from historical performance.

Schedule 8 shows the historical growth rates in earnings per share, dividends per share, book value per share, and cash flow per share for the Gas Group. The historical growth rates were taken from the Value Line publication that provides these data. As shown on Schedule 8, the historical growth of earnings per share was in the range of 4.25% to 5.81% for the Gas Group.

Q. What is presented in Schedule 9?

A. Schedule 9 provides projected earnings per share growth rates taken from analysts' forecasts compiled by IBES/First Call, Reuters, Zacks, Morningstar, SNL, and Value Line. IBES/First Call, Reuters, Zacks, Morningstar, and SNL represent reliable authorities of projected growth upon which investors rely. The IBES/First Call, Reuters, Zacks, and SNL growth rates are consensus forecasts taken from a survey of analysts that make projections of growth for these companies. The IBES/First Call, Reuters, Zacks, Morningstar, and SNL estimates are obtained from the Internet and are widely available to investors. First Call probably is quoted most frequently in the financial press when reporting on earnings forecasts. The Value Line forecasts also are widely available to investors and can be obtained by subscription or free-of-charge at most public and collegiate libraries. The IBES/First Call, Reuters, Zacks, and Morningstar, and SNL forecasts are limited to earnings per share growth, while Value Line makes projections of other financial variables. The Value Line forecasts of dividends per share, book value per share, and cash flow per share have also been included on Schedule 9 for the Gas Group.

Q. Is a five-year investment horizon associated with the analysts' forecasts consistent with the traditional DCF model?

A. Yes. In fact, it illustrates that the infinite form of the DCF model contains an unrealistic assumption. Rather than viewing the DCF in the context of an endless stream of growing dividends (e.g., a century of cash flows), the growth in the share value (i.e., capital appreciation, or capital gains yield) is most relevant to investors' total return expectations. Hence, the sale price of a stock can be viewed as a liquidating dividend that can be discounted along with the annual dividend receipts during the investment-holding period to arrive at the investor expected return. The growth in the price per share will equal the growth in earnings per share absent any change in price-earnings ("P-E") multiple -- a necessary assumption of the DCF. As such, my company-specific growth analysis, which focuses principally upon five-year forecasts of earnings per share growth, conforms with the type of analysis that influences the actual total return expectation of investors. Moreover, academic research focuses on five-year growth rates as they influence stock prices. Indeed, if investors really required forecasts which extended beyond five years in order to properly value common stocks, then I am sure that some investment advisory service would begin publishing that information for individual stocks in order to meet the demands of investors. The absence of such a publication is proof that investors do not require infinite forecasts in order to purchase and sell stocks in the marketplace.

Q. What does Schedule 9 show as the projected growth rates?

A. As to the five-year forecast growth rates, Schedule 9 indicates that the projected earnings per share growth rates for the Gas Group are 5.19% by IBES/First Call, 6.13% by Reuters, 5.55% by Zacks, 5.20% by Morningstar, 5.45% by SNL, and 7.00% by <u>Value Line</u>. The <u>Value Line</u> projections indicate that earnings per share for the Gas Group will grow prospectively at a more rapid rate (i.e., 7.00%) than the dividends per share (i.e., 4.88%), which translates into a declining dividend payout ratio for the future. As noted earlier, with the constant price-earnings multiple assumption of the DCF model, growth for these companies will occur at the higher earnings per share growth rate, thus producing the capital gains yield expected by investors.

Q. What conclusion have you drawn from these data regarding the applicable growth rate to be used in the DCF model?

A. A variety of factors should be examined to reach a conclusion on the DCF growth rate. However, certain growth rate variables should be emphasized when reaching a conclusion on an appropriate growth rate. From the various alternative measures of growth identified above, earnings per share should receive greatest emphasis. Earnings per share growth are the primary determinant of investors' expectations regarding their total returns in the stock market. This is because 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). Moreover, earnings per share (derived from net income) are the source of dividend payments and are the primary driver of retention growth and its surrogate, i.e., book value per share growth. As such, under these circumstances, greater emphasis must be placed upon projected earnings per share growth. In this regard, it is worthwhile to note that Professor Myron Gordon, the foremost proponent of the DCF model in rate cases, concluded that the best measure of growth in the DCF model is a forecast of earnings per share growth.[7] Hence, to follow Professor Gordon's findings, projections of earnings per share growth, such as those published by IBES/First Call,

[7] Gordon, Gordon & Gould, "Choice Among Methods of Estimating Share Yield," The Journal of Portfolio Management (Spring 1989).

Zacks, Morningstar, and Value Line, represent a reasonable assessment of investor expectations.

The forecasts of earnings per share growth, as shown on Schedule 9, provide a range of average growth rates of 5.19% to 7.00%. Although the DCF growth rates cannot be established solely with a mathematical formulation, it is my opinion that an investor-expected growth rate of 6.25% is a reasonable estimate of investor expected growth within the array of earnings per share growth rates shown by the analysts' forecasts. As I indicated above, the fundamentals for CPA, including its significant new investment in infrastructure rehabilitation, point to a higher growth rate.

Q. Are the dividend yield and growth components of the DCF adequate to explain the rate of return on common equity when it is used in the calculation of the weighted average cost of capital?

A. Only if the capital structure ratios are measured with the market value of debt and equity. In the case of the Gas Group, those average capital structure ratios are 33.06% long-term debt, 0.12% preferred stock, and 66.82% common equity, as shown on Schedule 10. If book values are used to compute the capital structure ratios, then an adjustment is required.

Q. Please explain why.

A. If regulators use the results of the DCF (which are based on the market price of the stock of the companies analyzed) to compute the weighted average cost of capital with a book value capital structure used for ratesetting purposes, those results will not reflect the higher level of financial risk associated with the book value capital structure. Where, as here, a stock's market price diverges from a utility's book value, the potential exists for a financial risk difference, because the capitalization of a utility measured at its market value contains more equity, less debt and therefore less risk than the capitalization measured at its book value.

This shortcoming of the DCF has persuaded the Commission to adjust the cost of equity upward to make the return consistent with the book value capital structure. Provisions for this risk difference were made by the Commission in the following cases:

Date	Company	Docket Number	Basis Points
January 10, 2002	Pennsylvania-American Water Co.	Docket No. R-00016339	60 basis points
August 1, 2002	Philadelphia Suburban Water Co.	Docket No. R-00016750	80 basis points
January 29, 2004	Pennsylvania-American Water Co.	Docket No. R-00038304 (affirmed by the Commonwealth Court on November 8, 2004)	60 basis points
August 5, 2004	Aqua Pennsylvania, Inc.	Docket No. R-00038805	60 basis points
December 22, 2004	PPL Electric Utilities Corp.	Docket No. R-00049255	45 basis points
February 8, 2007	PPL Gas Utilities Corp.	Docket No. R-00061398	70 basis points

In order to make the DCF results relevant to the capitalization measured at book value (as is done for ratesetting purposes) the market-derived cost rate cannot be used without modification.

Q. Please continue with your discussion of the calculation of the leverage adjustment.

A. The only perspective that is important to investors is the return that they can realize on the market value of their investment. As I have measured the DCF, the simple yield (D/P) plus growth (g) provides a return applicable strictly to the price (P) that an investor is willing to pay for a share of stock. The need for the leverage adjustment arises when the results of the DCF model (k) are to be applied to a capital structure that is different than indicated by the market price (P). From the market perspective, the financial risk of the Gas Group is accurately measured by the capital structure ratios calculated from the market capitalization of a firm. If the ratesetting process utilized the market capitalization ratios, then no additional analysis or adjustment would be required, and the simple yield (D/P) plus growth (g) components of the DCF would satisfy the financial risk associated with the market value of the equity capitalization. Because the ratesetting process uses a different set of ratios calculated from the book value capitalization, then further analysis is required to synchronize the financial risk of the book capitalization with the required return on the book value of the equity. This adjustment is developed through precise mathematical calculations, using well recognized analytical procedures that are widely accepted in the financial literature. To arrive at that return, the rate of return on common equity is the unleveraged cost of capital (or equity return at 100% equity) plus one or more terms reflecting the increase in financial risk resulting from the use of leverage in the capital structure. The calculations presented in the lower panel of data shown on Schedule 10, under the heading "M&M," provides a return of 8.30% when applicable to a capital structure with 100% common equity.

Q. Are there specific factors that influence market-to-book ratios that determine whether the leverage adjustment should be made?

A. No. The leverage adjustment is not intended, nor was it designed, to address the reasons that stock prices vary from book value. Hence, any observations concerning market prices relative to book are not on point. The leverage adjustment deals with the issue of financial risk and does not transform the DCF result to a book value return through a market-to-book adjustment. Again, the leverage adjustment that I propose is based on the fundamental financial precept that the cost of equity is equal to the rate of return for an unleveraged firm (i.e., where the overall rate of return equates to the cost of equity with a capital structure that contains 100% equity) plus the additional return required for introducing debt and/or preferred stock leverage into the capital structure.

Further, as noted previously, the relatively high market prices of utility stocks cannot be attributed solely to the notion that these companies are expected to earn a return on equity that differs from their cost of equity. Stock prices above book value are common for utility stocks, and indeed the stock prices of non-regulated companies exceed book values by even greater margins. In this regard, according to the Barron's issue of February 8, 2016, the major market indices' market-to-book ratios are well above unity. The Dow Jones Utility index traded at a multiple of 1.90 times book value, which is below the market multiple of other indices. For example, the S&P Industrial index was at 3.39 times book value, and the Dow Jones Industrial index was at 2.97 times book value. It is difficult to accept that the vast majority of all firms operating in our economy are generating returns far in excess of their cost of capital. Certainly, in our free-market economy, competition should contain such "excesses" if they indeed exist.

Finally, the leverage adjustment adds stability to the final DCF cost rate. That is to say, as the market capitalization increases relative to its book value, the leverage adjustment increases while the simple yield (D/P) plus growth (g) result declines. The reverse is also true that when the market capitalization declines, the leverage adjustment also declines as the simple yield (D/P) plus growth (g) result increases.

Q. Is the leverage adjustment that you propose designed to transform the market return into one that is designed to produce a particular market-to-book ratio?

A. No, it is not. The adjustment that I label as a "leverage adjustment" is merely a convenient way of showing the amount that must be added to (or subtracted from) the result of the simple DCF model (i.e., D/P + g), in the context of a return that applies to the capital structure used in ratemaking, which is computed with book value weights rather than market value weights, in order to arrive at the utility's total cost of equity. I specify a separate factor, which I call the leverage adjustment, but there is no need to do so other than providing identification for this factor. If I expressed my return solely in the context of the book value weights that we use to calculate the weighted average cost of capital, and ignore the familiar D/P + g expression entirely, then there would be no separate element to reflect the financial leverage change from market value to book value capitalization. As shown in the bottom panel of data on Schedule 10, the equity return applicable to the book value common equity ratio is equal to 8.30%, which is 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) plus 2.08% compensation for having a 44.61% debt ratio, plus 0.01% for having a 0.18% preferred stock ratio. The sum of the parts is 10.39% (8.30% + 2.08% + 0.01%) and there is no need to even address the cost of equity in terms of D/P + g. To express this same return in the context of the familiar DCF model, I summed the 3.32% dividend yield, the 6.25% growth rate, and the 0.82% for the leverage adjustment in order to arrive at the same 10.39% (3.32% + 6.25% + 0.82%) return. I know of no means to mathematically solve for the 0.82% leverage adjustment by expressing it in the terms of any particular relationship of market price to book value. The 0.82% adjustment is merely a convenient way to compare the 10.39% return computed directly with the Modigliani & Miller formulas to the 9.57% return generated by the DCF model based on a market value capital structure. My point is that when we use a market-determined cost of equity developed from the DCF model, it reflects a level of financial risk that is different (in this case, lower) from the capital structure stated at book value. This process has nothing to do with targeting any particular market-to-book ratio.

Q. Please provide the DCF return based upon your preceding discussion of dividend yield, growth, and leverage.

A. As explained previously, I have utilized a six-month average dividend yield ("D_1/P_0") adjusted in a forward-looking manner for my DCF calculation. This dividend yield is used in conjunction with the growth rate ("g") previously developed. The DCF also includes the leverage modification ("lev.") required when the book value equity ratio is used in determining the weighted average cost of capital in the ratesetting process rather than the market value equity ratio related to the price of stock. The resulting DCF cost rate is:

	D_1/P_0	+	g	+	$lev.$	=	K
Gas Group	3.32%	+	6.25%	+	0.82%	=	10.39%

I also note that the 6.25% growth rate for the Gas Group understates growth for CPA, given CPA's higher proportion of projected construction expenditures relative to the average annual expenditures for the Gas Group. This suggests that other equity cost rate models should be given weight in arriving at the cost of equity. The DCF result shown above represents the simplified (i.e., Gordon) form of the model that contains a constant growth assumption. I should reiterate, however, that the DCF-indicated cost rate provides an explanation of the rate of return on common stock market prices without regard to the prospect of a change in the price-earnings multiple. An assumption that there will be no change in the price-earnings multiple is not supported by the realities of the equity market, because price-earnings multiples do not remain constant. This is one of the constraints of this model that makes it important to consider other model results when determining a company's cost of equity. As noted previously, CPA has weaker credit quality as compared to the Gas Group. A generally accepted tenet of corporate finance is that risk and return are linked. Here, weaker credit quality adds to risk. As a consequence, an upward adjustment to the DCF results is required to accommodate the risk of CPA vis-á-vis the Gas Group.

Q. What is the adjustment to recognize the weaker credit quality of CPA?

A. The DCF returns that are produced for the Gas Group relate to the average credit quality of that group, which is A2/A- as shown on page 2 of Schedule 3. In order to provide recognition of the additional return that is required to compensate CPA for its higher risk in this regard, I have reviewed the difference in yields on A-rated and Baa-rated public utility debt. The yield difference is related to the additional return required when risk increases, i.e., generally bond yields increase as credit quality declines. The yield difference between A-rated and Baa-rated public utility bonds is used as a proxy for quantifying this additional risk.

As shown by the data presented on page 1 of Schedule 11, the difference in yields between Baa-rated and A-rated public utility bonds was 1.06% (5.41% - 4.35%) for the six-months ended December 2015. Based on this difference in yields, I propose that a 40 basis points be added to the DCF calculation for the Gas Group to provide recognition for the higher risk of CPA due to its weaker credit quality risk, its small size, competitive forces in its service territory, and significant construction expenditures. The bond yield difference between A-rated and Baa-rated debt have been elevated recently. To take a conservative position on this issue and to select a position more similar to prior cases, I have used a much lower yield difference in this case. As such, the DCF return requires adjustment to 10.79% (10.39% + 0.40%) to recognize the higher risk of CPA.

RISK PREMIUM ANALYSIS

Q. Please describe your use of the risk premium approach to determine the cost of equity.

A. With the Risk Premium approach, the cost of equity capital is determined by corporate bond yields plus a premium to account for the fact that common equity is exposed to greater investment risk than debt capital. The result of my Risk Premium study is shown on page 2 of Schedule 1. That result is 11.90%. As with other models used to determine the cost of equity, the Risk Premium approach has its limitations, including potential imprecision in the assessment of the future cost of corporate debt and the measurement of the risk-adjusted common equity premium.

Q. What long-term public utility debt cost rate did you use in your risk premium analysis?

A. In my opinion, a 5.00% yield represents a reasonable estimate of the prospective yield on long-term A-rated public utility bonds.

Q. What historical data is shown by the Moody's data?

A. I have analyzed the historical yields on the Moody's index of long-term public utility debt as shown on page 1 of Schedule 11. For the twelve months ended December 2015, the average monthly yield on Moody's index of A-rated public utility bonds was 4.12%. For the six and three-month periods ended December 2014, the yields were 4.35% and 4.35%, respectively. During the twelve-months ended December 2015, the range of the yields on A-rated public utility bonds was 3.58% to 4.40%. Page 2 of Schedule 12 shows the long-run spread in yields between A-rated public utility bonds and long-term Treasury bonds. As shown on page 3 of Schedule 11, the yields on A-rated public utility bonds have exceeded those on Treasury bonds by 1.27% on a twelve-month average basis, 1.39% on a six-month average basis, and 1.38% on a the three-month average basis. From these averages, 1.25% represents a reasonably conservative spread for the yield on A-rated public utility bonds over Treasury bonds.

Q. What forecasts of interest rates have you considered in your analysis?

A. I have determined the prospective yield on A-rated public utility debt by using the Blue Chip Financial Forecasts ("Blue Chip") along with the spread in the yields that I describe below. The Blue Chip is a reliable authority and contains consensus forecasts of a variety of interest rates compiled from a panel of banking, brokerage, and investment advisory services. In early 1999, Blue Chip stopped publishing forecasts of yields on A-rated public utility bonds because the Federal Reserve deleted these yields from its Statistical Release H.15. To independently project a forecast of the yields on A-rated public utility bonds, I have combined the forecast yields on long-term Treasury bonds published on January 1, 2016, and a yield spread of 1.25%, derived from historical data.

Q. How have you used these data to project the yield on A-rated public utility bonds for the purpose of your Risk Premium analyses?

A. Shown below is my calculation of the prospective yield on A-rated public utility bonds using the building blocks discussed above, i.e., the Blue Chip forecast of Treasury bond yields and the public utility bond yield spread. For comparative purposes, I also have shown the Blue Chip forecasts of Aaa-rated and Baa-rated corporate bonds. These forecasts are:

		Blue Chip Financial Forecasts				
		Corporate		30-Year	A-rated Public Utility	
Year	Quarter	Aaa-rated	Baa-rated	Treasury	Spread	Yield
2016	First	4.1%	5.4%	3.1%	1.25%	4.35%
2016	Second	4.3%	5.6%	3.2%	1.25%	4.45%
2016	Third	4.4%	5.7%	3.4%	1.25%	4.65%
2016	Fourth	4.7%	5.9%	3.5%	1.25%	4.75%
2017	First	4.8%	6.0%	3.7%	1.25%	4.95%
2017	Second	4.9%	6.1%	3.8%	1.25%	5.05%

Q. Are there additional forecasts of interest rates that extend beyond those shown above?

A. Yes. Twice yearly, Blue Chip provides long-term forecasts of interest rates. In its December 1, 2015 publication, Blue Chip published longer-term forecasts of interest rates, which were reported to be:

	Blue Chip Financial Forecasts		
	Corporate		30-Year
Averages	Aaa-rated	Baa-rated	Treasury
2017-2021	5.6%	6.5%	4.5%
2022-2026	5.8%	6.8%	4.8%

The longer term forecasts by Blue Chip suggest that interest rates will move up from the levels revealed by the near term forecasts. By focusing more on the near term forecasts, a 5.00% yield on A-rated public utility bonds represents a conservative benchmark for measuring the cost of equity in this case.

Q. What equity risk premium have you determined for public utilities?

A. To develop an appropriate equity risk premium, I analyzed the results from Stocks, Bonds, Bills and Inflation ("SBBI") 2015 Classic Yearbook published by Ibbotson Associates that is part of Morningstar. My investigation reveals that the equity risk premium varies according to the level of interest rates. That is to say, the equity risk premium increases as interest rates decline and it declines as interest rates increase. This inverse relationship is revealed by the summary data presented below and shown on page 1 of Schedule 12.

Common Equity Risk Premiums	
Low Interest Rates	7.36%
Average Across All Interest Rates	5.69%
High Interest Rates	3.98%

Based on my analysis of the historical data, the equity risk premium was 7.36% when the marginal cost of long-term government bonds was low (i.e., 3.00%, which was the average yield during periods of low rates). Conversely, when the yield on long-term government bonds was high (i.e., 7.28% on average during periods of high interest rates) the spread narrowed to 3.98%. Over the entire spectrum of interest rates, the equity risk premium was 5.69% when the average government bond yield was 5.12%. With the forecast indicating an upward movement of interest rates that I described above from historically low levels, I have utilized a 6.50% equity risk premium. This equity risk premium is between the 7.36% premium related to periods of low interest rates and the 5.69% premium related to average interest rates across all levels.

Q. What common equity cost rate did you determine based on your risk premium analysis?

A. The cost of equity (i.e., "k") is represented by the sum of the prospective yield for long-term public utility debt (i.e., "i"), and the equity risk premium (i.e., "RP"). The Risk Premium approach provides a cost of equity of:

	i	+	*RP*	=	*k*
Gas Group	5.00%	+	6.50%	=	11.50%

As I noted previously, NiSource carries a Baa2/BBB+ rating on its debt. This means that the Risk Premium cost rate shown above would understate the Company's cost of equity by 40 basis points, because the 11.50% shown above is based on the yield on A-rated public utility debt and to account for the Company's small size, competitive forces in its service territory, and significant construction expenditures, the Risk Premium cost rate for CPA is 11.90% (11.50% + 0.40%).

CAPITAL ASSET PRICING MODEL

Q. What are the features of the CAPM as you have used it?

A. The CAPM uses the yield on a risk-free interest bearing obligation plus a rate of return premium that is proportional to the systematic risk of an investment. As shown on page 2 of Schedule 1, the result of the CAPM is 11.16%. To compute the cost of equity with the CAPM, three components are necessary: a risk-free rate of return ("Rf"), the beta measure of systematic risk ("β"), and the market risk premium ("Rm-Rf") derived from the total return on the market of equities reduced by the risk-free rate of return. The CAPM specifically accounts for differences in systematic risk (i.e., market risk as measured by the beta) between an individual firm or group of firms and the entire market of equities.

Q. What betas have you considered in the CAPM?

A. For my CAPM analysis, I initially considered the Value Line betas. As shown on page 2 of Schedule 3, the average beta is 0.74 for the Gas Group.

Q. What betas have you used in the CAPM determined cost of equity?

A. The betas must be reflective of the financial risk associated with the ratesetting capital structure that is measured at book value. Therefore, Value Line betas cannot be used directly in the CAPM, unless the cost rate developed using those betas is applied to a capital structure measured with market values. To develop a CAPM cost rate applicable to a book-value capital structure, the Value Line (market value) betas have been unleveraged and releveraged for the book value common equity ratios using the Hamada formula,[8] as follows:

$$\beta l = \beta u\,[1 + (1 - t)\, D/E + P/E]$$

where ßl = the leveraged beta, ßu = the unleveraged beta, t = income tax rate, D = debt ratio, P = preferred stock ratio, and E = common equity ratio. The betas published by Value Line have been calculated with the market price of stock and are related to the market value capitalization. By using the formula shown above and the capital structure ratios measured at market value, the beta would become 0.56 for the Gas Group if it employed no leverage and was 100% equity financed. Those calculations are shown on Schedule 10 under the section labeled "Hamada" who is credited with developing those formulas. With the unleveraged beta as a base, I calculated the leveraged beta of 0.86 for the book value capital structure of the Gas Group. The book value leveraged beta that I will employ in the CAPM cost of equity is 0.86 for the Gas Group.

Q. What risk-free rate have you used in the CAPM?

A. As shown on page 1 of Schedule 13, I provided the historical yields on Treasury notes and bonds. For the twelve months ended December 2015, the average yield on 30-year Treasury bonds was 2.84%. For the six- and three-months ended December 2015, the yields on 30-year Treasury bonds were 2.96% and 2.96%, respectively. During the twelve-months ended December 2015, the range of the yields on 30-year Treasury bonds was 2.46% to 3.11%. The low yields that existed during recent periods can be traced to the financial crisis and its aftermath commonly

[8] Robert S. Hamada, "The Effects of the Firm's Capital Structure on the Systematic Risk of Common Stocks" *The Journal of Finance* Vol. 27, No. 2, Papers and Proceedings of the Thirtieth Annual Meeting of the American Finance Association, New Orleans, Louisiana, December 27-29, 1971. (May 1972), pp.435-452.

referred to as the Great Recession. The resulting decline in the yields on Treasury obligations was attributed to a number of factors, including: the sovereign debt crisis in the euro zone, concern over a possible double dip recession, the potential for deflation, and the Federal Reserve's large balance sheet that was expanded through the purchase of Treasury obligations and mortgage-backed securities (also known as QEI, QEII, and QEIII), and the reinvestment of the proceeds from maturing obligations and the lengthening of the maturity of the Fed's bond portfolio through the sale of short-term Treasuries and the purchase of long-term Treasury obligations (also known as "operation twist"). Essentially, low interest rates were the product of the policy of the FOMC in its attempt to deal with stagnant job growth, which is part of its dual mandate. The FOMC has ended its bond purchasing program. And, at its December 16, 2015 meeting, the Federal Open Market Committee increased the federal funds rate range by 0.25 percentage points. The prospect exists that future increases in the federal funds rate will likely occur.

As shown on page 2 of Schedule 13, forecasts published by Blue Chip on January 1, 2016 indicate that the yields on long-term Treasury bonds are expected to be in the range of 3.1% to 3.8% during the next six quarters. The longer term forecasts described previously show that the yields on 30-year Treasury bonds will average 4.5% from 2017 through 2021 and 4.8% from 2022 to 2026. For the reasons explained previously, forecasts of interest rates should be emphasized at this time in selecting the risk-free rate of return in CAPM. Hence, I have used a 3.75% risk-free rate of return for CAPM purposes, which considers not only the Blue Chip forecasts, but also the recent trend in the yields on long-term Treasury bonds.

Q. What market premium have you used in the CAPM?

A. As shown in the lower panel of data presented on page 2 of Schedule 13, the market premium is derived from historical data and the Value Line and S&P 500 returns.

For the historically based market premium, I have used the arithmetic mean obtained from the data presented on page 1 of Schedule 12. On that schedule, the market return was 12.21% on large stocks during periods of low interest rates. During those periods, the yield on long-term government bonds was 3.00% when interest rates were low. As I describe above, interest rates are forecast to trend upward in the future. To recognize that trend, I have given weight to the average returns and yields that existed across all interest rate levels. As such, I carried over to page 2 of Schedule 13 the average large common stock returns of 12.14% (12.21% + 12.07% = 24.28% ÷ 2) and the average yield on long-term government bonds of 4.06% (3.00% + 5.12% = 8.12% ÷ 2). These financial returns rest between those experienced during periods of low interest rates and those experienced across all levels of interest rates. The resulting market premium is 8.08% (12.14% - 4.06%) based on historical data, as shown on page 2 of Schedule 13. For the forecast returns, I calculated a 13.07% total market return from the Value Line data and a DCF return of 7.61% for the S&P 500. With the average forecast return of 10.34% (13.07% + 7.61% = 20.68% ÷ 2), I calculated a market premium of 6.59% (10.34% - 3.75%) using forecast data. However, I note that a projected DCF return of 7.61% clearly is insufficient to capture the cost of equity capital, making the forecast return conservative. The market premium applicable to the CAPM derived from these sources equals 7.34% (6.59% + 8.08% = 14.67% ÷ 2).

Q. Are there adjustments to the CAPM that are necessary to fully reflect the rate of return on common equity?

A. Yes. The technical literature supports an adjustment relating to the size of the company or portfolio for which the calculation is performed. As the size of a firm decreases, its risk and required return increases. Moreover, in his discussion of the cost of capital, Professor Brigham has indicated that smaller firms have higher capital costs than otherwise similar larger firms.[9] Also, the Fama/French study (see "The Cross-Section of Expected Stock Returns"; The Journal of Finance, June 1992) established that the size of a firm helps explain stock returns. In an October 15, 1995 article in Public Utility Fortnightly, entitled "Equity and the Small-Stock Effect," it was demonstrated that the CAPM could understate the cost of equity significantly according to a company's size. Indeed, it was demonstrated in the SBBI Yearbook that the returns for stocks in lower deciles (i.e., smaller stocks) were in excess of those shown by the simple CAPM. In this regard, the Gas Group has a market-based average equity capitalization of $2,235 million. The mid-cap adjustment of 1.10%, as revealed on page 3 of Schedule 13, would be warranted at a minimum.

Q. What CAPM result have you determined?

A. Using the 3.75% risk-free rate of return, the leverage adjusted beta of 0.86 for the Gas Group, the 7.34% market premium, and the 1.10% size adjustment, the following result is indicated.

	Rf	+	*ß*	x (	*Rm-Rf*	) +	*size*	=	*k*
Water Group	3.75%	+	0.86	x (	7.34%	) +	1.10%	=	11.16%

COMPARABLE EARNINGS APPROACH

Q. How have you applied the Comparable Earnings approach in this case?

A. The Comparable Earnings approach determines the equity return based upon results from non-regulated companies. It is the oldest of all rate of return methods, having been around for about one-century. Because regulation is a substitute for competitively determined prices, the returns realized by non-regulated firms with comparable risks to a public utility provide useful insight into a fair rate of return. In

[9] See Fundamentals of Financial Management, Fifth Edition, at 623.

order to identify the appropriate return, it is necessary to analyze returns earned (or realized) by other firms within the context of the Comparable Earnings standard. The firms selected for the Comparable Earnings approach should be companies whose prices are not subject to cost-based price ceilings (i.e., non-regulated firms) so that circularity is avoided.

There are two avenues available to implement the Comparable Earnings approach. One method involves the selection of another industry (or industries) with comparable risks to the public utility in question, and the results for all companies within that industry serve as a benchmark. The second approach requires the selection of parameters that represent similar risk traits for the public utility and the comparable risk companies. Using this approach, the business lines of the comparable companies become unimportant. The latter approach is preferable with the further qualification that the comparable risk companies exclude regulated firms in order to avoid the circular reasoning implicit in the use of the achieved earnings/book ratios of other regulated firms. The United States Supreme Court has held that:

> A public utility is entitled to such rates as will permit it to earn a return on the value of the property which it employs for the convenience of the public equal to that generally being made at the same time and in the same general part of the country on investments in other business undertakings which are attended by corresponding risks and uncertainties. The return should be reasonably sufficient to assure confidence in the financial soundness of the utility and should be adequate, under efficient and economical management, to maintain and support its credit and enable it to raise the money necessary for the proper discharge of its public duties. Bluefield Water Works vs. Public Service Commission, 262 U.S. 668 (1923).

It is important to identify the returns earned by firms that compete for capital with a public utility. This can be accomplished by analyzing the returns of non-regulated firms that are subject to the competitive forces of the marketplace.

Q. How have you implemented the Comparable Earnings Approach?

A. In order to implement the Comparable Earnings approach, non-regulated companies were selected from The Value Line Investment Survey for Windows that have six categories of comparability designed to reflect the risk of the Gas Group. These screening criteria were based upon the range as defined by the rankings of the companies in the Gas Group. The items considered were: Timeliness Rank, Safety Rank, Financial Strength, Price Stability, Value Line betas, and Technical Rank. The definition for these parameters is provided on page 3 of Schedule 14. The identities of the companies comprising the Comparable Earnings group and their associated rankings within the ranges are identified on page 1 of Schedule 14.

Value Line data was relied upon because it provides a comprehensive basis for evaluating the risks of the comparable firms. As to the returns calculated by Value Line for these companies, there is some downward bias in the figures shown on page 2 of Schedule 14, because Value Line computes the returns on year-end rather than average book value. If average book values had been employed, the rates of return would have been slightly higher. Nevertheless, these are the returns considered by investors when taking positions in these stocks. Because many of the comparability factors, as well as the published returns, are used by investors in selecting stocks, and the fact that investors rely on the Value Line service to gauge returns, it is an appropriate database for measuring comparable return opportunities.

Q. What data have you used in your Comparable Earnings analysis?

A. I have used both historical realized returns and forecasted returns for non-utility companies. As noted previously, I have not used returns for utility companies in order to avoid the circularity that arises from using regulatory-influenced returns to determine a regulated return. It is appropriate to consider a relatively long measurement period in the Comparable Earnings approach in order to cover conditions over an entire business cycle. A ten-year period (five historical years and five projected years) is sufficient to cover an average business cycle. Unlike the DCF and CAPM, the results of the Comparable Earnings method can be applied directly to the book value capitalization. In other words, the Comparable Earnings approach does not contain the potential misspecification contained in market models when the market capitalization and book value capitalization diverge significantly. A point of demarcation was chosen to eliminate the results of highly profitable enterprises, which the Bluefield case stated were not the type of returns that a utility was entitled to earn. For this purpose, I used 20% as the point where those returns could be viewed as highly profitable and should be excluded from the Comparable Earnings approach. The average historical rate of return on book common equity was 13.0% using only the returns that were less than 20%, as shown on page 2 of Schedule 14. The average forecasted rate of return as published by Value Line is 12.6% also using values less than 20%, as provided on page 2 of Schedule 14. Using the Bluefield standard, I have eliminated the results of many companies because of high returns. Using the average of these data my Comparable Earnings result is 12.80%, as shown on page 2 of Schedule 1.

CONCLUSION ON COST OF EQUITY

Q. What is your conclusion regarding the Company's cost of common equity?

A. Based upon the application of the variety of methods and models described previously, I recommend that the Commission set the Company's rate of return on common equity at 11.00%. The proposed rate of return on common equity of 11.00% would provide recognition of the exemplary performance of the Company's management and the high quality of service provided to its customers as explained in the testimony of Mr. Kempic. It is essential that the Commission employ a variety of techniques to measure the Company's cost of equity because of the limitations/infirmities that are inherent in each method.

Q. Does this conclude your direct testimony at this time?

A. Yes, it does.

APPENDIX A TO DIRECT TESTIMONY OF PAUL R. MOUL

EDUCATIONAL BACKGROUND, BUSINESS EXPERIENCE AND QUALIFICATIONS

I was awarded a degree of Bachelor of Science in Business Administration by Drexel University in 1971. While at Drexel, I participated in the Cooperative Education Program which included employment, for one year, with American Water Works Service Company, Inc., as an internal auditor, where I was involved in the audits of several operating water companies of the American Water Works System and participated in the preparation of annual reports to regulatory agencies and assisted in other general accounting matters.

Upon graduation from Drexel University, I was employed by American Water Works Service Company, Inc., in the Eastern Regional Treasury Department where my duties included preparation of rate case exhibits for submission to regulatory agencies, as well as responsibility for various treasury functions of the thirteen New England operating subsidiaries.

In 1973, I joined the Municipal Financial Services Department of Betz Environmental Engineers, a consulting engineering firm, where I specialized in financial studies for municipal water and wastewater systems.

In 1974, I joined Associated Utility Services, Inc., now known as AUS Consultants. I held various positions with the Utility Services Group of AUS Consultants, concluding my employment there as a Senior Vice President.

In 1994, I formed P. Moul & Associates, an independent financial and regulatory consulting firm. In my capacity as Managing Consultant and for the past forty-two years, I have continuously studied the rate of return requirements for cost of service-regulated firms. In this regard, I have supervised the preparation of rate of return studies, which were employed, in connection with my testimony and in the past for other individuals. I have presented direct testimony on the subject of fair rate of return, evaluated rate of return testimony of other witnesses, and presented testimony.

My studies and prepared direct testimony have been presented before thirty-seven (37) federal, state and municipal regulatory commissions, consisting of: the Federal Energy Regulatory Commission; state public utility commissions in Alabama, Alaska, California, Colorado, Connecticut, Delaware, Florida, Georgia, Hawaii, Illinois, Indiana, Iowa, Kentucky, Louisiana, Maine, Maryland, Massachusetts, Michigan, Minnesota, Missouri, New Hampshire, New Jersey, New York, North Carolina, Ohio, Oklahoma, Pennsylvania, Rhode Island, South Carolina, Tennessee, Texas, Virginia, West Virginia, Wisconsin, and the Philadelphia Gas Commission, and the Texas Commission on Environmental Quality. My testimony has been offered in over 200 rate cases involving electric power, natural gas distribution and transmission, resource recovery, solid waste collection and disposal, telephone, wastewater, and water service utility companies. While my testimony has involved principally fair rate of return and financial matters, I have also testified on capital allocations, capital recovery, cash working capital, income taxes, factoring of accounts receivable, and take-or-pay expense recovery. My testimony has been offered on behalf of municipal and investor-owned public utilities and for the staff of a regulatory commission. I have also testified at an Executive Session of the State of New Jersey Commission of Investigation concerning the BPU regulation of solid waste collection and disposal.

I was a co-author of a verified statement submitted to the Interstate Commerce Commission concerning the 1983 Railroad Cost of Capital (Ex Parte No. 452). I was also co-author of comments submitted to the Federal Energy Regulatory Commission regarding the Generic Determination of Rate of Return on Common Equity for Public Utilities in 1985, 1986 and 1987 (Docket Nos. RM85-19-000, RM86-12-000, RM87-35-000 and RM88-25-000). Further, I have been the consultant to the New York Chapter of the National Association of Water Companies, which represented the water utility group in the

Proceeding on Motion of the Commission to Consider Financial Regulatory Policies for New York Utilities (Case 91-M-0509). I have also submitted comments to the Federal Energy Regulatory Commission in its Notice of Proposed Rulemaking (Docket No. RM99-2-000) concerning Regional Transmission Organizations and on behalf of the Edison Electric Institute in its intervention in the case of Southern California Edison Company (Docket No. ER97-2355-000). Also, I was a member of the panel of participants at the Technical Conference in Docket No. PL07-2 on the Composition of Proxy Groups for Determining Gas and Oil Pipeline Return on Equity.

In late 1978, I arranged for the private placement of bonds on behalf of an investor-owned public utility. I have assisted in the preparation of a report to the Delaware Public Service Commission relative to the operations of the Lincoln and Ellendale Electric Company. I was also engaged by the Delaware P.S.C. to review and report on the proposed financing and disposition of certain assets of Sussex Shores Water Company (P.S.C. Docket Nos. 24-79 and 47-79). I was a co-author of a Report on Proposed Mandatory Solid Waste Collection Ordinance prepared for the Board of County Commissioners of Collier County, Florida.

I have been a consultant to the Bucks County Water and Sewer Authority concerning rates and charges for wholesale contract service with the City of Philadelphia. My municipal consulting experience also included an assignment for Baltimore County, Maryland, regarding the City/County Water Agreement for Metropolitan District customers (Circuit Court for Baltimore County in Case 34/153/87-CSP-2636).

Columbia Gas of Pennsylvania, Inc. Compliance Filing Calculations – September 2015

20-Year Intercompany Note Issuance

Term Selection

A 20-year term was selected for the note issuance to take advantage of the current interest rate environment, where long-term interest rates are near historic lows, and to stagger the debt maturities of Columbia Gas of Pennsylvania (Columbia). Choosing the 20-year term "locks-in" a favorable rate of financing for Columbia for an extended period of time, eliminates interest rate risk during the financing term, and also appropriately matches Columbia's long-term liabilities with its long-term assets.

Interest Rate Determination

The interest rate for the note was determined using a different methodology from the methodology outlined in Columbia's latest Registration of Securities Certificate. Annex A explains why Columbia feels the new methodology is appropriate and beneficial to Pennsylvania customers. Below is the interest rate calculation using the new methodology and, for comparison purposes, the interest rate calculation using the methodology from the latest Registration of Securities Certificate.

New Methodology (Used to Determine Interest Rate)

Interest Rate on 20-year bond for BBB+ rated utilities at September 28, 2015 equals 4.5051%. Source: Bloomberg (1)

20-Year Treasury Bond Yield at September 28, 2015 equals 2.510%. Source: Federal Reserve Statistical Release, H.15 Selected Interest Rates (Daily), dated October 5, 2015 (2).

The implied 20-Year Corporate Credit Spread for BBB+ rated utilities at September 28, 2015 equals 1.9951%, which is equal to the Interest Rate of 4.5051% minus the Treasury Bond Yield of 2.5100%

Total Intercompany Note Rate = 2.5100% + 1.9951% = 4.5051%.

Footnotes:

(1) 4.5051% is rate shown on the Bloomberg screen C03820Y in the row labeled Mo 09/28/15 and the column labeled Mid Yield.
(2) The 2.510% yield is shown on page 2 of the Statistical Release within the "Treasury constant maturities Nominal" section, in the row labeled "20-year" and the column labeled "2015 Sep 28".

Methodology from Latest Registration of Securities Certificate (Not Used to Determine Interest Rate)

20-Year Treasury Bond Yield at September 28, 2015 equals 2.510%. Source: Federal Reserve Statistical Release, H.15 Selected Interest Rates (Daily), dated September 29, 2015 (1).

20-Year Corporate Credit Spread for Baa1/BBB+ rated utilities at September 28, 2015 is calculated to be 2.450%. This spread is interpolated using the 20-Year Corporate Credit Spreads for A2/A and Baa2/BBB utilities at September 28, 2015.

20-Year Corporate Credit Spread for A2/A rated utilities at September 28, 2015 equals 1.77%. Source: Reuters Corporate Spreads for Utilities, dated September 28, 2015 (2)

20-Year Corporate Credit Spread for Baa2/BBB rated utilities at September 28, 2015 equals 2.79%. Source: Reuters Corporate Spreads for Utilities, dated September 28, 2015 (2)

Credit Spread for Baa1/BBB+ rated utility = 2.79% - (2.79% - 1.77%) / 3 = 2.450%

Total Intercompany Note Rate = 2.510% + 2.450% = 4.960%.

Footnotes:

(1) The 2.510% yield is shown on page 2 of the Statistical Release within the "Treasury constant maturities Nominal" section, in the row labeled "20-year" and the column labeled "2015 Sep 28".

(2) The 1.77% corporate credit spread is shown on page 1 of the Reuters Corporate Spreads report in the row labeled "A2/A" and the column labeled "20 yr". The 2.79% corporate credit spread is shown on page 1 of the Reuters Corporate Spreads report in the row labeled "Baa2/BBB" and the column labeled "20 yr".

ANNEX A

The current methodology for determining interest rates on intercompany notes, which is outlined in Columbia's latest Registration of Securities Certificate, is as follows:

"The Note's interest rate will be determined by the corresponding applicable Treasury yield (as reported in Federal Reserve Statistical Release, H.15 Selected Interest Rates (Daily)) effective on the date a Note is issued, plus the yield spread on corresponding maturities for companies with a credit profile equivalent to that of NiSource Finance Corp. (as reported by Reuters Corporate Spreads) effective on the date a Note is issued."

In August 2015, Reuters changed its methodology for reporting yield spreads. Prior to August 2015 the methodology produced spreads for all credit rating notches from Aaa/AAA to Caa/CCC+. Beginning in August 2015 the methodology no longer produces spreads for each rating notch and only produces spreads for the main rating levels (i.e., A2/A, Baa2/BBB, Ba2/BB and B2/B). The spread for each rating level are based on actively priced bonds in that level. For example, the spread for the Baa2/BBB level is based on spreads for actively priced bonds with ratings of Baa1/BBB+, Baa2/BBB and Baa3/BBB-.

Since a specific yield spread is not provided for BBB+ (NiSource Finances' current S&P rating), a spread would need to be interpolated using the data available from Reuters. Based on the September 28, 2015 data available from Reuters, the interpolated spread for a 20-year bond issued by Baa1/BBB+ utilities is 245 bps. This interpolated spread is significantly higher than one would expect in the current rate environment. Using this interpolated spread would result in an artificially high interest rate that would negatively impact Pennsylvania customers.

Therefore, Columbia is proposing a new methodology for determining the interest rate. Under the new methodology a Note's interest rate will be determined by the corresponding applicable yield for utility companies with a credit profile equivalent to that of NiSource Finance Corp. (as reported by Bloomberg) effective on the date a Note is issued. In addition to providing support for this rate, Columbia will also provide the corresponding applicable Treasury yield and the implied yield spread. The Treasury yield will be as reported in Federal Reserve Statistical Release, H.15 Selected Interest Rates (Daily) effective on the date a Note is issued. The implied yield spread will be calculated by subtracting the Treasury yield from the Note's interest rate.

Under this new methodology, the calculated yield spreads for a 20-year bond issued by BBB+ utilities is 199.51 bps. This is in line with what one would expect in the current rate environment.

The interest rate determined by the new methodology is more favorable to customers and more reflective of the current environment as compared to the interest rate determined by the methodology outlined in the latest Registration of Securities Certificate.

C03820Y 4.4774 -.0277 4.4774/4.4774

At 9/29 Op 4.4774 Hi 4.4774 Lo 4.4774 Prev 4.5051 Vol 0

C03820Y Index | 96) Export to Excel | Page 1/6 | Historical Price Table

BFV USD US Utility BBB+ 20 Year

Range 10/01/2014 - 09/29/2015 Period Daily

Market Mid Yield Currency

View Price Table

High	4.7144	on	09/15/15	
Low	3.6451	on	02/02/15	
Average	4.2568			
Net Chg	.1707			3.96%

Date	Mid Yield	Date	Mid Yield	Date	Mid Yield
Fr 10/02/15		Fr 09/11/15	4.5755	Fr 08/21/15	4.3828
Th 10/01/15		Th 09/10/15	4.6178	Th 08/20/15	4.4254
We 09/30/15		We 09/09/15	4.5824	We 08/19/15	4.4628
Tu 09/29/15	4.4774	Tu 09/08/15	4.6200	Tu 08/18/15	4.4993
Mo 09/28/15	4.5051	Mo 09/07/15	4.5503	Mo 08/17/15	4.4485
Fr 09/25/15	4.5782	Fr 09/04/15	4.5503	Fr 08/14/15	4.4670
Th 09/24/15	4.5360	Th 09/03/15	4.5907	Th 08/13/15	4.4559
We 09/23/15	4.5768	We 09/02/15	4.6139	We 08/12/15	4.4172
Tu 09/22/15	4.5696	Tu 09/01/15	4.5884	Tu 08/11/15	4.3918
Mo 09/21/15	4.6343	Mo 08/31/15	4.6326	Mo 08/10/15	4.4756
Fr 09/18/15	4.5498	Fr 08/28/15	4.5963	Fr 08/07/15	4.4101
Th 09/17/15	4.6251	Th 08/27/15	4.5876	Th 08/06/15	4.4723
We 09/16/15	4.7136	We 08/26/15	4.5744	We 08/05/15	4.5146
Tu 09/15/15 H	4.7144	Tu 08/25/15	4.4695	Tu 08/04/15	4.4670
Mo 09/14/15	4.5959	Mo 08/24/15	4.3767	Mo 08/03/15	4.3940

H15T20Y 2.48 As Of 09/29/15

US Treasury Yield Curve Rate T Note Constant Maturity 20 Year

H15T20Y Index | 96) Export to Excel | Page 1/6 | Historical Price Table

US Treasury Yield Curve Rate T Note Constant Maturity 20 Year

Range 11/06/2014 - 09/29/2015 Period Daily

Market Last Price Mid Line Currency USD

View Price Table

High	2.98	on	06/26/15
Low	2.04	on	01/30/15
Average	2.55		2.55
Net Chg	-.35		-12.37%

Date	Last Price	Mid Line	Date	Last Price	Mid Line	Date	Last Price	Mid Line
Fr 10/02/15			Fr 09/11/15	2.63	2.63	Fr 08/21/15	2.44	2.44
Th 10/01/15			Th 09/10/15	2.66	2.66	Th 08/20/15	2.45	2.45
We 09/30/15			We 09/09/15	2.64	2.64	We 08/19/15	2.49	2.49
Tu 09/29/15	2.48	2.48	Tu 09/08/15	2.66	2.66	Tu 08/18/15	2.56	2.56
Mo 09/28/15	2.51	2.51	Mo 09/07/15			Mo 08/17/15	2.51	2.51
Fr 09/25/15	2.60	2.60	Fr 09/04/15	2.58	2.58	Fr 08/14/15	2.54	2.54
Th 09/24/15	2.55	2.55	Th 09/03/15	2.64	2.64	Th 08/13/15	2.54	2.54
We 09/23/15	2.60	2.60	We 09/02/15	2.66	2.66	We 08/12/15	2.52	2.52
Tu 09/22/15	2.60	2.60	Tu 09/01/15	2.62	2.62	Tu 08/11/15	2.50	2.50
Mo 09/21/15	2.67	2.67	Mo 08/31/15	2.64	2.64	Mo 08/10/15	2.58	2.58
Fr 09/18/15	2.58	2.58	Fr 08/28/15	2.61	2.61	Fr 08/07/15	2.52	2.52
Th 09/17/15	2.69	2.69	Th 08/27/15	2.61	2.61	Th 08/06/15	2.59	2.59
We 09/16/15	2.75	2.75	We 08/26/15	2.64	2.64	We 08/05/15	2.64	2.64
Tu 09/15/15	2.73	2.73	Tu 08/25/15	2.54	2.54	Tu 08/04/15	2.59	2.59
Mo 09/14/15	2.62	2.62	Mo 08/24/15	2.42	2.42	Mo 08/03/15	2.55	2.55

FEDERAL RESERVE statistical release

H.15 (519) SELECTED INTEREST RATES
Yields in percent per annum

For use at 2:30 p.m. Eastern Time
October 5, 2015

Instruments	2015 Sep 28	2015 Sep 29	2015 Sep 30	2015 Oct 1	2015 Oct 2	Week Ending Oct 2	Week Ending Sep 25	2015 Sep
Federal funds (effective)[1 2 3]	0.13	0.13	0.07	0.13	0.13	0.12	0.14	0.14
Commercial Paper[3 4 5 6]								
Nonfinancial								
1-month	0.12	0.11	0.12	0.11	0.11	0.11	0.13	0.13
2-month	0.12	0.14	0.13	0.14	0.13	0.13	0.15	0.17
3-month	0.20	0.22	0.20	0.20	0.18	0.20	0.19	0.22
Financial								
1-month	n.a.	0.13	n.a.	0.10	0.15	0.13	0.15	0.15
2-month	n.a.	0.16	0.20	0.21	0.21	0.20	0.20	0.21
3-month	0.25	0.22	0.27	0.26	0.27	0.25	0.27	0.27
Eurodollar deposits (London)[3 7]								
1-month	0.19	0.19	0.19	0.19	0.19	0.19	0.19	0.19
3-month	0.33	0.33	0.33	0.33	0.33	0.33	0.33	0.33
6-month	0.46	0.46	0.46	0.46	0.46	0.46	0.46	0.46
Bank prime loan[2 3 8]	3.25	3.25	3.25	3.25	3.25	3.25	3.25	3.25
Discount window primary credit[2 9]	0.75	0.75	0.75	0.75	0.75	0.75	0.75	0.75
U.S. government securities								
Treasury bills (secondary market)[3 4]								
4-week	-0.02	-0.01	-0.02	-0.01	-0.02	-0.02	-0.02	-0.00
3-month	0.01	0.01	-0.01	-0.02	0.00	-0.00	0.00	0.02
6-month	0.10	0.09	0.08	0.08	0.06	0.08	0.09	0.18
1-year	0.32	0.31	0.31	0.29	0.23	0.29	0.33	0.35
Treasury constant maturities								
Nominal[10]								
1-month	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01
3-month	0.01	0.01	0.00	0.00	0.00	0.00	0.01	0.02
6-month	0.10	0.09	0.08	0.08	0.06	0.08	0.09	0.18
1-year	0.34	0.33	0.33	0.31	0.25	0.31	0.34	0.37
2-year	0.67	0.64	0.64	0.64	0.58	0.63	0.70	0.71
3-year	0.97	0.92	0.92	0.92	0.85	0.92	0.99	1.01
5-year	1.42	1.37	1.37	1.37	1.29	1.36	1.47	1.49
7-year	1.80	1.74	1.75	1.75	1.67	1.74	1.86	1.88
10-year	2.10	2.05	2.06	2.05	1.99	2.05	2.16	2.17
20-year	2.51	2.48	2.51	2.49	2.44	2.49	2.60	2.62
30-year	2.87	2.85	2.87	2.85	2.82	2.85	2.96	2.95
Inflation indexed[11]								
5-year	0.40	0.34	0.30	0.24	0.14	0.28	0.32	0.33
7-year	0.57	0.51	0.48	0.42	0.33	0.46	0.51	0.52
10-year	0.71	0.66	0.65	0.59	0.51	0.62	0.66	0.65
20-year	1.06	1.04	1.05	0.99	0.93	1.01	1.04	1.01
30-year	1.28	1.27	1.29	1.23	1.18	1.25	1.28	1.24
Inflation-indexed long-term average[12]	1.07	1.05	1.05	1.00	0.93	1.02	1.06	1.03
Interest rate swaps[13]								
1-year	0.51	0.50	0.50	0.50	0.46	0.49	0.51	0.53
2-year	0.78	0.76	0.75	0.76	0.69	0.75	0.80	0.83
3-year	1.03	1.01	0.99	1.00	0.92	0.99	1.06	1.11
4-year	1.26	1.23	1.20	1.21	1.12	1.20	1.30	1.34
5-year	1.46	1.42	1.39	1.40	1.31	1.39	1.50	1.55
7-year	1.78	1.74	1.70	1.71	1.62	1.71	1.83	1.87
10-year	2.09	2.04	2.01	2.01	1.93	2.01	2.15	2.19
30-year	2.59	2.55	2.53	2.51	2.46	2.53	2.67	2.68
Corporate bonds								
Moody's seasoned								
Aaa[14]	3.99	3.97	4.00	3.98	3.95	3.98	4.03	4.07
Baa	5.31	5.31	5.35	5.36	5.33	5.33	5.33	5.34
State & local bonds[15]				3.67		3.67	3.71	3.78
Conventional mortgages[16]				3.85		3.85	3.86	3.89

See overleaf for footnotes.
n.a. Not available.

COLUMBIA STATEMENT NO. 9

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2016-2529660
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
NANCY J.D. KRAJOVIC
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

I. Introduction

Q. Please state your name and business address.

A. Nancy J. D. Krajovic, 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 State Finance Director.

Q. What are your responsibilities as State Finance Director?

A. I am responsible for analysis and support in the financial planning, forecasting and O&M and capital budgeting processes for Columbia and coordination with the NiSource Corporate financial planning and budgeting processes.

Q. What is your educational and professional background?

A. I hold a Bachelor's of Science Degree in Accounting from Duquesne University and a Master of Business Administration from the University of Pittsburgh's Katz Graduate School of Business. I was employed by the Pennsylvania Public Utility Commission ("Commission") from 1984 through 1987 as an auditor. From 1988 through 2007, I held various regulatory positions at Duquesne Light Company including Regulatory Analyst, Rate Design Coordinator, Project Manager, Director of Regulatory Affairs and Manager of Regulatory Affairs. In those positions I acted as the primary interface with the Commission in the conduct of financial and management audits of Duquesne Light. Additionally, I was responsible for the interpretation and administration of Duquesne's retail and supplier tariffs. In

2007, I assumed the role of Manager, Commercial and Industrial Customers for Duquesne Light and held that position until May 2009. In November of 2009, I joined Columbia as Senior Regulatory Analyst and was promoted to Director of Rates and Regulatory Affairs in June of 2011. In July of 2015 I transferred to my current role as State Finance Director.

Q. Have you previously testified before this Commission?

A. Yes, I have submitted written testimony before the Commission on Duquesne's behalf at the following dockets: I-900005, M-00930404C001, R-00016854C001, M-FACE0302, R-00061346 and P-00072247. I also presented oral testimony in several formal customer complaint actions and at en banc hearings sponsored by the Commission on energy conservation issues. Additionally, I have submitted written testimony before the Commission on behalf of Columbia at the following dockets: R-2011-2215623, R-2012-2293303, R-2012-2321748, R-2013-2351073, R-2014-2406274, R-2014-2408268, R-2015-2468056, R-2015-2469665, P-2012-2338282 and C-2011-2248370/A-2011-2276780.

Q. What is the purpose of your testimony in this proceeding?

A. My testimony supports Columbia's projected Operations and Maintenance ("O&M") expenses for the Fully Forecasted Rate Year (through December 31, 2017), that have been incorporated in Columbia witness Miller's cost of service analysis.

Q. What is the basis for the forecasted O&M expense included in the Fully Forecasted Rate Year?

A. The forecasted O&M expense included in the Fully Forecasted Rate Year test period is derived from the Company's most recent O&M budget.

Q. How is Columbia's O&M expense budget developed?

A. The O&M expense budgeting methodology used by Columbia is a combination of a "top down" and "grass roots" approach. The O&M expense budget serves as a key component of the overall Columbia budget and as a cost management tool for both NiSource Corporate Services Company ("NCSC") and Columbia management.

Q. Please explain.

A. The NCSC management team, including Columbia's management team, first identifies general O&M requirements and planning objectives in conjunction with NiSource Inc.'s senior management. These requirements and objectives are then communicated to each successive layer of management and employees, as well as the NCSC Financial Planning team, which is responsible for the development of all NCSC budgets. It is the responsibility of these groups, working together, to ensure: (1) that Columbia's budgets, including O&M expenses, are developed in accordance with overall financial goals and objectives; and (2), that individual company operational and administrative requirements are addressed.

Q. How is the O&M budget developed?

A. The O&M budget for Columbia is based on a grass roots concept in which individuals who are responsible for approving expenditures are also responsible for budgeting the expenditures. The process generally follows organizational responsibility. Department heads are responsible for overseeing the development of O&M budgets for all cost centers under their control. Budgets originate in operating center locations in the field and other departments representing Columbia's major business functions; these budgets are combined with a corporate-level budget to arrive at a total company budget. I will discuss the corporate-level budget later in my testimony.

Annually, the Company's O&M budget is developed by department by cost element with the assistance of the NCSC Financial Planning department. Each department's budget is reviewed with and approved by the NCSC Chief Financial Officer ("CFO") and Chief Executive Officer ("CEO"). This review includes a comparison of a series of data points based on most recent experience. Specifically, the proposed O&M budget is compared to the most recent year's O&M budget as well as compared to the prior year's actual, experienced amounts. These comparisons help identify trends and allow for measurement against management's expectations. Once finalized, the departmental O&M expense budget is incorporated into the business unit's operating plan.

Q. Does that conclude the development of the O&M expense budgeting process?

A. No. Upon agreement and sign-off on the departmental O&M expense budget, the current year O&M budget is then developed in more detail (i.e., at the individual cost center level) beginning in the preceding fourth quarter for the current year. The process concludes in January.

The current year detailed O&M budget is reviewed against actual results each month throughout the year to determine the reasons for variances and to take appropriate action. If known variances are the result of timing that will be resolved within the year, then those variances are monitored closely but no further action is taken, unless it is deemed, at some point during the year, that the variance will result in a true budget variance at the end of the year. When the review of monthly budget versus actual reveals variances that are expected to last throughout the year, the Financial Planning department and NCSC CFO will work with Columbia management to determine the drivers of the variances and steps to be taken to reduce the variance to the overall budget. In the case of an unexpected underspend, funds will be re-allocated to other departments within Columbia to complete projects or work that may have been scheduled for future periods or work that was on hold pending available funds. If the variance is expected to result in an overspend, costs will be managed tightly within the department and Columbia as a whole to mitigate the identified budget variance.

Q. Does the O&M expense budgeting methodology described in your testimony result in an accurate estimate of expenses to be incurred during the Fully Forecasted Rate Year?

A. Yes. Columbia has experienced a variance of less than 3% to the original O&M budget in four of the last seven years, with the only exceptions being 2011 and 2014, when the variance was approximately 6.5% and 4.5%, respectively. Specifically, in 2011, Columbia experienced larger than budgeted pension contributions. When that factor was normalized, the remaining budget variance for the year was well below 1%. In 2014, the variance to the budget was driven by a few key factors. One factor was that $1.3 million of productivity savings was budgeted to help Columbia achieve the overall budget objective established by management, but this savings was not realized. In addition, NCSC Shared Services costs were higher than expected primarily as a result of IT spend, as significant projects were ramped up. Incentive compensation also drove this variance, as the payout was higher than anticipated due to positive business results. Notably, in six of the last seven years, Columbia has actually overspent the original O&M budget in the ranges noted, which supports the fact that the O&M budget is a conservative approach for ratemaking purposes. In 2015, Columbia underspent the original O&M budget by a margin of 0.63%. Please refer to Exhibit NJDK-1 accompanying this testimony for a comparison of actual results versus the annual original O&M budget for the years 2009 through 2015. Overall, this Exhibit indicates a high level of O&M budgeting accuracy by Columbia and, accordingly, provides a high level of confidence as to the accuracy of the O&M expenses included in the Fully Forecasted Rate Year.

Q. Have you excluded certain cost categories from your comparison?

A. Yes. O&M expenses that are designed to match, or track against, revenues related to specific programs or costs such as gas costs and low-income programs have been excluded. Such revenue matching mechanisms have been previously approved by this Commission, and ensure that there is no impact on net operating income. The accounting treatment generally allows such expenses to be deferred as incurred and reclassified to expense when the recovery of program costs is recorded in revenue. While these O&M expense variances may be material, there is a corresponding offsetting revenue variance. For that reason, I have excluded these expenses from the comparison so as not to distort the accuracy of the budget.

Q. What is meant by the term corporate-level budget?

A. Earlier in my testimony I explained that Columbia's budget for field operating centers and other major business functions is combined with a corporate-level budget to arrive at a total company budget. The corporate-level budget represents categories that are budgeted at a NiSource-level, and not an individual Columbia department level. This allows for each corporate-level department to focus exclusively on the expenditures for which they are directly responsible. Examples of O&M expenses included at the corporate-level are employee benefits, benefits administration fees, audit fees, in-house legal, human resources, corporate insurance, regulatory amortizations, and revenue trackers.

Q. What are the principal assumptions used in the development of the labor cost element for specific department budgets included in the forecasted test period O&M expenses?

A. Labor expense is based on projected headcount and wage increase assumptions. More detailed labor budgets are developed by projecting the year's labor based on a trend analysis. The projection includes estimates for headcount, gross salary, overtime, vacation and sick time, and labor charges in from other departments. This results in a sub-total for total labor dollars available by month, which will then be allocated between O&M accounts, capital, and charges to other departments. That allocation involves developing an estimate for the following year's O&M labor budget based on the projected work by activity, and using the estimate to determine how much of the labor budget should be allocated to O&M accounts. The remaining labor resources are then allocated to capital or charged out to other departments where work may be performed. A final reasonableness check is done to compare the budgeted amount for capital labor against prior year actual charges to ensure the numbers are in line with the most recent results.

Q. Does your budgeting analysis include any projections regarding Columbia headcount?

Yes, Columbia is projecting 660 and 689 active full-time employees for 2016 and 2017 respectively, and an overall wage increase guideline of 3% for exempt and non-exempt employees. Labor costs for bargaining unit employees are based on the contracts currently in place. The headcount is increasing above the ending Historic Test Year level of 632 active full-time employees. These increases are driven by both increases in Field Operations and System Operations to support safety initiatives and ongoing compliance work as well as increases in Engineering and Construction to support the efficient deployment of increased levels of capital associated with Columbia's aggressive infrastructure replacement program.

Q. Please explain how non-labor activities or events are taken into account in the development of the O&M expense budget?

A. Non-labor expenses start with the assumption that amounts are to be held relatively flat year to year reflecting a normal, ongoing level of expenses and further adjusted for incremental activities or events that are reasonably expected to occur.

The Future Test Year and Fully Forecasted Rate Year Outside Services budgets reflect inflationary cost increases associated with the continuation of work activities at historical levels as well as planned incremental work volume in targeted areas.

The targeted areas in the detailed work plan for the Future Test Year include vacuum excavation associated with facility locating and global positioning system ("GPS") remediation, accelerated GPS data collection, corrosion remediation and regulator station maintenance, field assembled riser replacements, and increased inside leak inspections. Incremental funding is included in the Future Test Year for the continued curriculum development in Operator Qualification ("OQ") training.

The work plan for the Fully Forecasted Rate Year, the detail of which will be driven largely by the actual work performed in the Future Test Year and intelligence gathered by Operations personnel on system conditions as they exist going into 2017, includes additional funding for abnormal operating conditions ("AOC") identified during the Future Test Year and leak survey synchronization. Additional funding is allocated for continued training development.

Q. Please describe the basis for the corporate-level budgets described on page 7 and included in Columbia's overall O&M budget.

A. Corporate-level budgets provided to Columbia include several major categories. Employee benefits expenses are based on information provided by NiSource's independent actuary, AON Hewitt. For instance, the pension costs projected in the budget for the rate year are part of the actuarial estimates provided by AON Hewitt. Corporate insurance expenses are based on estimated property and casualty premium costs developed by NiSource's Corporate Insurance Department. Audit fees are based on estimates developed by NiSource Accounting. Telecommunications expenses are based on estimates developed by NiSource Information Technology. NCSC Shared Service expenses are based on estimates of services to be performed by NCSC, NiSource's shared services company, for Columbia, and are included in the NCSC Shared Services budget. This year, that budget has been broken down into two cost elements, NCSC - Shared Services and NCSC - Shared Operations. Please refer to pages 18-19 of Columbia witness Miller's testimony for an explanation of the distinction between these cost elements. Benefits administration fees and incentive plan expenses are based on estimates developed by NiSource Human Resources.

Q. How are the budgets developed for the corporate-level O&M expense budgets?

A. NCSC Shared Services budgets, such as the legal and human resources budgets, are based on the individual budgets developed by each NCSC department. Similar to

Columbia's O&M budgeting methodology, NCSC budgets its O&M expenses by cost categories such as labor, materials, outside services and other expenses. In addition, each NCSC department is allocated a portion of NCSC's indirect costs, such as benefits, taxes, depreciation and other expenses to arrive at a fully loaded cost. The fully loaded corporate-level budget is allocated to Columbia and other NiSource companies through the NCSC Shared Services budget using an allocation basis or bases as determined by each department.

Q. What allocation bases are available to each NCSC department for allocating their budgets to NiSource companies?

A. The direct costs from NCSC departments, as mentioned above, such as labor, materials, outside services and other expenses are allocated based on methods as deemed appropriate by department management. Please refer to Exhibit 4, Schedule 11, Attachment B.

Q. What is the O&M expense level for the Historic Test Year and Fully Forecasted Rate Year?

A. O&M expense before ratemaking adjustments is $132,545,046 for the Historic Test Year ended November 30, 2015, $145,283,000 for the Future Test Year and $153,131,000 for the Fully Forecasted Rate Year ending December 31, 2017, increases of $12,737,954 and $7,848,000 respectively before pro forma ratemaking adjustments.[1]

[1] This testimony compares O&M expenses independent of expense items specifically tracked against revenues as discussed earlier in this Statement.

Q. Please explain the key variances in O&M expense levels between the Historic Test Year and the budgeted amounts for the Future Test Year.

A. Please refer to Exhibit 104, Schedule 1, Page 3, for a breakdown of the O&M expense variances from the Historic Test Year to the budgeted Future Test Year ended November 30, 2016. The methodology for how labor is budgeted has been covered in my earlier testimony. Please refer to Exhibit 104, Schedule 10, Page 1, for an illustration of the $765,766 increase in labor from the normalized Historic Test Year to the budgeted Future Test Year.

Incentive compensation decreases from the Historic Test Year to the Future Test Year, despite the increase in labor, due to the fact that actual financial and key metric results in the Historic Test Year resulted in an incentive compensation payout above the targeted level. The budget for all future years is always calculated at the target level, which creates the year over year decrease from the Historic Test Year to the Future Test Year.

As mentioned previously, the budgeted amount for benefit expenses such as pension, other postemployment benefits ("OPEB") and other benefits, is based on actuarial estimates provided by NiSource's independent actuary AON Hewitt. The change in benefits from the Historic Test Year amount to the Future Test Year budget is driven by a decrease in pension funding partially offset by an increase in Other Employee Benefits, specifically for increases in 401(k) and medical and dental benefit expenditures.

The increase in Outside Services from the Historic Test Year to the Future Test Year, as described earlier in my testimony, is illustrated at Exhibit 104, Schedule 11, Page 1.

Rent and Lease Expense has increased, primarily due to: (1) the anticipated completion of the construction of the training facility and the PA North Operations Center; and (2) the inclusion of a full year of lease payments for the York and New Castle facilities, which were not occupied for the entirety of the Historic Test Year. Please see Exhibit 104, Schedule 12, Page 1, for a breakdown of the increase in rents and leases by location.

The increase in Materials and Supplies expense results from a historical upward trend in spending forecasted out for the Future Test Year, as explained previously. The increase between the historic test year and future test year is partially influenced by the timing of expenditures in those periods.

The other O&M increase reflects utility expenses for new facilities and deferral amortization adjustments.

The increases in NCSC Shared Services and NCSC Shared Operations are explained in detail at Exhibit 104, Schedule 13, Page 1, and Exhibit 104, Schedule 14, Page 1, respectively.

Q. Please explain the key variances in O&M expense levels between the Future Test Year and the budgeted Fully Forecasted Rate Year.

A. Please refer to Exhibit 104, Schedule 1, Page 4, for a breakdown of the O&M expense variances from the Future Test Year to the budgeted Fully Forecasted Rate

Year. The methodology for how labor is budgeted has been covered in my earlier testimony. Please refer to Exhibit 104, Schedule 10, Page 2, for an illustration of the $1.8 million increase in labor from the normalized Future Test Year to the budgeted Fully Forecasted Rate Year.

Incentive compensation increases from the Future Test Year to the Fully Forecasted Rate Year, commensurate with the increase in labor costs.

As mentioned previously, the budgeted amount for benefit expenses, such as pension, OPEB and other benefits, are based on actuarial estimates provided by NiSource's independent actuary AON Hewitt. The change in benefits from the Future Test Year amount to the Fully Forecasted Rate Year budget is driven by a decrease in pension funding partially offset by an increase in Other Employee Benefits, specifically for increases in 401(k) associated with incremental headcount and a projected increase in active medical expense.

The increase in Outside Services from the Future Test Year to the Fully Forecasted Rate Year, as described earlier in my testimony, is illustrated at Exhibit 104, Schedule 11, Page 2.

The decrease in Rent and Lease Expense reflects the expiration of certain facility leases and net changes in monthly lease payments, as illustrated on Exhibit 104, Schedule 12, Page 2.

The decrease in Materials and Supplies expense results from the netting of the historical trend in spending forecasted out for the Future Test Year and the normalization of the timing of expenditures described between the historic and future test years.

The increases in NCSC Shared Services and NCSC Shared Operations are explained in detail at Exhibit 104, Schedule 13, Page 2, and Exhibit 104, Schedule 14, Page 2, respectively.

Q. **Are there any other matters that you would like to address?**

A. Yes. Columbia's case at R-2015-2468056 reflected an adjustment to NCSC – Shared Services expenses to remove the cost of Phantom Stock in the future test year and fully forecasted rate year. There are no such adjustments in this proceeding because Phantom Stock is not included in the future test year or fully forecasted rate year budgets.

Q. **Does this complete your direct testimony?**

A. Yes, it does.

Columbia Gas of Pennsylvania, Inc.
Statement of Operations and Maintenance Expense Budget vs. Actual

CE	Budget 2009	Budget 2010	Budget 2011	Budget 2012	Budget 2013	Budget 2014	Budget 2015
Labor	23,873	23,108	22,910	23,693	25,709	25,251	28,309
Incentive Compensation	293	1,171	1,149	1,249	1,238	1,333	1,584
Pension	2,119	6,005	6,598	-	3	1,137	-
OPEB	715	1,065	492	(154)	(284)	(550)	(1,378)
Other Employee Benefits	5,076	6,363	6,509	6,184	6,454	4,584	4,791
Outside Services	15,636	15,175	13,094	12,123	12,104	22,311	26,079
Rent and Leases	1,314	1,374	1,458	1,615	1,887	2,273	4,791
Corporate Insurance	3,116	3,574	3,413	3,048	3,004	3,087	4,516
Injuries and Damages	1,209	944	795	630	630	500	500
Employee Expenses	1,109	1,046	1,163	1,142	1,295	1,305	1,640
Company Memberships	347	345	249	292	262	256	256
Utilities and Fuel Used in Company Operations	675	570	567	503	1,167	1,303	1,310
Advertising	500	185	170	170	470	170	170
Fleet	4,663	4,104	4,421	5,046	5,452	5,708	5,728
Materials & Supplies	4,929	4,767	4,775	4,899	4,649	5,024	5,067
Other O&M	(3,987)	(3,780)	(116)	(783)	60	(1,906)	(434)
PUC, OCA, OSBA Fees	1,673	1,953	1,354	1,454	1,699	1,583	2,161
NCSC Shared Services & NGD Shared Operations	31,889	38,399	37,740	39,742	44,597	47,962	49,533
Amortization	82	75	(243)	(1,446)	(1,455)	185	267
Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-
Total Operation and Maintenance Expense Before	95,231	106,443	106,498	99,407	108,941	121,516	134,890

CE	Actuals 2009	Actuals 2010	Actuals 2011	Actuals 2012	Actuals 2013	Actuals 2014	Actuals 2015
Labor	23,153	23,577	22,845	23,996	25,124	25,818	27,980
Incentive Compensation	1,303	1,628	1,649	1,690	1,845	1,816	1,791
Pension	392	5,799	13,088	91	2,489	1,131	14
OPEB	1,683	775	(213)	88	(454)	(1,298)	(1,336)
Other Employee Benefits	4,995	7,472	6,210	5,880	5,635	5,432	5,992
Outside Services	15,180	15,440	13,244	12,133	14,113	22,070	22,951
Rent and Leases	1,306	1,207	1,348	1,485	1,699	1,699	2,252
Corporate Insurance	3,045	3,241	2,926	2,763	2,734	2,796	2,899
Injuries and Damages	605	545	340	241	305	(185)	381
Employee Expenses	1,405	1,450	1,553	1,465	1,376	1,264	1,415
Company Memberships	295	250	293	262	249	313	479
Utilities and Fuel Used in Company Operations	451	417	487	1,094	1,247	1,244	1,287
Advertising	389	281	167	133	243	236	207
Fleet	4,650	4,726	5,092	5,357	5,780	6,106	5,956
Materials & Supplies	4,741	4,967	4,412	4,353	5,171	5,343	5,873
Other O&M	(3,527)	(3,005)	157	(63)	31	512	306
PUC, OCA, OSBA Fees	1,721	1,539	1,348	1,523	1,585	1,815	2,161
NCSC Shared Services & NGD Shared Operations	34,023	36,457	38,899	40,164	43,374	50,760	53,169
Amortization	82	0	(489)	(1,446)	(594)	185	267
Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-
Total Operation and Maintenance Expense Before	95,892	106,766	113,356	101,209	111,952	127,057	134,044

CE	Variance 2009	Variance 2010	Variance 2011	Variance 2012	Variance 2013	Variance 2014	Variance 2015
Labor	(720)	469	(65)	303	(585)	567	(329)
Incentive Compensation	1,010	457	500	441	607	484	207
Pension	(1,727)	(206)	6,490	91	2,486	(6)	14
OPEB	968	(290)	(705)	242	(170)	(748)	42
Other Employee Benefits	(81)	1,109	(299)	(304)	(819)	848	1,201
Outside Services	(456)	265	150	10	2,009	(241)	(3,128)
Rent and Leases	(8)	(167)	(110)	(130)	(188)	(574)	(2,539)
Corporate Insurance	(71)	(333)	(487)	(285)	(270)	(291)	(1,617)
Injuries and Damages	(604)	(399)	(455)	(389)	(325)	(685)	(119)
Employee Expenses	296	404	390	323	81	(41)	(225)
Company Memberships	(52)	(95)	44	(30)	(13)	57	223
Utilities and Fuel Used in Company Operations	(224)	(153)	(80)	591	80	(59)	(23)
Advertising	(111)	96	(3)	(37)	(227)	66	37
Fleet	(13)	622	671	311	328	398	228
Materials & Supplies	(188)	200	(363)	(546)	522	319	806
Other O&M	460	774	272	720	(29)	2,418	740
PUC, OCA, OSBA Fees	48	(413)	(5)	69	(114)	232	-
NCSC Shared Services & NGD Shared Operations	2,134	(1,942)	1,159	422	(1,223)	2,798	3,636
Amortization	(0)	(74)	(246)	(0)	861	-	-
Lobbying (Amount included in above Cost Elements)	-	-	-	-	-	-	-
Total Operation and Maintenance Expense Before	661	324	6,858	1,802	3,011	5,542	(846)

COLUMBIA STATEMENT NO. 10

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
vs.	)	Docket No. R-2016-2529660
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
PANPILAS W. FISCHER
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

Q. Please state your name and business address.

A. My name is Panpilas W. Fischer. My business address is 290 W. Nationwide Blvd., Columbus, Ohio 43215.

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

A. I am employed by NiSource Corporate Services Company ("NCSC"), a management and services subsidiary of NiSource Inc. ("NiSource"). My current title is Tax Director at NCSC.

Q. Please briefly describe your professional experience.

A. I began my career with KPMG as a staff auditor in 1987. I then joined the firm of Clark, Schaefer, Hackett and Co., CPAs, as a Senior Auditor in 1989 where I performed financial audits, reviews and compilations, and prepared and reviewed tax returns for corporations, partnerships, and individuals. In October 2000, I started working as a tax analyst for NCSC and assumed various roles in the tax department. In October 2015, I was promoted to my current position.

Q. Please describe your educational background.

A. I received a Bachelor of Business Administration in Accounting in 1987 from The Ohio State University. I am a Certified Public Accountant and member of the Ohio Society of Certified Public Accountants.

Q. What are your responsibilities in your current position?

A. In my current position with NCSC, my principal responsibilities include supervision and preparation of all of Columbia Gas of Pennsylvania, Inc.'s ("Columbia" or "the Company") income tax activities including the booking of income tax accruals and deferred tax entries, the filing of income tax returns, tax research and planning and the preparation of income tax data and related testimony for rate proceedings.

Q. Have you previously testified before this or any other regulatory agency?

A. I have previously provided testimony to the Pennsylvania Public Utility Commission ("Commission"), the Kentucky Public Service Commission, the Public Utilities Commission of Ohio, the Public Service Commission of Maryland and the Commonwealth of Virginia State Corporation Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The primary purpose of my testimony is to present and support Columbia's income tax and other tax expense included in the cost of service. The filing includes federal and state income tax recovery, reduction of rate base for deferred income taxes, as well as a reduction to tax expense resulting from the Company's 2008 change in tax method of accounting for repairs. The income tax calculations are included in Exhibit 7 for the Historic Test Year (the twelve month period ending November 30 2015) and Exhibit 107 for the Future Test Year (the twelve month period ending November 30, 2016) and Fully Forecasted Rate Year (the twelve-month period ending December 31, 2017). Taxes other than income tax are included in Exhibit 6 and Exhibit 106.

Q. Will you explain the basis for the income tax calculations for the Historic Test Year?

A. The tax calculations were made in accordance with federal and state laws. The federal tax rate is 35% and the Pennsylvania tax rate is 9.99%. The Historic Test

Year tax calculations have been impacted by certain items that have been historically treated as flow-through or deferred in rate making proceedings.

Q. Can you explain the flow-through items included in the tax provision?

A. Prior to 1981, federal tax statutes did not require full normalization of accelerated tax depreciation versus book straight line depreciation recovered in rates. Beginning in 1981 for Columbia, normalization, under the Internal Revenue Code, does not permit the flow-through or refund of accelerated depreciation benefits by a utility to its customers. Such benefits must be provided for in a deferred tax reserve, and that reserve may be allowed as a rate base reduction. Prior to 1984, the Company flowed-through the benefits of accelerated depreciation for vintage years prior to 1981. Beginning in 1984, the Company began to normalize the remaining book versus tax differences on Asset Depreciation Range vintages (1971 through 1980) based upon the Commission's order in Docket No. R-832493. For the Historic Test Year, we are in a position where the Company has very little in terms of tax depreciation remaining on pre-1981 assets. Thus, we are in a turnaround position, since book depreciation is now higher than tax depreciation.

In addition, the Company has excess deferred taxes that were originally computed at a 46% federal tax rate for 1981-1987 vintages that are being refunded in rates under the Average Rate Assumption Method ("ARAM"). This method required the Company to keep deferred taxes intact until book depreciation exceeds tax depreciation for those vintage years, and to flow back the deferred tax excess between the 46% rate and the current 35%. Since most of the property was 15 year property for federal purposes, the excess is in a turnaround situation. The company projects to record lower tax expense by $89,482 in its federal tax provision related to the excess deferred taxes for the Fully Forecasted Rate Year.

Q. How is Columbia handling the reduction in tax caused by the 2008 change in method of accounting for repairs?

A. As agreed in the settlement of Columbia's 2010 rate case (Docket No. R-2009-2149262), a refund of the $37,487,634 is being made to customers, which reflects the cash benefit received in 2009 for the tax year 2008 method change. As of December 31, 2014, a total of $35,442,920 was amortized as agreed in the settlement of Columbia's 2012 rate case (Docket No. R-2012-2321748) and an additional $2,044,714 is being amortized through the period ended December 31, 2016, as agreed in the settlement of Columbia's 2014 rate case (Docket No. R-2014-2406274), which leaves a remaining unamortized balance at December 31, 2015 of $681,571. This case reflects the remaining $681,571 as of December 31, 2015 being amortized over 12 months in the Future Test Year which represents a full amortization of the refund by the beginning of the Fully Forecasted Rate Year. As provided in the 2010 Rate Case settlement, the amortization is without interest and without a deduction of the unamortized balance from rate base.

Q. How does the change in method impact Columbia's taxable income going forward?

A. For a period of time, the repairs deduction is anticipated to exceed deductions if the plant had been capitalized for tax purposes, and thus will continue to result in a reduction to taxable income. However, beginning post October 18, 2011 (the effective date of Columbia's 2010 rate case) the repairs deduction is being normalized under deferred tax accounting, so there will be no impact on total federal tax expense.

Q. Are there any other items treated as flow-through in the rate-making process?

A. Yes. The Company continues to reduce its income tax allowance for the net cost of retirements, which is allowed as a deduction on its tax return. In addition, there are three permanent differences included in the tax provision. Permanent differences are items of income or expense that will never be included in the federal tax return. Items increasing tax expense as a result of being non-deductible include expenses for a portion of business meals, employee stock purchase plan compensation, and a portion of lease expense on vehicles.

Q. How has the Company handled Pennsylvania Corporate Net Income Taxes in its calculation of deferred income taxes for depreciation?

A. The Company, based on prior Commission orders, has not normalized deferred state income taxes. The Company continues to flow-through the state income tax benefits of accelerated depreciation on its book depreciable assets. I note that the Company is not permitted to claim the benefit of bonus depreciation deductions in the test years, and adjusts federal accelerated tax deductions in future years for disallowed bonus depreciation.

Q. Did the Company receive a refund from Pennsylvania for the change in method?

A. No. The Company had a $145.0 million net operating loss for 2008 that it carried forward into 2009 and will carry forward into future years. The Company reduced its Pennsylvania taxable income by 15% of taxable income in 2009. The Company also had a $3.7 million net operating loss for 2010 and a $69.7 million net operating loss for 2011 that is being carried forward. For tax years in 2015 and thereafter, the Company is permitted to use the loss carryforward as a state income tax deduction equal to the higher of $5,000,000 or 30% of taxable income. The Company's claimed tax expense takes such benefit into account.

Q. Are you aware of any changes that could impact the utilization of the Pennsylvania net operating loss?

A. Yes, in a recent ruling, the Commonwealth Court of Pennsylvania found in favor of a taxpayer who challenged the statutory limitations on the use of the net loss carryforward discussed above, on the grounds that it violates the uniformity requirement of the Pennsylvania Constitution (Uniformity Clause).[1] I have been advised by counsel that this case will likely be appealed by the Commonwealth and reviewed by the Pennsylvania Supreme Court. Pending a decision from the Pennsylvania Supreme Court, the Company will continue to apply the loss carryforward limitation in its calculation of state income tax expense and, as stated previously, has taken the loss carryforward limitation into account in the calculation of the Company's claimed tax expense in this case.

Q. Was a Consolidated Tax Adjustment included in the claim in this case?

A. Similar to the Company's 2015 base rate case, a Consolidated Tax Adjustment was not included in this case, because Columbia was a loss company on average for the three year period 2012-2014. The loss is the result of 50-100% bonus depreciation

[1] Nextel Communications of the Mid-Atlantic, Inc., v. Commonwealth of Pennsylvania, 129 A.3d 1 (Pa. Commw. 2015).

allowed under federal tax law (the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, the American Taxpayer Relief Act of 2012 and the Tax Increase Prevention Act of 2014). Additional federal tax law, The Protecting Americans from Tax Hikes Act of 2015, extended 50% bonus depreciation for most assets placed in service during the Historic Test Year. Under these circumstances, it is appropriate not to apply a consolidated income tax adjustment in this case. Nevertheless, I have provided details of the income and losses of affiliated companies for the three year period in Exhibit No. 7, pages 2 through 4.

Q. Are there other reasons why a consolidated tax adjustment is not appropriate?

A. Yes, most of the "tax loss" generated by the NiSource system is the result of tax deductions generated by debt issued to finance the acquisition of Columbia Energy Group. As shown on Exhibit No. 7, pages 3 and 4, over $187 million of the $260 million of average annual losses for unregulated companies, arises from this debt, which is recorded as a loss for NiSource Inc. The cost of this debt is not reflected in Columbia's rates and the debt does not finance rate base. Since the debt cost associated with those incremental investments outside of the rate base is not reflected in Columbia's rates to customers, it is not appropriate to provide the tax deductions associated with such cost to ratepayers.

Q. Can you summarize the impact of your testimony on historic and proposed income tax expense?

A. Yes, for the Historic Test Year, page 19 of Exhibit 7 delineates total pro forma tax expense of $46,897,546. This total includes $5,057,356 of state income taxes, which is based on $148,889,113 of operating income less $28,023,975 of interest expense on debt for total pre-tax income of $120,865,138, resulting in an effective state income tax rate of 4.18%. This reduced expense, as compared to the Pennsylvania statutory rate of 9.99%, is a result of the flow through treatment of accelerated depreciation deductions and loss carryforward deductions for state income tax purposes. The expense for federal income taxes is $41,840,190 or 34.62%, of the pre-tax income less state income taxes. This 34.62% expense is .38% less than the federal statutory rate of 35%. The difference is largely attributable to the tax repairs refund amortization being flowed through in rates.

Q. Please continue with respect to the Fully Forecasted Rate Year.

A. For the proposed income tax recovery, the amounts can be found on Exhibit 107, pages 16 and 17. The same individual items creating a variance from statutory rates in the historical data, create a variance in proposed rates. Minor adjustments have been made to reflect forecasted numbers during the Fully Forecasted Rate Year.

Q. How have taxes impacted the Company's rate base?

A. Exhibit 107, page 5, delineates the reduction in rate base for deferred income taxes. The amounts include deferred taxes on net utility plant that have or will be normalized by the end of the Fully Forecasted Rate Year, as well as deferred taxes on inventory and customer advances.

Q. How has the deduction for 263A mixed service costs impacted deferred taxes in rate base?

A. As agreed in the settlement of Columbia's 2012 rate case (R-2012-2321748), the Company has been given permission to normalize this deduction for federal income taxes and treat the deferred taxes as a reduction to rate base. The adjustment can be found on Exhibit 107, page 9, line 18.

Q. Is there an inclusion of deferred taxes for the Federal Net Operating Loss in rate base?

A. In the Historic Test Year, the deferred tax asset for the Federal Net Operating Loss, which represents the remaining balance of un-utilized net operating loss, is $17,952,226 as shown in Exhibit 7, page 9. The Company has experienced net taxable losses for the years 2010, 2011, 2012, and 2013 as a result of taking deductions for 50-100% bonus depreciation, resulting in the deferred tax asset being recorded for the un-utilized net operating losses. 50% bonus depreciation deductions were taken in 2010, 2012, and 2013 and 100% bonus depreciation deductions were taken in 2011 as permitted under tax laws in effect per my testimony on page 7. In 2014, the Tax Increase Prevention Act of 2014 extended 50% bonus depreciation to assets placed in service in 2014 and, in 2015, the Protecting Americans Against Tax Hikes Act of 2015 extended bonus depreciation another 5 years with 50% bonus depreciation for assets placed in service in 2015, 2016, and 2017, 40% bonus depreciation for assets placed in service in 2018 and 30% bonus depreciation for assets placed in service in 2019, thereby extending the time when the net operating loss will be utilized. The deferred tax asset represents the cash benefits the Company has not received because of the net operating losses. The deferred tax asset is included in rate base because the Company cannot reflect an increase in deferred taxes for tax depreciation deductions that have not been realized. To do so would violate the principles of the normalization requirements under the Internal Revenue Code. Past IRS rulings addressing this issue have made it clear that companies cannot reduce rate base for benefits that have not been realized. The deferred tax asset for the un-utilized net operating losses will increase throughout 2017, as bonus depreciation legislation has been enacted for assets placed in service through 2019. Due to the net operating losses generated by bonus depreciation deductions in the aforementioned years, the expectation is that the Company will not utilize all of its net operating losses until the end of 2022. Therefore, there is an increase to rate base on Exhibit 107, Page 5, of $31,150,831, as a deferred tax asset for the amount of unutilized net operating loss for the Fully Forecasted Rate Year.

Q. Please explain the adjustment to deferred taxes for the Fully Forecasted Rate Year on Exhibit 107, Page 5.

A. Whenever there are estimated changes in the deferred taxes that occur in a future rate period, the Normalization requirements of the Internal Revenue Code require that the deferred taxes be reflected on a pro rata basis as provided under Reg. Section 1.167(l)-1(h)(6)(ii). A future test period is defined as that portion of the test period after the effective date of the rate order. Under the pro rata basis, the change in the deferred taxes is determined by multiplying the change by a fraction of the number of days remaining in the period at the time such change is to be accrued over the total number of days in the future period. Applying this calculation resulted in a decrease to deferred taxes of $30,921,471.

Q. Are you sponsoring any other expense adjustments?

A. Yes. I am also sponsoring adjustments for Federal Insurance Contribution Act ("FICA") Tax, Property Tax, Capital Stock Tax and License and Franchise Tax. These adjustments are delineated on Exhibits 6 and 106.

Q. Please explain the FICA adjustment.

A. The adjustment represents an increase in FICA taxes as they apply to the payroll adjustments discussed in Company witness Miller's testimony (Columbia Statement No. 4). An increase in payroll taxes of $97,409 is reflected in the annualized Historic Test Year. Please see Exhibit No. 6, Schedule 2, Page 3 of 5 for the calculation. For the Fully Forecasted Rate Year, the Company is projecting a higher payroll base, thus increasing payroll taxes by $137,620. Please see Exhibit No. 106, Schedule 2, Page 3 of 5 for the calculation.

Q. Please explain the property tax adjustment.

A. The PURTA tax and the locally assessed property tax on Pennsylvania property are both consistent with the most recent year-end tax levels as of December 31, 2014. The West Virginia tax for gas stored underground was developed using the December 31, 2014 assessed value and the 2014 tax rate. This annualized level of $580,697 is higher than the Historic Test Year level of $550,626, as shown on Exhibit 6, Schedule 2, Page 4 of 5, resulting in an upward adjustment of $30,071. The detail supporting this calculation for the Fully Forecasted Rate Year is provided on Exhibit 106, Schedule 2, Page 4 of 5. The pro forma Fully Forecasted Rate Year reflects a downward adjustment of $117,338 from the annualized level as a result of using the December 31, 2015 assessed value and the 2014 tax rate which is the latest available at this time.

Q. Please explain the Capital Stock tax adjustment.

A. Similar to the property tax adjustment, the capital stock tax adjustment begins with the last known basis as of December 31, 2014. To this end, the 2015 rate was applied, resulting in a $24,219 downward adjustment from the Historic Test Year level. The major reason for the adjustment downward is the rate decrease due to the phase out of the Pennsylvania Capital Stock Tax. The capital stock tax for the pro-forma Fully Forecasted Rate Year ending December 31, 2017 is $0 using a rate of .000 because, under current legislation, the capital stock tax is completely phased out by the end of 2016. This represents a downward adjustment of $206,485 from the annualized level of $206,485.

Q. Please explain the License and Franchise Tax adjustment.

A. The License and Franchise tax annualized level of $7,343 is the same as the Historic Test Year level. This amount reflects the latest West Virginia franchise tax liability for the Company. The pro forma Fully Forecasted Rate Year was not adjusted from this level.

Q. Please explain the Other Tax adjustment on Exhibit 106, Schedule 2, Page 2.

A. Other taxes are primarily comprised of excise tax. The annualized level of $8,749 was not adjusted for the Historic Test Year. The pro forma Fully Forecasted Rate Year was also not adjusted from this level.

Q. Does this conclude your testimony?

A. Yes.

COLUMBIA STATEMENT NO. 11

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
vs.	)	Docket No. R-2016-2529660
	)	
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
MARK BALMERT
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

Q. Please state your name and business address.

A. Mark Balmert, my business address is 290 West Nationwide Boulevard, Columbus, Ohio 43215.

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

A. I am Director of Regulatory Strategy & Support for NiSource Corporate Services Company ("NCSC"). NCSC provides, among other services, accounting and regulatory-related services for the subsidiaries of NiSource Inc. ("NiSource"). I am testifying on behalf of Columbia Gas of Pennsylvania, Inc. ("Columbia" or the "Company"), which is one of the NiSource local distribution companies.

Q. What are your responsibilities?

A. My section within NCSC is responsible for the preparation and support of special regulatory studies, such as allocated cost of service ("ACOS") studies, lead lag studies, revenue development, and rate design in support of rate proceedings for the six NiSource Gas Distribution Companies, which consist of Columbia Gas of Maryland, Columbia Gas of Kentucky, Bay State Gas Company (d/b/a Columbia Gas of Massachusetts), Columbia Gas of Ohio, Columbia Gas of Pennsylvania, and Columbia Gas of Virginia.

Q. What is your educational and professional background?

A. I graduated from The Ohio State University in June of 1979, earning a Bachelor of Science Degree in Business Administration with a major in accounting. I have been employed by various entities within the Columbia Energy Group and its successor, NiSource, in capacities related to rates, regulatory accounting and compliance, and information technology applications since October 1979. In February of 2012, I was named Directory of Regulatory Strategy & Support for NCSC, which is the position I currently hold.

Q. Have you previously testified before this Commission?

A. Yes. I have testified before this Commission as well as the Public Utilities Commission of Ohio, the Virginia State Corporation Commission, the New Hampshire Public Utilities Commission, the Kentucky Public Service Commission, the Public Service Commission of Maryland and the Massachusetts Department of Public Utilities.

Q. What is the purpose of your testimony in this proceeding?

A. I am sponsoring Columbia's ACOS studies in this matter. As required by Section 53.53 III, Items 1 and 9 of the Commission's regulations, I prepared ACOS studies by rate class at present and proposed rates (Item 1) and a cost analysis supporting minimum charges for all rate schedules (Item 9). The studies and cost analysis are presented in Exhibit 111. Item 10 of Section 53.53 III requires a cost analysis supporting demand charges. I did not prepare a cost analysis for demand charges because Columbia's present and proposed tariffs do not contain distribution demand charges.

Q. Please describe Exhibit No. 11.

A. Exhibit No. 11 addresses the Commission's filing requirements regarding ACOS studies and rate design as required by Section 53.53 III. The Company's ACOS studies are presented in Exhibit No. 111 and a detailed description of the methodologies are included in this testimony. The ACOS studies are based on the fully forecasted rate year ending December 31, 2017.

Q. Are you responsible for the ACOS studies presented in Exhibit No. 111?

A. Yes, I am.

Q. Three ACOS studies are included in Exhibit No. 111. Is that correct?

A. Yes.

Q. Why did you conduct three ACOS studies?

A. Columbia has filed two studies in its base rate proceedings since the early 1980s that provide the outside limits of the possible allocations of mains to the various classes of service. The customer-demand study (Exhibit No. 111, Schedule 1) produces results that are generally more favorable to the industrial class while the peak and average study (Exhibit No. 111, Schedule 2) produces results that are generally more favorable to the residential class. Columbia recognizes that no one cost of service study is the "right" study and in the past believed the results of two such studies provided a reasonable range of returns for use as a guide in establishing appropriate rates.

Q. What is the basis of the third study and why did Columbia file it?

A. The third study, as presented in Exhibit No. 111, Schedule 3, is an average of the customer-demand study and the peak and average study. Columbia continues to believe that the customer-demand study and the peak and average study provide a reasonable range, and that the average study with its equal weighting of the two studies, provides the Company, the parties and the Commission with a set of returns that can be used as a benchmark or guide in revenue allocation. The average study is another tool that is used in setting rates based on the cost to serve.

Q. Could you provide a list of the schedules, and attachments you are sponsoring through your testimony?

A. Yes. For purposes of clarity, the table below lists all the schedules and attachments that I am sponsoring.

Schedule/Attachment	Description
Exh. No. 111, Schedule No. 1	Customer-Demand Study
Exh. No. 111, Schedule No. 2	Peak & Average Study
Exh. No. 111, Schedule No. 3	Average Study
Statement No. 11, Exhibit MPB-1	Development of Allocation Factors
Statement No. 11, Exhibit MPB-2	Calculation of Allocation Factors
Statement No. 11, Exhibit MPB-3	Factor Selection and Rationale
Statement No. 11, Exhibit MPB-4	Intra-Class Adjustment of Storage Carrying Costs

Q. Could you briefly describe the format of the ACOS studies that you are sponsoring?

A. The format is generally identical for the three studies except for the customer-demand study, Schedule No. 1. It contains 30 pages, while the peak and average study in Schedule 2 and the average study in Schedule 3 each contain 13 pages. The customer-demand study contains the customer charge studies, which I will be discussing later in my testimony, on pages 14 through 30 of Schedule No. 1. The rates of return that are shown on page 1 of each study are based on income generated using proposed rates, with page 2 showing the rates of return generated using current rates. Both page 1 and page 2 summarize the same allocated cost of service with the exception of income taxes and uncollectibles, which vary with the changes in revenue as a result of the change in current rates to proposed rates. The allocation of gross plant investment is shown on page 3, while page 4 contains the reserve for depreciation and page 5 contains depreciation and amortization expenses. Revenue by account and rate schedule is summarized on page 6 for both current and proposed rates and pages 7 and 8 contain the allocation for operation and maintenance ("O&M") expenses, while page 9 contains the allocation of taxes other than income. Rate base is detailed by rate schedule on page 10, with page 11 calculating Federal and Corporate Net Income taxes. The allocation factors are listed on pages 12 and 13.

Q. How were the rate schedules grouped in allocating the cost of service?

A. For residential and small general service, sales and delivery services were combined, respectively; Residential Sales Service ("RSS") and Residential Distribution Service ("RDS") were combined and presented in Column D of each study, and Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD") and Small General Distribution Service ("SGDS") were combined and presented in Column E of each study for Commercial and Industrial customers whose annual usage is less than 6,440 therms. Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD") and Small General Distribution Service ("SGDS") were combined and presented in Column F of each study for Commercial and Industrial customers whose annual usage is greater than 6,440 therms but less than 64,400 therms. Because essentially any customer can qualify and, therefore, switch between sales and distribution services under these schedules, it is reasonable to conclude that customer characteristics are the same for both types of services, i.e., size, consumption patterns, heat sensitive, human need requirement, etc. with no long term difference in the customers' profiles, the distribution cost to provide such service to these customers is the same whether the customer is a sales customer or distribution customer. For the larger customers, the studies present the cost of service for each rate schedule: Small Distribution Service and the lower band of Large General Sales Service ("SDS/LGSS") is presented in Column G of each study for Commercial and Industrial customers whose annual usage is greater than 64,400 therms but less than 540,000 therms, and Large Distribution Service and the upper band of Large General Sales Service ("LDS/LGSS") is presented in Column H of each study for Commercial and Industrial customers whose annual usage is greater than 540,000 therms. Main Line Sales Service ("MLS") and Main Line Distribution Service ("MLDS") are combined and presented in Column I due to their unique characteristic of proximity to an interstate pipeline.

Q. How were Total Company O&M expenses determined by FERC account in the allocated cost of service studies?

A. O&M expenses for the fully forecasted rate year presented in Exhibit 104 were based on cost element data, i.e., labor, benefits, insurance, etc. The allocated cost of service studies spreadsheets submitted in response to standard data request no. GAS-COS-008 show a conversion of the forecasted O&M by description (cost element) to the FERC account, based on allocation percentages representative of the historic test year data (twelve months ending November 30, 2015).

Q. What method did Columbia use in previous cases to identify and separate Account 376 – Mains before allocation to the rate classes in each study?

A. Before its 2012 rate case (Docket No. R-2012-2321748), Columbia did not identify and separate mains before applying allocation factors beyond identifying and separating mains directly assigned to the MLS/MLDS class. Beginning with the 2012 rate case, the Company separated the low pressure and two inch (2") mains and allocating those mains to only the residential and SGS/SGDS class. Columbia recognized that the remaining rate classes were not physically served from those systems, did not benefit from those systems, and therefore should not share in the recovery of those systems' costs. Columbia recognized that the remaining intermediate pressure ("IP"), medium pressure ("MP") and high pressure ("HP") systems greater than two inches may or may not be required to serve those customers served directly from a low pressure system. Without a detailed analysis of each of Columbia's IP, MP, and HP systems, the Company did not know which customers were served from those systems and, therefore, Columbia allocated the IP, MP, and HP systems as it had in previous rate cases, to all rate classes except the MLS/MLDS class. In its 2014 rate case (Docket No. R-2014-2406274) and its 2015 rate case (Docket No. R-2015-2468056), Columbia performed a detailed analysis of each of its IP, MP, and HP systems, in order to allocate the cost of those systems to the customers who used them.

Q. Have you again performed a detailed analysis of each of Columbia's IP, MP, and HP systems in this case?

A. Yes. In this case, as in the 2014 and 2015 rate case, a detailed analysis of each of the Company's IP, MP, and HP systems was performed, resulting in a refined mains allocation method. After identifying and directly assigning the actual inventory of mains for the MLS/MLDS rate class, Columbia is again assigning its remaining mains to one of four allocation categories: "transmission", "low pressure", "regulated non-low pressure", and "remaining regulated pressure." Each of these groupings of mains is then being separately allocated using Columbia's traditional allocation methods.

Q. How has Columbia identified and separated Account 376 – Mains in its current rate case?

A. Using the same method that Columbia used in the 2014 and 2015 rate cases, Columbia identified and separated, based on operating pressures, its transmission, low pressure, and regulated non-low pressure mains. The physical system data was then analyzed alongside the Company's plant accounting system records and its customer billing system ("DIS") records, resulting in a refined and more precise study than was filed in the 2012 rate case. Those specific categories of mains were identified and gathered in response to suggestions received from other parties in Columbia's 2012 rate case. A fourth category, remaining regulated pressure mains, was arrived at by subtracting, from the company totals (excluding direct assignment MLS/MLDS), the quantities separately identified as 'transmission',' low pressure', or 'regulated non-low pressure'. The residual was, by default, 'remaining regulated pressure mains.' This fourth category represents upstream mains that serve both regulated pressure and low pressure customers.

Q. Did Columbia change its allocation method for Account 376 – Mains in its current case?

A. No. As in its 2014 and 2015 cases, Columbia's allocation method in its current case follows the same approach. That is, Peak & Average, Customer/Demand, and Average Studies were prepared, incorporating the same allocation factor drivers (i.e., design day volumes, customer counts, throughput) as were used in Columbia's prior two cases. Again, because Columbia is using the mains allocation method from its 2014 and 2015 cases, which contains the more precise data that was provided by the company's systems and engineers, for the transmission, low pressure, and regulated non-low pressure categories, the costs continue to be allocated to the specific types of customers who utilize those mains. The specific allocation methods used for each of these categories are later explained in my testimony.

Q. What allocation approach is being applied to 'transmission' mains?

A. In both the Customer-Demand (Exhibit 111, Schedule No. 1) and the Peak & Average (Exhibit 111, Schedule No. 2) studies, transmission mains, because they are generally not designed to serve individual or small groups of customers, are typically viewed as being designed to meet the peak demand of the entire geographical area which they serve. For this reason, transmission mains are being allocated using the Company's total design day volumes (excluding MLS/MLDS).

Q. What allocation approach is being applied to 'low pressure' mains?

A. In the Customer-Demand Study, low pressure mains were split into customer and demand components, based on the average cost per foot of a two-inch main. The customer component was calculated by dividing the hypothetical cost of the Company's two-inch low pressure system into the total cost of the Company's low pressure system. This customer component of the low pressure mains was then allocated to rate classes based on the total number of customers (by rate class) served from Columbia's low pressure mains (excluding MLS/MLDS). The demand component was arrived at by calculating the cost of mains, other than the hypothetical cost of the Company's two-inch low pressure systems, and dividing that result into the total cost of the low pressure systems. The demand portion was allocated to rate classes based on the design day volumes for customers served from Columbia's low pressure mains.

In the Peak & Average Study, low pressure mains were allocated using historical test-year throughput volumes applicable only to the low pressure customers (excluding MLS/MLDS), and design day volumes applicable only to the low pressure customers (excluding MLS/MLDS), and weighing each of the volumes equally.

Q. What are "regulated non-low pressure" mains?

A. Regulated non-low pressure mains are IP, MP and HP systems that do not serve low pressure systems. Customers served from regulated non-low pressure mains do not receive any gas directly or indirectly from a low pressure system. Conversely, customers served from low pressure system mains do not receive any gas directly or indirectly from a regulated non-low pressure system.

Q. What allocation approach is being applied to the regulated non-low pressure mains?

A. In the Customer-Demand Study and as with the low pressure mains, the regulated non-low pressure mains were split into customer and demand components and then allocated to the rate classes, using the same methodology. That is, only the customer counts and design day volumes for Columbia's regulated non-low pressure customers were used in the allocation process.

Similarly, in the Peak & Average Study, the regulated non-low pressure mains were allocated using average throughput volumes (based on historical test-year throughput volumes) and design day volumes (both applicable only to the regulated non-low pressure customers and excluding MLS/MLDS), and weighing each of the volumes equally.

Q. What are "remaining regulated pressure" mains?

A. Remaining regulated mains are IP, MP and HP systems that serve two purposes: 1) to deliver gas to customers that require IP, MP or HP pressure; and 2) to also deliver gas into downstream low pressure systems and regulated non-low pressure systems. Because these upstream distribution mains are required to serve customers directly tied to both downstream low pressure and regulated non-low pressure systems, Columbia allocates the costs of remaining regulated pressure mains to all customers (except MLS/MLDS customers, which are directly assigned).

Q. What allocation approach is being applied to the remaining regulated pressure mains?

A. For the Customer-Demand Study, as with the low pressure and the regulated non-low pressure mains, the remaining regulated pressure mains were split into customer and demand components, using the same methodology as previously discussed. However, for these mains, total company (excluding MLS/MLDS) customer counts and design day volumes were used to allocate the mains cost to the rate classes.

For the Peak & Average Study, the same 50-50 split was used to allocate the total mains cost based upon historical test year throughput and design day volumes. However, for this allocation, total Company volumes (throughput and design day) were used. Again, for this allocation, the MLS/MLDS class volumes were excluded from the allocation factor because this class is directly assigned.

Q. How was the demand component for each class determined?

A. The demand component by class was provided by NCSC's Commercial Operations Department and represents expected requirements under design day conditions. I note that the calculation reflects design day total requirement, and thus assumes suppliers will make deliveries necessary to meet customer requirements.

Q. Why were the MLS/MLDS customer groups excluded from the above described allocations of mains?

A. Customers served under rate schedules MLS/MLDS were excluded from the allocations of mains under all studies because these customers are served directly from a Columbia Gas Transmission, LLC ("Columbia Transmission") interstate pipeline or are in close proximity to a Columbia Transmission interstate pipeline. Accordingly, Columbia has little or no main investment associated with providing service to these customers. An inventory of the mains investment in serving these customers was made by studying the Company's plant records and maps on a customer by customer basis. The mains investment cost was then directly assigned to MLS/MLDS. Therefore, it is appropriate to exclude them from the allocation of mains and mains related cost.

Q. Since a significant portion of the Company's investment and expense is related to mains and services does the allocation of those items significantly impact the studies?

A. Yes, it does. Mains and services account for approximately 88% of the Company's gross plant investment and approximately 20% of operating and maintenance expenses, excluding gas costs. The allocation of these items significantly influences the outcome of the studies. In addition, many other elements of operation and maintenance expenses are allocated on plant-related factors.

Q. How are purchased gas costs allocated in the studies?

A. Gas costs are directly assigned to each class at the pro forma levels determined by Company witness Bell (Columbia Statement No. 3) in her Exhibit No. 103, Schedule No.1, Pages 13 through 18.

Q. Were there any other major O&M expense items that you directly assigned?

A. Yes. As shown on Page 8, Lines 8 and 15 of all three studies, I assigned recovery of costs from the Company's Universal Services Program ("USP") to the residential class. Under both current and proposed rates, these costs are recoverable from the residential class, whether sales or delivery service. Line 8 relates to the uncollectible component and Line 15 relates to the customer compliance and other service costs attributable to low income residential customers. This cost category includes the costs associated with customer service activity for residential customers, including the costs associated with the Company's Low Income Usage Reduction Program ("LIURP") and Emergency Service programs.

In addition on Page 8, Line 5, Residential Customer Payment Options were assigned directly to the residential rate class. These options are explained in section IV of Company witness Waruszewski's direct testimony under "Transaction Fees Proposal". These proposed options would be offered only to the residential customer class, and therefore, the expense is directly assigned to the residential class.

And finally, on Page 8, Line 29, Multifamily House Line Reimbursement expense was assigned directly to the residential customer class. This cost is explained in section II of Company witness Waruszewski's direct testimony under "Multifamily House Line Reimbursement". This proposed program would be offered only to the residential customer class, and therefore, the expense is directly assigned to the residential class.

Q. How did you handle Uncollectibles related to unbundling?

A. Columbia utilizes three systems to bill customers, 1) DIS (Distributed Information System) that bills customers who's meter is read monthly for either sales or Choice Transportation service, 2) GMB (Gas Measurement Billing) that bills customers who's meter is read daily for either sales or Choice distribution service, and GTS (Gas Transportation System) that bills customers for traditional (non-Choice) distribution service. Please note the GMB and GTS billing systems do not bill residential customers. Because DIS billed net charge-offs are accounted for in the Company's accounting reports by customer class, the residential net charge-offs were assigned to the residential class. The DIS billed commercial net charge-offs were allocated between the SGSS1/SCD1/SGDS1 and SGSS2/SCD2/ SGDS2 rate classes based on DIS billed revenue within each class. The portion of Account 904 related to the GMB and GTS billing systems was allocated to GMB and GTS billed customers by rate class based on their GMB/GTS revenue.

Q. Please describe how you allocated plant Account 380 - Services and the related O&M accounts.

A. First, I identified the services related to MLS/MLDS and directly assigned them. The remaining investment in Account 380 - Services and the related O&M accounts was based on an actual assignment of services installed on customers' premises. Individual customer services were identified by size from the Company's DIS billing system, and accumulated by customer class and rate schedule. Based on the historic test year per book data, the average unit price per size of pipe was determined and applied to the number of services under each rate schedule based on pipe size. The resulting values, by rate schedule, were converted to percentages and used to allocate service investment and related expenses.

Q. Please describe how you allocated plant Account 381 – Meters and Account 382 – Meter Installations in the studies.

A. I have assigned meters to the various rate classes based on an actual inventory of meters installed on customers' premises. Columbia recognizes four separate pressure groups for meters. Each meter type varies in cost as the size increases. Individual installed meters as identified on DIS were summarized by the four pressure groups. The capitalized property investment as identified on the Company's books and records for the four pressure groups was divided by the number of meters as reflected on the Company's books and records as of November 30, 2015 to develop a cost per meter for each group of meters. The costs per meter were multiplied by the identified installed meters in DIS to determine the investment for each rate class. The percentages were developed for Account 381 and used for assigning Account 381 Meters as well as the investment in Account 382 Meter Installations.

Q. Please describe how you allocated plant accounts 383 – House Regulators and 384 – House Regulator Installations.

A. Both of these accounts contain costs that are directly associated with the cost of house regulators. These regulators are installed where the distribution lines are transporting gas at intermediate, medium, or high pressure. Recognizing this fact and understanding, therefore, that customers being served by low pressure lines do not require house regulators, I developed an allocation factor that excludes customers served from low pressure lines from the total. The allocation factor uses total number of customers, grouped by rate class, as assigned in DIS. The resulting allocation percentages are then applied to the total capitalized property investment, as identified on the Company's books and records to determine the cost of house regulators for each applicable rate class.

Q. Please describe how you allocated plant Account 385 – Industrial Measurement & Regulation ("M&R") Equipment in the studies.

A. Using data retrieved from DIS, I obtained, for each active customer who has an M&R Station assigned to them, each station's rate schedule and station number. Then, I cross-referenced these station identification numbers to the Company's plant accounting records in order to identify the cost of each station. Then, I grouped these costs into the corresponding rate classes (excluding MLS/MLDS) and used the resulting totals as the basis for allocating all M & R plant.

Q. Do you provide a more complete description of how these factors were developed and the related calculations?

A. Yes. In Exhibit MPB-1 attached to this testimony, entitled "Development of Allocation Factors", I provided a description for all allocation factors used for the studies. In Exhibit MPB-2, I included all calculations of all allocation factors. And in Exhibit MPB-3, I provided the rationale for factor selection, by account, as it pertains to the various categories of rate base and expense.

Q. Did you prepare a study in support of the company's minimum or system charges?

A. I prepared two studies in support of the Company's minimum or system charges. They are contained in Exhibit No. 111, Schedule 1, pages 14 through 30.

Q. Please describe the two studies.

A. The study included in Exhibit 111, Schedule No. 1, pages 14 through 22 contains the company's traditional customer charge study based on the customer-demand ACOS study and includes the customer portion of mains costs. Columbia has used this method in support of its customer charges in its previous general rate case filings. The study presented on pages 23 and 30 of Schedule No. 1 is similar, but excludes the customer component of mains and other operations.

Q. Why did you present the study excluding the customer component of mains?

A. I am aware that there have been disagreements concerning the inclusion of any mains costs as a customer component. Therefore, I included the alternative calculation excluding the customer component of mains. The Company does not agree with this approach, and continues to support its traditional customer cost study.

Q. Why does the Company believe a customer component of mains should be included in a minimum system customer charge study?

A. The allocation of a portion of distribution mains costs on a customer basis is appropriate because of the way the distribution system is designed. Customer-related costs include, at a minimum, the cost incurred by the Company to extend its existing distribution system using a minimum size pipe (2" diameter) to attach a customer to the distribution system. Simply stated, the customer component of mains calculated in the ACOS represents a minimum fixed cost investment in mains to attach a customer to the distribution system, and therefore, has a direct relationship to the number of customers served by the Company. At a minimum, fixed costs that have a direct relationship to number of customers served by the Company should be recovered equally from all customers within a rate class, and that is what a customer charge is designed to do.

Q. Did you prepare a study supporting the intra-class adjustment of storage costs between the SGDS1 and the SGSS1/SCD1 classes and between the SGDS2 and the SGSS2/SCD2 classes?

A. Yes. At the request of Company witness Bell, I prepared a study, included as Exhibit MPB-4, supporting the intra-class adjustment of storage costs from the SGDS1 and SGDS2 classes to the SGSS1, SGSS2, SCD1 and SCD2 classes. This adjustment is made because SGDS1 and SGDS2 customers are not Priority customers for whom Columbia purchases gas in storage to serve.

Q. Please describe this study.

A. The study calculates the storage carrying costs, by rate class, by applying the proposed pre-tax rate of return (Line 6) to the allocated storage balances (Line 3), and utilizing Allocation Factor No. 25. The resulting storage carrying costs for the SGS1/SGDS1 class and the SGS2/SGDS2 class (Line 7) includes costs that would, without an adjustment, be assigned entirely to the SGDS1 class (Line 15) and SGDS2 class (Line 22). These costs are assigned to the SGSS1 and SCD1 classes and the SGSS2 and SCD2 classes ratably, using a factor derived from their projected throughput (Lines 13 & 14 under the heading "Ratio" for the SGSS1 and SCD1 classes and Lines 20 & 21 for the SGSS2 and SCD2 classes). No other intra-class adjustments are being supported or shown on this exhibit.

Q. Does this complete your direct testimony?

A. Yes, it does.

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Direct Assignment

"Direct Assignment" refers to a specific identification and isolation of plant and/or expenses based on Columbia's accounting records and incurred exclusively to serve a specific customer or group of customers. Instances of the use of direct assignments in the study can be identified by the omission of an allocation factor number (generally in column c) and the use of the term "direct" immediately after the account number. The operative principle is to utilize direct assignment of plant and expenses wherever practicable and to allocate when accounting records do not indicate class categorization.

Factor No. 1 - Design Day

The quantities contained in Factor No. 1 represent the total demand projected to occur at Columbia's design peak day. See Exhibit MPB-2, Alloc 1.

Factor No. 2- Throughput Excluding Transportation

Throughput quantities, excluding transportation, for the twelve months ending December 31, 2017 are the basis for Factor No. 2. See Exhibit MPB-2, Alloc 2, 3 and 25.

Factor No. 3- Throughput Excluding MDS

Factor No. 3 represents the throughput quantities excluding MDS quantities for the twelve months ending December 31, 2017. See Exhibit MPB-2, Alloc 2, 3, and 25.

Factor No. 4- Gas Purchase Expense

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Factor No. 4 is based on gas cost assigned to each rate schedule for the twelve months ending December 31, 2017 using the applicable Gas Cost Recovery ("GCR") rates. See Exhibit MPB-2, Alloc41.

.**Factor No. 5 - Composite of Factors No. 1 and Throughput**

The determination of the total cost of transmission pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Exhibit MPB-2 Alloc 5 Page 3. The allocation of transmission pipe was calculated by applying Allocator No. 1 (total company design day volumes, excluding MLS/MLDS) to the total cost, recognizing that transmission mains are designed to serve an entire geographic area, as shown on Exhibit MPB-2 Alloc 5 Page 9.

The determination of the total cost of the low pressure only pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Exhibit MPB-2 Alloc 5 Pages 4 & 5. The allocation of low pressure pipe was calculated by applying, on a 50-50 basis, historical throughput (low pressure only) by rate class and design day volumes (low pressure only) by rate class to the total cost, as shown on Exhibit MPB-2 Alloc 5 Page 10.

The determination of the total cost of the regulated non-low pressure pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Exhibit MPB-2 Alloc 5 Page 6. The

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allocation of regulated non-low pressure pipe was calculated by applying, on a 50-50 basis, historical throughput (regulated non-low pressure only) by rate class and design day volumes (regulated non-low pressure only) by rate class to the total cost, as shown on Exhibit MPB-2 Alloc 5 Page 11.

The determination of the total cost of the remaining regulated pressure pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Exhibit MPB-2 Alloc 5 Pages 7 & 8. The allocation of remaining regulated pressure pipe was calculated by applying, on a 50-50 basis, historical throughput (total company excluding MLS/MLDS) by rate class and Allocator No. 1 (total company design day volumes) to the total cost, as shown on Exhibit MPB-2 Alloc 5 Page 11.

For each of these four categories of allocated cost for each rate class, the aggregated amounts were converted to percentages, as shown on Exhibit MPB-2 Alloc 5 Page 11, Line 21, which formed Allocation Factor No. 5.

Factor No. 5 combines design day quantities included in Factor No. 1 and throughput quantities for the historic test year ended November 30, 2015 to produce a composite Factor No. 5. Factor No. 5 was used to allocate mains and mains related accounts for the Peak and Average Study. Please see Exhibit MPB-2 Alloc 5, Development of Allocation Factors for the detail development of Factor No. 5.

Factor No. 6 - Average Number of Customers

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Customers for each month of the twelve months ending December 31, 2017 were averaged and used to develop Factor No. 6. See Exhibit MPB-2 Alloc 6.

Factor No. 7 – Current DIS Revenue

Factor No. 7 reflects gross charge-offs recorded during the twelve months ending November 30, 2015 to small usage customers through the Company's Distributive Information System. See Exhibit MPB-2 Alloc 7.

Factor No. 8 – Current GMB/GTS

Factor No. 8 reflects revenue to be billed during the twelve months ending December 31, 2017 to larger sales usage and transportation customers through the Company's Gas Measurement Billing and General Transportation Systems. See Exhibit MPB-2 Alloc 8.

Factor No. 9 – Customer Deposits

Factor No. 9 represents customer security deposits collected from customers by class as of November 30, 2015. See Exhibit MPB-2 Alloc 9.

Factor No. 10 - Forfeited Discounts

Factor No. 10 is based on the amount of forfeited discounts billed to customers during the twelve months ended November 30, 2015. See Exhibit MPB-2 Alloc 10.

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Factor No. 11 - Distribution Plant Excluding Other

Factor No. 11 ratios are based on the spread of distribution plant dollars, excluding gas plant accounts 375.70, 375.71, and 387, to the customer groups resulting from the application of the various allocation factors to each gas plant account. The allocated dollars are aggregated and reduced to percentages to produce Factor No. 11. See Exhibit MPB-2 Alloc 11.

Factor No. 12 - Gross Plant

Factor No. 12 ratios are based on the spread of total plant dollars to the customer groups resulting from the application of the various allocation factors to each gas plant account. The allocated dollars are aggregated and reduced to percentages to produce Factor No. 12. See Exhibit MPB-2 Alloc 12.

Factor No. 13 – Mains – Account 376

Factor No. 13 reflects the relationship based on the spread of dollars in account 376 Mains among all customer classes that resulted from allocating the Mains using composite Factor No. 5 for the Demand-Commodity Study and Factor No. 20 for the Customer-Demand Study for classes that could not be directly assigned. The dollars are aggregated and reduced to percentages to produce Factor No. 13. See Exhibit MPB-2 Alloc 13.

Factor No. 14 – Composite Direct Plant – Accts 376 & 380

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Factor No. 14 reflects the relationship based on the spread of dollars in accounts 376 Mains and 380 Services among all customer classes resulting from the application of the appropriate account allocation factor. The allocated dollars in each account are aggregated and reduced to percentages to produce Factor No. 14. See Exhibit MPB-2 Alloc 14.

Factor No. 15 – Direct Assignment - Services

Factor No. 15 – reflects Services – Account 380 assigned by rate schedule based on an actual assignment of services installed on customers' premises. Individual customer services were identified by size kind from the Company's Distributive Information System ("DIS") and accumulated by customer class and rate schedule. Based on the historic test year per book data, average unit prices by service size were developed from the data and applied to the number of services under each rate schedule. The resulting values, by rate schedule were converted to percentages and used to allocate service investment and related expenses. See Exhibit MPB-2 Alloc 15.

Factor No. 16 – Direct Assignment – Meters

Meters were assigned to the various classes of customers based on meters installed on customers' premises. Columbia recognizes four separate pressure groups for meters. Each varies in cost as the size changes. Individually installed meters as identified

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on Columbia's Distributive Information System ("DIS") were summarized by the four pressure groups. The capitalized property investment, as identified on the Company's books and records for the four pressure groups, was divided by the number of installed meters as reflected on the company's books and records to develop a cost per meter for each group of meters. The costs per meter were multiplied by the identified installed meters on DIS to determine the investment for each customer class. The percentages were developed for account 381 and used for assigning account 381 Meters as well as the investment in account 382 Meter Installations since these costs are incurred in direct relation with meters. See Exhibit MPB-2 Alloc 16.

Factor No. 17 – Direct Assignment - Ind M&R

Individual measuring stations are identified on Columbia's Distributive Information System ("DIS") by customer by station number and Columbia's plant records by station number. The investments were aggregated by rate schedule and reduced to percentages to produce Factor No. 17. See Exhibit MPB-2 Alloc 17.

Factor No. 18 - Other Distribution Expense

Factor No. 18 is based on the spread of dollars to the various classes of customers within the following distribution expense accounts:

Page 7 - Distribution Expense Allocation

Line 19 Account 871 - Distribution Load Dispatch

Line 20 Account 874 - Mains & Services

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Line 21 Account 875 - M & R - General

Line 22 Account 876 - M & R - Industrial

Line 23 Account 878 - Meters & House Regulators

Line 24 Account 879 - Customer Installation

Line 29 Account 886 - Structures & Improvements

Line 30 Account 887 - Mains

Line 31 Account 889 - M & R - General

Line 32 Account 890 - M & R - Industrial

Line 33 Account 892 - Services

Line 34 Account 893 - Meters & House Regulators

See Exhibit MPB-2 Alloc 18.

Factor No. 19 – O&M Excl Gas Pur, Uncollectibles, & A&G

Factor No. 19 is based on total Operating and Maintenance Expenses (Page 8, Line 38) less Gas Purchased Cost (Page 7, Line 1), Uncollectibles (Page 8, Lines 6, 7, 8 & 9), USP Rider (Page 8, Line 15) and A&G Expenses (Page 8, Line 37). See Exhibit MPB-2 Alloc 19.

Factor No. 20 Minimum System Mains

Factor No. 20 is a composite using customers and design day quantities to allocate mains. The development of the factor is presented on Exhibit MPB-2 Alloc 20.

As with Factor No. 5, the total historical cost of the mains, the quantity of mains,

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

and the directly assigned mains were all obtained from the company's plant accounting system and GIS system. Likewise, this data was used to calculate the average cost per foot of each unique combination of kind and size of pipe. Again, the mains were further grouped into one of the following four allocation categories: 'transmission', 'low pressure', 'regulated non-low pressure' and 'remaining regulated pressure', as explained in Statement No. 11. The allocation of each of these categories is further explained in Statement No. 11.

The determination of the total cost of the transmission pipe was arrived at by multiplying the quantity of each kind and size of this pipe by each respective average cost per unit, as shown on Exhibit MPB-2 Alloc Page 3. The allocation of transmission pipe was calculated by applying Allocator No. 1 (total company design day volumes, excluding MLS/MLDS) to the total cost, recognizing that transmission mains are designed to serve an entire geographic area, as shown on Exhibit MPB-2 Alloc 20 Page 9.

For the remaining categories of pipe, a minimum 2" system approach is used. The concept is based on the assumption that in order for a customer to obtain service, mains of at least the most common, minimum size in the distribution system must be present. That portion of the Mains Account investment is considered customer-related and is computed by multiplying the total pipe quantity in the system by the cost per foot for the most prevalent size of mains, that being two inch. The cost of the minimum

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DEVELOPMENT OF ALLOCATION FACTORS

system, computed in that manner, is divided by the total cost of all mains to arrive at a Customer Component factor. The reciprocal of the Customer Component factor becomes the Demand Component factor and is used to allocate the remaining mains costs which are considered demand related and allocated using the appropriate design day factor.

The already determined total cost of for the low pressure only pipe was allocated by applying the customer component percentage of 46.603% (Exhibit MPB-2 Alloc 20 Page 10) to the average number of low pressure customers, and the demand component percentage 53.397% (Exhibit MPB-2 Alloc 20 Page 20) to design day volumes (low pressure only). Finally, these two results are added together to form the minimum system percentages as shown on Exhibit MPB-2 Alloc 2 Page 10.

As with the method for determining the low pressure minimum system percentage, the total cost of the regulated non-low pressure only pipe was allocated by applying the customer component percentage of 56.152% (Exhibit MPB-2 Alloc 20 Page 11) to the average number of regulated non-low pressure customers, and the demand component percentage 43.848% (Exhibit MPB-2 Alloc 20 Page 11) to design day volumes (regulated non-low pressure only). Finally, these two results are added together to form the minimum system percentages as shown on Exhibit MPB-2 Alloc 20 Page 11.

Again, following the same method for determining the low pressure and regulated

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

non-low pressure minimum system percentages, the total cost of the remaining regulated pressure pipe was allocated by applying the customer component percentage of 41.165% (Exhibit MPB-2 Alloc 20 Page 12) to the average number of company customers (excluding MLS/MLDS), and the demand component percentage 58.835% (Exhibit MPB-2 Alloc 20 Page 12) to total company design day volumes (excluding MLS/MLDS). Finally, these two results are added together to form the minimum system percentages as shown on Exhibit MPB-2 Alloc 20 Page 12.

Each of these four categories of allocated costs were aggregated, to arrive at a total cost for each rate class. These aggregated amounts were then converted to percentages, as shown on Exhibit MPB-2 Alloc 20 Page 12, which formed Allocation Factor No. 20.

Factor No. 21 – House Regulators

Factor No. 21 is based on the bill counts for all customers that are not served by low pressure lines. These counts are segregated by customer class and converted to percentages to create Factor No. 21 and used for assigning account 383 House Regulators as well as the investment in account 384 House Regulator Installations since these costs are incurred in direct relation with House Regulators. See Exhibit MPB-2 Alloc 21.

Factor No. 22 –Average Factor Nos. 5 & 20

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS

Factor No. 22 is based on the average of Factor Nos. 5 and 20 on an equal basis and is used to average the Customer-Demand Study and the Peak and Average Study. See Exhibit MPB-2 Alloc 22.

Factor No. 23 – Meters and House Regulators

Factor No. 23 reflects the relationship based on the spread of dollars in accounts 381 Meters, 381.10 Automatic Meter Reading, 382 Meter Installations, 383 House Regulators, and 384 House Regulator Installations (Page 3, Lines 34 through 38) among all customer classes resulting from the application of the appropriate account allocation factor. The allocated dollars in each account are aggregated and reduced to percentages to produce Factor No. 23. See Exhibit MPB-2 Alloc 23.

Factor No. 24 - Labor

Factor No. 24 is based on the allocation of labor charges with the various FERC Accounts. The labor dollars allocated to the various rate classes are summed and converted to percentages to create Factor No. 24. See Exhibit MPB-2 Alloc 24.

Factor No. 25 – Sales and CHOICE Transportation

Factor No. 25 is based on the sales and CHOICE transportation activity for the twelve months ending December 31, 2017. See Exhibit MPB-2 Alloc 25.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 1
DESIGN DAY [1] (2015-2016)

LINE NO.	Rate	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	Total
1	RCC	32,600	0	0	0	0	32,600
2	RGC	0	0	0	0	0	0
3	RGS	0	0	0	0	0	0
4	RS	311,900	0	0	0	0	311,900
5	RTC	97,400	0	0	0	0	97,400
6	LG1	0	0	0	5,900	0	5,900
7	LG2	0	0	0	6,700	0	6,700
8	LG3	0	0	0	0	1,700	1,700
9	NSI	0	0	0	0	0	0
10	SGS	0	63,400	0	0	0	63,400
11	SG2	0	0	58,400	0	0	58,400
12	SG3	0	100	0	0	0	100
13	SG4	0	0	1,100	0	0	1,100
14	TAG1	0	469	0	0	0	469
15	TAG2	0	0	13,319	0	0	13,319
16	TAG5	0	1,373	0	0	0	1,373
17	TAG6	0	0	26,526	0	0	26,526
18	TIB	0	0	0	32,976	0	32,976
19	TIF	0	0	0	0	19,944	19,944
20	TIF-EFACT	0	0	0	0	359	359
21	TIG	0	0	0	0	5,954	5,954
22	TIG-EFACT	0	0	0	0	0	0
23	TIH	0	0	0	0	0	0
24	TI4	0	0	0	16,149	0	16,149
25	TI8	0	0	0	0	15,221	15,221
26	TMA	0	0	0	0	0	0
27	TM2	0	0	0	0	0	0
28	TM3	0	0	0	0	0	0
29	801	0	0	0	614	0	614
30	802	0	0	0	0	0	0
31	803	0	0	0	0	1,905	1,905
32	806	0	0	0	244	0	244
33	808	0	0	0	0	1,676	1,676
34	809	0	0	0	0	2,065	2,065
35	810	0	0	0	0	1,734	1,734
36	815	0	0	0	0	0	0
37	816	0	0	0	0	670	670
38	819	0	0	0	0	3,473	3,473
39	820	0	0	0	0	2,557	2,557
40	821	0	0	0	0	0	0
41	830	0	0	0	0	0	0
42	831	0	0	0	0	0	0
43	833	0	0	0	0	959	959
44	838	0	0	0	280	0	280
45	839	0	0	0	0	0	0
46	840	0	0	0	0	1,118	1,118
47	841	0	0	39	0	0	39
48	845	0	0	0	0	2,253	2,253
49	846	0	0	0	0	3,056	3,056
50	847	0	0	0	166	0	166
51	848	0	0	52	0	0	52
52	850	0	0	0	0	0	0
53	851	0	0	0	0	0	0
54	852	0	0	401	0	0	401
55	853	0	0	135	0	0	135
56	854	0	0	272	0	0	272
57	855	0	0	26	0	0	26
58	856	0	0	0	176	0	176
59	857	0	0	29	0	0	29
60	858	0	0	0	158	0	158
61	859	0	0	0	0	838	838
62	860	0	0	45	0	0	45

[1] Includes Firm and Non-Firm Service. Volumes in MDth/Day.

EXHIBIT MPB-2
ALLOC 1

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 1
DESIGN DAY [1] (2015-2016)

LINE NO.	Rate		RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	Total
63	861		0	0	0	162	0	162
64	862		0	5	0	0	0	5
65	863		0	0	16	0	0	16
66	864		0	2	0	0	0	2
67	865		0	0	0	81	0	81
68	866		0	3	0	0	0	3
69	867		0	0	0	0	0	0
70	868		0	0	0	0	8	8
71	872		0	0	0	0	0	0
72	873		0	0	0	0	0	0
73	874		0	0	0	44	0	44
74	875		0	0	0	0	6,253	6,253
75	876		0	0	0	57	0	57
76	877		0	0	31	0	0	31
77	878		0	0	0	0	0	0
78	879		0	0	0	0	0	0
79	SCC		0	17,400	0	0	0	17,400
80	SC2		0	0	9,500	0	0	9,500
81	Total		441,900	82,752	109,891	63,707	71,743	769,993
82		ALLOCATOR #1	57.390%	10.747%	14.272%	8.274%	9.317%	100.000%

[1] Includes Firm and Non-Firm Service. Volumes in MDth/Day.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTORS 2, 3, & 25
THROUGHPUT EXCLUDING TRANSPORTATION, THROUGHPUT EXCLUDING MDS

LINE NO.		RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS	TOTAL
	Sales							
1	RSS	24,297,875	-	-	-	-	-	24,297,875
2	RDGSS	-	-	-	-	-	-	-
3	RCC 1/	2,551,794	-	-	-	-	-	2,551,794
4	SGSS1	-	4,337,145	-	-	-	-	4,337,145
5	SGSS2	-	-	4,765,071	-	-	-	4,765,071
6	NSS/MLSS-1	-	-	-	-	-	65,000	65,000
7	LGSS1 & 2	-	-	-	884,981	-	-	884,981
8	LGSS3 & greater	-	-	-	-	73,145	-	73,145
	Transportation							-
8	RDS	7,554,000	-	-	-	-	-	7,554,000
9	RDGDS	-	-	-	-	-	-	-
10	SCD1	-	1,376,587	-	-	-	-	1,376,587
11	SCD2	-	-	1,023,437	-	-	-	1,023,437
12	SGDS1	-	158,613	-	-	-	-	158,613
13	SGDS2	-	-	3,293,047	-	-	-	3,293,047
14	SDS	-	-	-	6,341,014	-	-	6,341,014
15	LDS	-	-	-	-	20,981,336	-	20,981,336
16	MLDS	-	-	-	-	-	5,181,000	5,181,000
17	Total Throughput Excl. Trans. (Allocator 2)	26,849,669	4,337,145	4,765,071	884,981	73,145	65,000	36,975,011
18	**ALLOCATOR #2**	72.616%	11.730%	12.887%	2.393%	0.198%	0.176%	
19	Total Throughput Excl. MDS (Allocator 3)	34,403,669	5,872,345	9,081,554	7,225,995	21,054,482		77,638,044
20	**ALLOCATOR # 3**	44.313%	7.564%	11.697%	9.307%	27.119%		
21	**Sales and Choice Volume**	34,403,669	5,713,732	5,788,507	884,981	73,145	65,000	46,929,035
22	**ALLOCATOR #25**	73.309%	12.175%	12.335%	1.886%	0.156%	0.139%	

NOTE: **1/ RCC rate schedule is for CAP customers. They can be either CHOICE or Sales. This year they are Sales on the books.**

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 4
GAS PURCHASE EXPENSE

LINE NO.		RSS/RDS GAS COST	SGSS1/SCD1/SGDS1 GAS COST	SGSS2/SCD2/SGDS2 GAS COST	SDS/LGSS GAS COST	LDS/LGSS GAS COST	MDS GAS COST	TOTAL
1	RSS	75,308,835	-	-			-	75,308,835
2	PRDGSS	-	-	-			-	-
3	RCC	9,328,082	-	-			-	9,328,082
4	RDS	5,558,233	-	-			-	5,558,233
5	PRDGDS	-	-	-			-	-
6	SGSS	-	13,442,546	14,768,860			-	28,211,406
7	NSS	-	-	-			272,136	272,136
8	SCD	-	1,012,893	753,045			-	1,765,938
9	SGDS	-	23,099	696,912			-	720,011
10	LGS	-	-	-	2,742,911	226,707	-	2,969,618
11	TOTAL	90,195,150	14,478,538	16,218,817	2,742,911	226,707	272,136	124,134,259
12	ALLOCATOR #4	72.658%	11.664%	13.066%	2.210%	0.183%	0.219%	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: M BALMERT

1 **Total Company - Average Unit Cost of Mains**

Line	Kind	Size	Key	Total Company Quantity (Footage)	Total Company Amount	Direct Assignment Quantity (Footage)	Direct Assignment Amount	Allocable Pipe Quantity (Footage)	Allocable Pipe Amount	Average Cost per Foot
2				Total Company		Direct Assignment		Allocable Pipe		Average
3	Kind	Size	Key	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Cost per Foot
4	CAST IRON	3"	CAST IRON 3"	8,799	9,295	-	-	8,799	9,295	1.06
5	CAST IRON	4"	CAST IRON 4"	102,696	266,265	-	-	102,696	266,265	2.59
6	CAST IRON	6"	CAST IRON 6"	33,446	80,873	-	-	33,446	80,873	2.42
7	CAST IRON	8"	CAST IRON 8"	13,471	66,288	-	-	13,471	66,288	4.92
8	CAST IRON	10"	CAST IRON 10"	2,202	8,506	-	-	2,202	8,506	3.86
9	CAST IRON	12"	CAST IRON 12"	867	58,051	-	-	867	58,051	66.96
10	PLASTIC	1"	PLASTIC 1"	30,285	133,100	-	-	30,285	133,100	4.39
11	PLASTIC	1-1/8"	PLASTIC 1-1/8"	1,402	5,709	-	-	1,402	5,709	4.07
12	PLASTIC	1-1/4"	PLASTIC 1-1/4"	387,698	2,179,025	-	-	387,698	2,179,025	5.62
13	PLASTIC	2"	PLASTIC 2"	9,831,105	135,539,936	-	-	9,831,105	135,539,936	13.79
14	PLASTIC	3"	PLASTIC 3"	2,268,335	27,626,828	-	-	2,268,335	27,626,828	12.18
15	PLASTIC	4"	PLASTIC 4"	5,962,527	245,379,171	808	58,818	5,961,719	245,320,353	41.15
16	PLASTIC	6"	PLASTIC 6"	2,290,954	150,581,221	645	20,688	2,290,309	150,560,533	65.74
17	PLASTIC	8"	PLASTIC 8"	1,125,665	108,324,662	-	-	1,125,665	108,324,662	96.23
18	STEEL	1/2"	STEEL 1/2"	3	233	-	-	3	233	77.74
19	STEEL	3/4"	STEEL 3/4"	7,104	13,286	-	-	7,104	13,286	1.87
20	STEEL	1"	STEEL 1"	41,334	104,463	-	-	41,334	104,463	2.53
21	STEEL	1-1/4"	STEEL 1-1/4"	282,941	767,174	-	-	282,941	767,174	2.71
22	STEEL	1-1/2"	STEEL 1-1/2"	11,436	12,618	-	-	11,436	12,618	1.10
23	STEEL	2"	STEEL 2"	3,461,005	9,150,861	840	4,331	3,460,165	9,146,531	2.64
24	STEEL	2-1/2"	STEEL 2-1/2"	4,740	3,178	-	-	4,740	3,178	0.67
25	STEEL	3"	STEEL 3"	1,017,996	2,988,692	-	-	1,017,996	2,988,692	2.94
26	STEEL	3-1/4"	STEEL 3-1/4"	653	3,764	-	-	653	3,764	5.76
27	STEEL	3-1/2"	STEEL 3-1/2"	8,138	27,318	-	-	8,138	27,318	3.36
28	STEEL	4"	STEEL 4"	5,386,015	23,941,148	4,809	26,695	5,381,206	23,914,453	4.44
29	STEEL	4-1/2"	STEEL 4-1/2"	1,458	24,094	-	-	1,458	24,094	16.53
30	STEEL	4-7/8"	STEEL 4-7/8"	13,967	18,898	-	-	13,967	18,898	1.35
31	STEEL	5"	STEEL 5"	46,546	51,374	93	41	46,453	51,333	1.11
32	STEEL	5-3/16"	STEEL 5-3/16"	19,365	37,805	-	-	19,365	37,805	1.95
33	STEEL	5-1/4"	STEEL 5-1/4"	621	344	-	-	621	344	0.55
34	STEEL	5-1/2"	STEEL 5-1/2"	295	343	-	-	295	343	1.16
35	STEEL	5-5/8"	STEEL 5-5/8"	21,067	22,053	-	-	21,067	22,053	1.05
36	STEEL	6"	STEEL 6"	3,320,548	31,564,756	17,105	126,426	3,303,443	31,438,331	9.52
37	STEEL	6-1/4"	STEEL 6-1/4"	18,188	5,811	-	-	18,188	5,811	0.32
38	STEEL	6-5/8"	STEEL 6-5/8"	110,652	694,540	-	-	110,652	694,540	6.28
39	STEEL	7-5/8"	STEEL 7-5/8"	2,336	12,224	-	-	2,336	12,224	5.23
40	STEEL	8"	STEEL 8"	1,631,542	45,481,057	-	-	1,631,542	45,481,057	27.88
41	STEEL	8-1/4"	STEEL 8-1/4"	282	2,429	-	-	282	2,429	8.61
42	STEEL	8-5/8"	STEEL 8-5/8"	8,232	361,804	-	-	8,232	361,804	43.95
43	STEEL	9-5/8"	STEEL 9-5/8"	1,269	7,380	-	-	1,269	7,380	5.82
44	STEEL	10"	STEEL 10"	758,897	21,889,932	-	-	758,897	21,889,932	28.84
45	STEEL	12"	STEEL 12"	422,485	30,137,252	-	-	422,485	30,137,252	71.33
46	STEEL	14"	STEEL 14"	450	5,167	-	-	450	5,167	11.48
47	STEEL	16"	STEEL 16"	330,022	17,576,276	-	-	330,022	17,576,276	53.26
48	STEEL	20"	STEEL 20"	34,196	6,960,022	-	-	34,196	6,960,022	203.52
49	WROUGHT IRON	2"	WROUGHT IRON 2"	31,359	25,521	-	-	31,359	25,521	0.81
50	WROUGHT IRON	3"	WROUGHT IRON 3"	54,892	7,999	-	-	54,892	7,999	0.15

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: M. BALMERT

1 Total Company - Average Unit Cost of Mains (Cont)

Line	Kind	Size	Key	Total Company Quantity (Footage)	Total Company Amount	Direct Assignment Quantity (Footage)	Direct Assignment Amount	Allocable Pipe Quantity (Footage)	Allocable Pipe Amount	Average Cost per Foot
2				Total Company		Direct Assignment		Allocable Pipe		Average
3	Kind	Size	Key	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Cost per Foot
4	WROUGHT IRON	4"	WROUGHT IRON 4"	71,351	4,358	-	-	71,351	4,358	0.06
5	WROUGHT IRON	6"	WROUGHT IRON 6"	74,382	254	-	-	74,382	254	0.00
6	WROUGHT IRON	6-5/8"	WROUGHT IRON 6-5/8"	1,622	151	-	-	1,622	151	0.09
7	WROUGHT IRON	8"	WROUGHT IRON 8"	156,604	2,311	-	-	156,604	2,311	0.01
8	WROUGHT IRON	10"	WROUGHT IRON 10"	69,435	683	-	-	69,435	683	0.01
9	WROUGHT IRON	12"	WROUGHT IRON 12"	9,122	5,721	-	-	9,122	5,721	0.63
10	Total Pipe			39,492,004	862,172,225	24,300	236,998	39,467,704	861,935,226	21.84
11	OTHER NON-PIPE				240,846,335		119,403		240,726,933	
12	Total Account 376				1,103,018,560		356,401		1,102,662,159	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: M. BALMERT

1	Total Company - Transmission Class Mains					
2					Average	
3	Kind	Size	Key	Quantity	Unit Cost	Amount
4	STEEL	10"	STEEL 10"	31,301	28.84	902,720.84
5	STEEL	12"	STEEL 12"	69,551	71.33	4,961,072.83
6	STEEL	16"	STEEL 16"	29,614	53.26	1,577,241.64
7	STEEL	2"	STEEL 2"	2,839	2.64	7,494.96
8	STEEL	4"	STEEL 4"	8,853	4.44	39,307.32
9	STEEL	6"	STEEL 6"	716	9.52	6,816.32
10	STEEL	8"	STEEL 8"	160,093	27.88	4,463,392.84
11	STEEL	1-1/2"	STEEL 1-1/2"	77	1.10	84.70
12	STEEL	3"	STEEL 3"	969	2.94	2,848.86
13	Total			304,013		11,960,980.31

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: M. BALMERT

1 **Total Company - Distribution Low Pressure Mains**

Line	Kind	Size	Key	Quantity	Average Unit Cost	Amount
2						
3						
4	CAST IRON	3"	CAST IRON 3"	6,878	1.06	7,290.68
5	CAST IRON	4"	CAST IRON 4"	49,838	2.59	129,080.42
6	CAST IRON	6"	CAST IRON 6"	17,172	2.42	41,556.24
7	CAST IRON	8"	CAST IRON 8"	5,467	4.92	26,897.64
8	CAST IRON	10"	CAST IRON 10"	479	3.86	1,848.94
9	CAST IRON	12"	CAST IRON 12"	330	66.96	22,096.80
10	PLASTIC	1"	PLASTIC 1"	7,412	4.39	32,538.68
11	PLASTIC	1-1/8"	PLASTIC 1-1/8"	1,120	4.07	4,558.40
12	PLASTIC	1-1/4"	PLASTIC 1-1/4"	65,966	5.62	370,728.92
13	PLASTIC	2"	PLASTIC 2"	1,173,558	13.79	16,183,364.82
14	PLASTIC	3"	PLASTIC 3"	770,489	12.18	9,384,556.02
15	PLASTIC	4"	PLASTIC 4"	1,858,556	41.15	76,479,579.40
16	PLASTIC	6"	PLASTIC 6"	704,944	65.74	46,343,018.56
17	PLASTIC	8"	PLASTIC 8"	234,696	96.23	22,584,796.08
18	STEEL	1/2"	STEEL 1/2"	0	77.74	0.00
19	STEEL	3/4"	STEEL 3/4"	0	1.87	0.00
20	STEEL	1"	STEEL 1"	4,342	2.53	10,985.26
21	STEEL	1-1/4"	STEEL 1-1/4"	13,929	2.71	37,747.59
22	STEEL	1-1/2"	STEEL 1-1/2"	5,104	1.10	5,614.40
23	STEEL	2"	STEEL 2"	831,443	2.64	2,195,009.52
24	STEEL	2-1/2"	STEEL 2-1/2"	2,852	0.67	1,910.84
25	STEEL	3"	STEEL 3"	518,632	2.94	1,524,778.08
26	STEEL	3-1/4"	STEEL 3-1/4"	0	5.76	0.00
27	STEEL	3-1/2"	STEEL 3-1/2"	6,682	3.36	22,451.52
28	STEEL	4"	STEEL 4"	2,650,370	4.44	11,767,642.80
29	STEEL	4-1/2"	STEEL 4-1/2"	710	16.53	11,736.30
30	STEEL	4-7/8"	STEEL 4-7/8"	11,071	1.35	14,945.85
31	STEEL	5"	STEEL 5"	23,389	1.11	25,961.79
32	STEEL	5-3/16"	STEEL 5-3/16"	10,869	1.95	21,194.55
33	STEEL	5-1/4"	STEEL 5-1/4"	56	0.55	30.80
34	STEEL	5-1/2"	STEEL 5-1/2"	295	1.16	342.20
35	STEEL	5-5/8"	STEEL 5-5/8"	18,917	1.05	19,862.85
36	STEEL	6"	STEEL 6"	1,480,276	9.52	14,092,227.52
37	STEEL	6-1/4"	STEEL 6-1/4"	11,121	0.32	3,558.72
38	STEEL	6-5/8"	STEEL 6-5/8"	85,816	6.28	538,924.48
39	STEEL	8"	STEEL 8"	260,393	27.88	7,259,756.84
40	STEEL	8-1/4"	STEEL 8-1/4"	0	8.61	0.00
41	STEEL	8-5/8"	STEEL 8-5/8"	0	43.95	0.00
42	STEEL	9-5/8"	STEEL 9-5/8"	0	5.82	0.00
43	STEEL	10"	STEEL 10"	158,325	28.84	4,566,093.00
44	STEEL	12"	STEEL 12"	32,801	71.33	2,339,695.33
45	STEEL	14"	STEEL 14"	450	11.48	5,166.00
46	STEEL	16"	STEEL 16"	18,953	53.26	1,009,436.78
47	STEEL	20"	STEEL 20"	1,532	203.52	311,792.64

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

1 Total Company - Distribution Low Pressure Mains (Cont)

					Average	
2						
3	Kind	Size	Key	Quantity	Unit Cost	Amount
4	WROUGHT IRON	2"	WROUGHT IRON 2"	720	0.81	583.20
5	WROUGHT IRON	3"	WROUGHT IRON 3"	2,866	0.15	429.90
6	WROUGHT IRON	4"	WROUGHT IRON 4"	7,836	0.06	470.16
7	WROUGHT IRON	6"	WROUGHT IRON 6"	1,956	0.00	0.00
8	WROUGHT IRON	6-5/8"	WROUGHT IRON 6-5/8"	0	0.09	0.00
9	WROUGHT IRON	8"	WROUGHT IRON 8"	1,457	0.01	14.57
10	WROUGHT IRON	10"	WROUGHT IRON 10"	553	0.01	5.53
11	WROUGHT IRON	12"	WROUGHT IRON 12"	0	0.63	0.00
12	Total			11,060,621		217,400,280.62

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: M. BALMERT

1 **Total Company - Distribution Regulated Pressure Only Mains**

Line	Kind	Size	Key	Total Quantity	Direct Assignment Quantity	Allocable Quantity	Average Unit Cost	Amount
4	CAST IRON	4"	CAST IRON 4"	0	0	0	2.59	0.00
5	PLASTIC	1-1/4"	PLASTIC 1-1/4"	321,732	0	321,732	5.62	1,808,133.84
6	PLASTIC	2"	PLASTIC 2"	8,351,676	0	8,351,676	13.79	115,169,612.04
7	PLASTIC	3"	PLASTIC 3"	1,386,303	0	1,386,303	12.18	16,885,170.54
8	PLASTIC	4"	PLASTIC 4"	3,655,363	808	3,654,555	41.15	150,384,938.25
9	PLASTIC	6"	PLASTIC 6"	1,116,332	0	1,116,332	65.74	73,387,665.68
10	PLASTIC	8"	PLASTIC 8"	346,856	0	346,856	96.23	33,377,952.88
11	STEEL	1-1/4"	STEEL 1-1/4"	269,012	0	269,012	2.71	729,022.52
12	STEEL	2"	STEEL 2"	2,648,561	0	2,648,561	2.64	6,992,201.04
13	STEEL	3"	STEEL 3"	424,750	0	424,750	2.94	1,248,765.00
14	STEEL	4"	STEEL 4"	2,062,511	0	2,062,511	4.44	9,157,548.84
15	STEEL	5"	STEEL 5"	23,157	93	23,064	1.11	25,601.04
16	STEEL	6"	STEEL 6"	875,673	0	875,673	9.52	8,336,406.96
17	STEEL	8"	STEEL 8"	428,639	0	428,639	27.88	11,950,455.32
18	STEEL	10"	STEEL 10"	43,296	0	43,296	28.84	1,248,656.64
19	STEEL	12"	STEEL 12"	65,152	0	65,152	71.33	4,647,292.16
20	STEEL	16"	STEEL 16"	32,346	0	32,346	53.26	1,722,747.96
21	STEEL	20"	STEEL 20"	88	0	88	203.52	17,909.76
22	WROUGHT IRON	2"	WROUGHT IRON 2"	4,106	0	4,106	0.81	3,325.86
23	WROUGHT IRON	6"	WROUGHT IRON 6"	17,043	0	17,043	0.00	0.00
24	WROUGHT IRON	8"	WROUGHT IRON 8"	39,570	0	39,570	0.01	395.70
25	Total			22,112,166	901	22,111,265		437,093,802.03

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: M. BALMERT

Line	Kind	Size	Key	Quantity	Direct Assignment Quantity	Allocable Quantity	Amount
1	**Total Company - Remaining Regulated Pressure Mains**						
2					Direct Assignment	Allocable	
3	Kind	Size	Key	Quantity	Quantity	Quantity	Amount
4	CAST IRON	3"	CAST IRON 3"	1,921	0	1,921	2,004.55
5	CAST IRON	4"	CAST IRON 4"	52,858	0	52,858	137,184.34
6	CAST IRON	6"	CAST IRON 6"	16,274	0	16,274	39,317.13
7	CAST IRON	8"	CAST IRON 8"	8,004	0	8,004	39,390.26
8	CAST IRON	10"	CAST IRON 10"	1,723	0	1,723	6,657.02
9	CAST IRON	12"	CAST IRON 12"	537	0	537	35,954.08
10	PLASTIC	1"	PLASTIC 1"	22,873	0	22,873	100,561.06
11	PLASTIC	1-1/8"	PLASTIC 1-1/8"	282	0	282	1,150.85
12	PLASTIC	1-1/4"	PLASTIC 1-1/4"	0	0	0	162.41
13	PLASTIC	2"	PLASTIC 2"	305,871	0	305,871	4,186,958.93
14	PLASTIC	3"	PLASTIC 3"	111,543	0	111,543	1,357,101.25
15	PLASTIC	4"	PLASTIC 4"	448,608	0	448,608	18,455,835.55
16	PLASTIC	6"	PLASTIC 6"	469,678	645	469,033	30,829,848.89
17	PLASTIC	8"	PLASTIC 8"	544,113	0	544,113	52,361,912.74
18	STEEL	1/2"	STEEL 1/2"	3	0	3	233.23
19	STEEL	3/4"	STEEL 3/4"	7,104	0	7,104	13,286.39
20	STEEL	1"	STEEL 1"	36,992	0	36,992	93,477.85
21	STEEL	1-1/4"	STEEL 1-1/4"	0	0	0	404.09
22	STEEL	1-1/2"	STEEL 1-1/2"	6,255	0	6,255	6,918.51
23	STEEL	2"	STEEL 2"	(21,838)	840	(22,678)	(48,174.95)
24	STEEL	2-1/2"	STEEL 2-1/2"	1,888	0	1,888	1,266.97
25	STEEL	3"	STEEL 3"	73,645	0	73,645	212,299.98
26	STEEL	3-1/4"	STEEL 3-1/4"	653	0	653	3,764.26
27	STEEL	3-1/2"	STEEL 3-1/2"	1,456	0	1,456	4,866.84
28	STEEL	4"	STEEL 4"	664,281	4,809	659,472	2,949,953.96
29	STEEL	4-1/2"	STEEL 4-1/2"	748	0	748	12,357.74
30	STEEL	4-7/8"	STEEL 4-7/8"	2,896	0	2,896	3,952.38
31	STEEL	5"	STEEL 5"	0	0	0	(229.51)
31	STEEL	5-3/16"	STEEL 5-3/16"	8,496	0	8,496	16,610.86
32	STEEL	5-1/4"	STEEL 5-1/4"	565	0	565	313.27
33	STEEL	5-1/2"	STEEL 5-1/2"	0	0	0	1.22
34	STEEL	5-5/8"	STEEL 5-5/8"	2,150	0	2,150	2,189.85
35	STEEL	6"	STEEL 6"	963,883	17,105	946,778	9,002,879.74
36	STEEL	6-1/4"	STEEL 6-1/4"	7,067	0	7,067	2,251.81
37	STEEL	6-5/8"	STEEL 6-5/8"	24,836	0	24,836	155,615.09
38	STEEL	7-5/8"	STEEL 7-5/8"	2,336	0	2,336	12,224.00
39	STEEL	8"	STEEL 8"	782,417	0	782,417	21,807,452.44
40	STEEL	8-1/4"	STEEL 8-1/4"	282	0	282	2,429.17
41	STEEL	8-5/8"	STEEL 8-5/8"	8,232	0	8,232	361,803.89
42	STEEL	9-5/8"	STEEL 9-5/8"	1,269	0	1,269	7,379.67
43	STEEL	10"	STEEL 10"	525,975	0	525,975	15,172,461.11
44	STEEL	12"	STEEL 12"	254,981	0	254,981	18,189,191.90
45	STEEL	14"	STEEL 14"	0	0	0	0.88
46	STEEL	16"	STEEL 16"	249,109	0	249,109	13,266,849.23

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

1	**Total Company - Remaining Regulated Pressure Mains (Cont)**						
2					Direct Assignment	Allocable	
3	Kind	Size	Key	Quantity	Quantity	Quantity	Amount
4	STEEL	20"	STEEL 20"	32,578	0	32,578	6,830,319.24
5	WROUGHT IRON	2"	WROUGHT IRON 2"	26,533	0	26,533	21,611.74
6	WROUGHT IRON	3"	WROUGHT IRON 3"	52,026	0	52,026	7,569.17
7	WROUGHT IRON	4"	WROUGHT IRON 4"	63,515	0	63,515	3,688.11
8	WROUGHT IRON	6"	WROUGHT IRON 6"	55,383	0	55,383	254.09
9	WROUGHT IRON	6-5/8"	WROUGHT IRON 6-5/8"	1,622	0	1,622	150.66
10	WROUGHT IRON	8"	WROUGHT IRON 8"	115,577	0	115,577	1,900.53
11	WROUGHT IRON	10"	WROUGHT IRON 10"	68,882	0	68,882	677.66
12	WROUGHT IRON	12"	WROUGHT IRON 12"	9,122	0	9,122	5,721.31
13	Total			6,015,204	23,399	5,991,805	195,480,163.44

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: M. BALMERT

Line No.	Description	Alloc	Total Company	RS/RDS	SGS1/SCD1/SGDS1	SGS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MDS
	Total Mains Plant In Service		1,103,018,560.14						
	Direct Assigned Plant		236,996.27						
	Other - Non Pipe		240,846,335.47						
	Allocable Pipe		861,935,226.40						
1	**Transmission Pipe**		11,960,980.31						
2	**Low Pressure Pipe**		217,400,280.62						
3	**Regulated Pressure Pipe Only**		437,093,802.03						
4	**Remaining Regulated Pressure Pipe**		195,480,163.44						
5	**Allocated Pipe**		861,935,226.40						
6	**Allocation of Transmission Pipe**								
7	Allocable Transmission Pipe		$11,960,980.31						
8	Design Day Volumes (Total Company Excluding MDS)		769,993	441,900	82,752	109,891	63,707	71,743	
9	Percent Design Day Volumes		100.000%	57.390%	10.747%	14.272%	8.274%	9.317%	
10	**Allocation of Transmission Pipe**		$11,960,980.31	$6,864,406.60	$1,285,446.55	$1,707,071.11	989,651.51	1,114,404.54	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: M. BALMERT

Line No.	Description	Alloc	Total Company	RS/RDS	SGS1/SCD1/SGDS1	SGS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MDS
1	**Allocation of Low Pressure Pipe**								
2	Allocable Low Pressure Pipe		$217,400,280.62						
3	Throughput Volumes (excl MDS)		21,937,813.4	17,267,188.6	2,408,577.8	1,956,813.6	210,938.4	94,295.0	
4	Percent Throughput		100.000%	78.709%	10.979%	8.920%	0.962%	0.430%	
5	Throughput Component		50.000%	39.355%	5.490%	4.460%	0.481%	0.215%	
6	Design Day Volumes (excl MDS)		267,164	208,600	33,480	23,721	1,360	3	
7	Percent Design Day Volumes		100.000%	78.079%	12.532%	8.879%	0.509%	0.001%	
8	Demand Component		50.000%	39.040%	6.266%	4.440%	0.255%	0.001%	
9	Demand/Commodity Factor		100.000%	78.392%	11.756%	8.900%	0.736%	0.216%	
10	**Allocation of Low Pressure Pipe**		$217,400,280.62	$170,424,427.97	$25,557,576.99	$19,348,624.98	1,600,066.07	469,584.61	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 5
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
PEAK & AVERAGE

WITNESS: M. BALMERT

Line No.	Description	Alloc	Total Company	RS/RDS	SGS1/SCD1/SGDS1	SGS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MDS
1	**Allocation of Regulated Pressure Only Pipe**								
2	Allocable Regulated Pressure Only Pipe		$437,093,802.03						
3	Throughput Volumes (excl MDS)		29,603,566.1	13,746,233.4	2,208,432.3	4,072,940.8	2,389,193.4	7,186,766.2	
4	Percent Throughput		100.000%	46.434%	7.460%	13.758%	8.071%	24.277%	
5	Throughput Component		50.000%	23.216%	3.730%	6.879%	4.036%	12.139%	
6	Design Day Volumes (excl MDS)		324,811	163,100	31,551	53,275	39,196	37,689	
7	Percent Design Day Volumes		100.000%	50.214%	9.714%	16.402%	12.067%	11.603%	
8	Demand Component		50.000%	25.106%	4.857%	8.201%	6.034%	5.802%	
9	Demand/Commodity Factor		100.000%	48.322%	8.587%	15.080%	10.070%	17.941%	
10	**Allocation of Regulated Pressure Only Pipe**		$437,093,802.03	$211,212,467.02	$37,533,244.78	$65,913,745.35	44,015,345.86	78,418,989.02	
11	**Allocation of Remaining Regulated Pressure Pipe**								
12	Allocable Remaining Regulated Pressure Pipe		$195,480,163.44						
13	Throughput Volumes (Total Company excl MDS)		78,042,342	36,861,828	5,880,946	9,520,547	7,503,128	18,275,892	
14	Percent Throughput		100.000%	47.233%	7.536%	12 199%	9.614%	23.418%	
15	Throughput Component		50.000%	23.616%	3.768%	6.100%	4.807%	11.709%	
16	Design Day Volumes (Total Company excl MDS)		769,993	441,900	82,752	109,891	63,707	71,743	
17	Percent Design Day Volumes		100.000%	57.390%	10.747%	14.272%	8.274%	9.317%	
18	Demand Component		50.000%	28.694%	5.374%	7.136%	4.137%	4.659%	
19	Demand/Commodity Factor		100.000%	52.310%	9.142%	13.236%	8.944%	16.368%	
20	**Alloc. of Remaining Regulated Pressure Pipe**		$195,480,163.44	$102,255,673.50	$17,870,796.54	$25,873,754.43	17,483,745.82	31,986,193.15	
21	**Total Demand/Commodity Allocation Factor**		$861,935,226.40	$490,756,975.09	$82,247,064.86	$112,843,195.87	64,088,809.26	111,999,181.32	
			100.000%	56.937%	9.542%	13.092%	7.435%	12.994%	

EXHIBIT MPB-2
ALLOC 6

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 6
AVERAGE NO. OF CUSTOMERS

LINE NO.	TARIFF RATE SCHEDULES	TOTAL	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS	[1] Total No of Bills (Incl Final)	Final Bills
1	RSS	3,405,453	3,405,453	0	0	0	0	0	3,463,638	58,185
2	RDGSS	0	0	0	0	0	0	0	0	0
3	RCC	257,661	257,661	0	0	0	0	0	262,122	4,461
4	RDS	1,001,899	1,001,899	0	0	0	0	0	1,009,081	7,182
5	RDGDS	0	0	0	0	0	0	0	0	0
6	SGSS1	273,268	0	273,268	0	0	0	0	274,880	1,612
7	SGSS2	42,665	0	0	42,665	0	0	0	42,773	108
8	NSS	12	0	0	0	0	0	12	12	0
9	SCD1	90,107	0	90,107	0	0	0	0	90,425	318
10	SCD2	10,144	0	0	10,144	0	0	0	10,157	13
11	SGDS1	8,148	0	8,148	0	0	0	0	8,171	23
12	SGDS2	19,608	0	0	19,608	0	0	0	19,658	50
13	LGSS1 & 2	1,016	0	0	0	1,016	0	0	1,022	6
14	LGSS3 & greater	24	0	0	0	0	24	0	24	0
14	SDS	5,424	0	0	0	5,424	0	0	5,446	22
15	LDS	1,116	0	0	0	0	1,116	0	1,118	2
16	MLDS	108	0	0	0	0	0	108	108	0
17	Total Number of Bills	5,116,653	4,665,013	371,523	72,417	6,440	1,140	120	5,188,635	71,982
18	Average Number of Customers	426,388	388,751	30,960	6,035	537	95	10		
19	**ALLOCATOR #6**	100.000%	91.174%	7.261%	1.415%	0.126%	0.022%	0.002%		

[1] Used only in the Customer Charge calculation.

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 7
CURRENT DIS REVENUE

LINE NO.	ACCOUNT	TOTAL	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
		Total	Residential	Commercial				
1	DIS Billed Net Charge-offs - Sales Only	9,788,214.00	9,185,767.00	602,447.00				
2	DIS Billed Revenue - Comm/Ind Sales Only	65,898,506		35,155,881	30,742,625	0	0	0
3	Percent	100.000%		53.349%	46.651%	0.000%	0.000%	0.000%
4	Allocated DIS Billed Sales Net Charge-offs	9,788,214.00	9,185,767.00	321,399.45	281,047.55	0.00	0.00	0.00
		Total	Residential	Commercial				
5	DIS Billed Net Charge-offs - Choice Only	1,911,425.00	1,753,065.00	158,360.00				
6	DIS Billed Revenue - Comm/Ind Choice Only	25,311,717		8,613,396	16,698,321	0	0	0
7	Percent	100.000%		34.029%	65.971%	0.000%	0.000%	0.000%
8	Allocated DIS Billed Choice Net Charge-offs	1,911,425.00	1,753,065.00	53,888.32	104,471.68	0.00	0.00	0.00
9	Total DIS Billed Net Charge-offs	11,699,639.00	10,938,832.00	375,287.77	385,519.23	0.00	0.00	0.00
10	**ALLOCATOR #7**	100.000%	93.497%	3.208%	3.295%	0.000%	0.000%	0.000%

EXHIBIT MPB-2
ALLOC 8

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 8
CURRENT GMB/GTS REVENUE

LINE NO.	ACCOUNT	TOTAL	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	CURRENT GMB/GTS REVENUE	38,556,457	-	64,979	1,836,049	17,578,831	17,428,134	1,648,464
2	**ALLOCATOR #8**	100.000%	0.000%	0.169%	4.762%	45.592%	45.202%	4.275%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 9
DIRECT ASSIGNMENT - CUSTOMER DEPOSITS

LINE NO.		RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	TOTAL
1	Residential Unlisted	44,355	-	-	44,355
2	RS	1,655,404	-	-	1,655,404
3	RTC	203,264	-	-	203,264
4	Commercial Unlisted	-	14,838	-	14,838
5	LG2	-	20,254	-	20,254
6	SCC	-	38,876	-	38,876
7	SC2	-	-	5,352	5,352
8	SGS	-	555,499	-	555,499
9	SGT	-	34,600	-	34,600
10	SG2	-	-	57,213	57,213
11	SG3	-	2,978	-	2,978
12	TOTAL	1,903,023	667,045	62,565	2,632,633
13	**ALLOCATOR #9**	72.285%	25.338%	2.377%	100.000%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 10
FORFEITED DISCOUNTS

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	487.00	FORFEITED DISCOUNTS - DIS	1,098,551	871,157	106,404	115,330	5,357	303	-
2	487.00	FORFEITED DISCOUNTS - GMB & GTS	93,727	-	158	4,463	42,733	42,366	4,007
3		TOTAL CURRENT SALES AND TRANSPORTATION REVENUE	1,192,278	871,157	106,562	119,793	48,090	42,669	4,007
4		**ALLOCATOR #10**	100.000%	73.067%	8.938%	10.047%	4.033%	3.579%	0.336%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 11
DISTRIBUTION PLANT EXCLUDING ACCOUNTS 375.70, 375.71, & 387

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	374.10	LAND - CITY GATE & M/L IND M&R	21,944	16,543	1,971	1,679	882	869	-
2	374.20	LAND - OTHER DISTRIBUTION	477,118	359,700	42,845	36,500	19,175	18,899	-
3	374.30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	71,893	8,563	7,295	3,833	3,777	-
4	374.40	LAND RIGHTS - OTHER DISTRIBUTION	2,737,177	2,063,558	245,799	209,394	110,007	108,420	-
5	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	-	-	-	-	-	-	-
6	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	13	11	1	-	-	1	-
7	374.50	RIGHTS OF WAY	3,238,374	2,441,411	290,806	247,736	130,150	128,272	-
8	374.50	DIRECT - RIGHTS OF WAY	1,246	-	-	-	-	-	1,246
9	375.20	M & R STRUCTURES - CITY GATE	743,068	560,199	66,728	56,846	29,864	29,433	-
10	375.31	M & R STRUCTURES - LOCAL GAS PURCH	946,925	713,887	85,034	72,440	38,057	37,508	-
11	375.40	M & R STRUCTURES - REGULATING	3,813,061	2,874,667	342,413	291,699	153,247	151,035	-
12	375.40	DIRECT - M & R STRUCTURES - REGULATING	27,124	-	-	-	-	-	27,124
12	375.60	M & R STRUCTURES - DIST. IND. M & R	87,670	-	3,514	16,151	36,218	31,787	-
13	375.80	M & R STRUCTURES - COMMUNICATION	16,515	12,451	1,483	1,263	664	654	-
14	376.00	MAINS	1,354,749,182	1,021,345,408	121,656,477	103,638,312	54,447,370	53,661,615	-
15	376.00	DIRECT - MAINS - MDS	226,885	-	-	-	-	-	226,885
16	376.08	MAINS-CSL REPLACEMENTS	23,785,876	17,932,172	2,135,972	1,819,620	955,954	942,159	-
17	376.30	MAINS-BARE STEEL	68,743,268	51,825,550	6,173,146	5,258,860	2,762,792	2,722,921	-
18	376.30	DIRECT - MAINS-BARE STEEL	129,516	-	-	-	-	-	129,516
19	376.80	MAINS-CAST IRON	523,053	394,330	46,970	40,014	21,022	20,718	-
20	378.10	M & R EQUIP - GENERAL	55,331	41,714	4,969	4,233	2,224	2,192	-
21	378.20	M & R EQUIP - GENERAL - REGULATING	46,736,190	35,234,413	4,196,910	3,575,319	1,878,328	1,851,221	-
22	378.20	DIRECT - M & R EQUIP-GEN-REG	291,035	-	-	-	-	-	291,035
23	378.30	M & R EQUIP - LOCAL GAS PURCHASES	461,790	348,144	41,469	35,327	18,559	18,292	-
24	379.10	M & R EQUIP - CITY GATE	141,567	106,727	12,713	10,830	5,690	5,608	-
25	379.11	M & R EQUIP - EXCHANGE GAS	(450)	(339)	(40)	(34)	(18)	(18)	-
26	380.00	SERVICES	490,342,928	445,265,703	36,118,660	7,595,412	1,015,010	348,144	-
27	380.00	DIRECT - SERVICES	39,403	-	-	-	-	-	39,403
28	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-
29	381.00	METERS	37,714,590	28,095,484	1,518,767	7,606,656	380,540	107,109	6,034
30	381.10	AUTOMATIC METER READING	24,289,208	18,094,246	978,126	4,898,890	245,078	68,981	3,886
31	382.00	METER INSTALLATIONS	37,776,149	28,141,342	1,521,246	7,619,071	381,161	107,284	6,044
32	383.00	HOUSE REGULATORS	12,047,377	10,914,201	878,013	224,322	26,143	4,699	-
33	384.00	HOUSE REG INSTALLATIONS	3,864,772	3,501,252	281,665	71,962	8,387	1,507	-
34	385.00	IND M&R EQUIPMENT	5,047,477	-	202,303	929,846	2,085,214	1,830,114	-
35	385.00	DIRECT - IND M&R EQUIPMENT	373,291	-	-	-	-	-	373,291
36	385.10	IND M&R EQUIPMENT - LG VOLUME	1,151,820	-	46,165	212,188	475,840	417,627	-
37		TOTAL	2,120,695,852	1,670,354,663	176,902,683	144,481,828	65,231,389	62,620,826	1,104,464
38		ALLOCATOR #11	100.000%	78.764%	8.342%	6.813%	3.076%	2.953%	0.052%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	301.00	Organizational Costs	100,099						
2	302.21	Franchises/Consent, Perpetual	26,489						
3	303.00	Misc Intangible Plant	4,809,062						
4	303.30	Misc Software	31,528,188						
5	305.00	Structures & Improvements	0						
6	301-303	TOTAL INTANGIBLE PLANT	36,463,839	28,720,378	3,041,813	2,484,281	1,121,628	1,076,777	18,961
7	350.10	Land	23,882						
8	350.20	Rights of Way	1,932						
9	351.20	Compressor Station Structures	3,190,982						
10	352.01	Wells Construction	799,134						
11	352.02	Wells Equipment	168,680						
12	352.10	Storage Leasehold and Rights	139,442						
13	352.12	Other Leases	67,498						
14	353.00	Lines	405,288						
15	354.00	Compressor Station Equipment	962,222						
16	355.00	Measuring & Regulating Equipment	123,010						
17	362.00	Gas Holders	0						
18	362.10	Environmental Remediation	0						
18	350-362	TOTAL UNDERGROUND STORAGE	5,882,069	4,312,086	716,142	725,553	110,936	9,176	8,176
19	374.10	LAND - CITY GATE & M/L IND M&R	21,944	16,543	1,971	1,679	882	869	0
20	374.20	LAND - OTHER DISTRIBUTION	477,118	359,700	42,845	36,500	19,175	18,899	0
21	374:30	LAND RIGHTS - CITY GATE MAIN LINE	95,361	71,893	8,563	7,295	3,833	3,777	0
22	374.40	LAND RIGHTS - OTHER DISTRIBUTION	2,737,177	2,063,558	245,799	209,394	110,007	108,420	0
23	374.40	DIRECT - LAND RIGHTS-OTHER DISTRIBUTION	0	0	0	0	0	0	0
24	374.41	LAND RIGHTS - OTHER DISTRIBUTION LOC	13	11	1	0	0	1	0
25	374.50	RIGHTS OF WAY	3,238,374	2,441,411	290,806	247,736	130,150	128,272	0
26	374.50	DIRECT - RIGHTS OF WAY	1,246	0	0	0	0	0	1,246
27	375.20	M & R STRUCTURES - CITY GATE	743,068	560,199	66,728	56,845	29,864	29,433	0
28	375.31	M & R STRUCTURES - LOCAL GAS PURCH	946,925	713,887	85,034	72,440	38,057	37,508	0
29	375.40	M & R STRUCTURES - REGULATING	3,813,061	2,874,667	342,413	291,699	153,247	151,035	0
30	375.40	DIRECT - M & R STRUCTURES - REGULATING	27,124	0	0	0	0	0	27,124
31	375.60	M & R STRUCTURES - DIST. IND. M & R	87,670	0	3,514	16,151	36,218	31,787	0
32	375.70	M & R STRUCTURES - OTHER	7,821,943	6,160,875	652,506	532,909	240,603	230,982	4,067
33	375.71	M & R STRUCTURES - OTHER LEASED	4,517,569	3,558,218	376,856	307,782	138,960	133,404	2,349
34	375.80	M & R STRUCTURES - COMMUNICATION	16,515	12,451	1,483	1,263	664	654	0
35	376.00	MAINS	1,354,749,181	1,021,345,408	121,656,477	103,638,312	54,447,370	53,661,615	0
36	376.00	DIRECT - MAINS - MDS	226,885	0	0	0	0	0	226,885
37	376.08	MAINS-CSL REPLACEMENTS	23,785,876	17,932,172	2,135,972	1,819,620	955,954	942,159	0

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
		DISTRIBUTION PLANT							
1	376.30	MAINS-BARE STEEL	68,743,268	51,825,550	6,173,146	5,258,860	2,762,792	2,722,921	0
2	376.30	DIRECT - MAINS-BARE STEEL	129,516	0	0	0	0	0	129,516
3	376.80	MAINS-CAST IRON	523,053	394,330	46,970	40,014	21,022	20,718	0
4	378.10	M & R EQUIP - GENERAL	55,331	41,714	4,969	4,233	2,224	2,192	0
5	378.20	M & R EQUIP - GENERAL - REGULATING	46,736,190	35,234,413	4,196,910	3,575,319	1,878,328	1,851,221	0
6	378.20	DIRECT - M & R EQUIP-GEN-REG	291,035	0	0	0	0	0	291,035
7	378.30	M & R EQUIP - LOCAL GAS PURCHASES	461,790	348,144	41,469	35,327	18,559	18,292	0
8	379.10	M & R EQUIP - CITY GATE	141,567	106,727	12,713	10,830	5,690	5,608	0
9	379.11	M & R EQUIP - EXCHANGE GAS	(450)	(339)	(40)	(34)	(18)	(18)	0
10	380.00	SERVICES	490,342,928	445,265,703	36,118,660	7,595,412	1,015,010	348,144	0
11	380.00	DIRECT - SERVICES	39,403	0	0	0	0	0	39,403
12	380.12	CSL REPLACEMENT	0	0	0	0	0	0	0
13	381.00	METERS	37,714,590	28,095,484	1,518,767	7,606,656	380,540	107,109	6,034
14	381.10	AUTOMATIC METER READING	24,289,208	18,094,246	978,126	4,898,890	245,078	68,981	3,886
15	382.00	METER INSTALLATIONS	37,776,149	28,141,342	1,521,246	7,619,071	381,161	107,284	6,044
16	383.00	HOUSE REGULATORS	12,047,377	10,914,201	878,013	224,322	26,143	4,699	0
17	384.00	HOUSE REG INSTALLATIONS	3,864,772	3,501,252	281,665	71,962	8,387	1,507	0
18	385.00	IND M&R EQUIPMENT	5,047,477	0	202,303	929,846	2,085,214	1,830,114	0
19	385.00	DIRECT - IND M&R EQUIPMENT	373,291	0	0	0	0	0	373,291
20	385.10	IND M&R EQUIPMENT - LG VOLUME	1,151,820	0	46,165	212,188	475,840	417,627	0
21	387.10	OTHER EQUIP DISTRIBUTION	16,603	13,078	1,385	1,131	511	490	9
22	387.20	OTHER EQUIP ODORIZATION	117,248	92,349	9,781	7,988	3,607	3,462	61
23	387.42	OTHER EQUIP RADIO	121,945	96,049	10,173	8,308	3,751	3,601	63
24	387.44	OTHER EQUIP COMMUNICATION	635,499	500,545	53,013	43,297	19,548	18,766	331
25	387.46	OTHER EQUIP CUSTOMER INFO SERVICE	3,572,300	2,813,687	298,001	243,381	109,884	105,490	1,858
26	387.45	DIRECT - OTHER EQUIP CUSTOMER INFO SER	56,078	0	0	0	0	0	56,078
27	387.50	GPS EQUIPMENT	4,304,405	3,390,322	359,074	293,259	132,404	127,109	2,238
28	374-387	TOTAL DISTRIBUTION	2,141,859,442	1,686,979,784	178,663,472	145,919,883	65,880,656	63,244,131	1,171,518

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 12
GROSS PLANT

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
		GENERAL PLANT							
1	389.20	Land Rights	0						
2	390.10	Str, Communications	120,070						
3	391.10	OF&E Unspecified	2,757,359						
4	391.11	OF&E Data Handling Equipment	24,427						
5	391.12	OF&E Information Systems	1,860,012						
6	391.20	OF&E Air Cond Equip	3,007						
7	392.20	Trans Eq Trailers > $1,000	85,691						
8	392.21	Trans Eq Trailers $1,000 or >	10,830						
9	393.00	Stores Equipment	13,435						
10	394.10	Tools, Garage & Service Eq	100,115						
11	394.11	CNG Equip - Stationary	1,774,190						
12	394.12	CNG Equip - Portable	179,308						
13	394.20	Shop Equipment	66,773						
14	394.30	Tools & Other	14,794,442						
15	394.31	High Pressure Stopping	10,847						
16	395.00	Laboratory Equipment, Gas	27,903						
17	396.00	Power Operated Equipment	1,435,493						
18	397.00	Communication Equipment	0						
19	397.10	Communication Equipment-Telephone	1,200,001						
20	397.20	Communication Equipment-Radio	0						
21	397.40	Communication Equipment-Other	0						
22	397.50	Communication Equipment-Telemetering	2,029,340						
23	398.00	Miscellaneous Equipment	867,608						
24	389-398	TOTAL GENERAL PLANT	27,360,850	21,550,500	2,282,442	1,864,095	841,620	807,966	14,228
25		TOTAL	2,211,566,200	1,741,562,748	184,703,869	150,993,812	67,954,839	65,138,050	1,212,883
		ALLOCATOR #12		78.748%	8.352%	6.827%	3.073%	2.945%	0.055%

EXHIBIT MPB-2
ALLOC 13

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 13
DIRECT PLANT - MAINS

LINE NO.	ACCT. NO.	ACCOUNT	GROSS PLANT	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	376.00	MAINS	1,354,749,182	1,021,345,408	121,656,477	103,638,312	54,447,370	53,661,615	-
2	376.00	DIRECT - MAINS - MDS	226,885	-	-	-	-	-	226,885
3	376.08	MAINS-CSL REPLACEMENTS	23,785,876	17,932,172	2,135,972	1,819,620	955,954	942,159	-
4	376.30	MAINS-BARE STEEL	68,743,268	51,825,550	6,173,146	5,258,860	2,762,792	2,722,921	-
5	376.30	DIRECT - MAINS-BARE STEE	129,516	-	-	-	-	-	129,516
6	376.80	MAINS-CAST IRON	523,053	394,330	46,970	40,014	21,022	20,718	-
7		TOTAL	1,448,157,780	1,091,497,460	130,012,564	110,756,806	58,187,137	57,347,413	356,401
		ALLOCATOR #13	100.000%	75.371%	8.978%	7.648%	4.018%	3.960%	0.025%

EXHIBIT MPB-2
ALLOC 14

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 14
COMPOSITE DIRECT PLANT - ACCOUNTS 376 & 380

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	376.00	MAINS	1,354,749,182	1,021,345,408	121,656,477	103,638,312	54,447,370	53,661,615	-
2	376.00	DIRECT - MAINS - MDS	226,885	-	-	-	-	-	226,885
3	376.08	MAINS-CSL REPLACEMENTS	23,785,876	17,932,172	2,135,972	1,819,620	955,954	942,159	-
4	376.30	MAINS-BARE STEEL	68,743,268	51,825,550	6,173,146	5,258,860	2,762,792	2,722,921	-
5	376.30	DIRECT - MAINS-BARE STEEL	129,516	-	-	-	-	-	129,516
6	376.80	MAINS-CAST IRON	523,053	394,330	46,970	40,014	21,022	20,718	-
7	380.00	SERVICES	490,342,928	445,265,703	36,118,660	7,595,412	1,015,010	348,144	-
8	380.00	DIRECT - SERVICES	39,403	-	-	-	-	-	39,403
9	380.12	CSL REPLACEMENT	-	-	-	-	-	-	-
10		TOTAL	1,938,540,112	1,536,763,162	166,131,224	118,352,218	59,202,147	57,695,556	395,804
11		**ALLOCATOR #14**	100.000%	79.275%	8.570%	6.105%	3.054%	2.976%	0.020%

Columbia Gas of Pennsylvania, Inc.
Services Allocation Factor
As of November 30, 2015

Billing Rate	Rate Case Rate	Classification	BLANK	P	S	*	±	Total	Average Unit Cost	Total Cost	Key
801	SDS/LGSS	6"	0	0	0	0	1	1	2,570.20	2,570.20	8016"
802	MDS/NSS	8"	0	0	0	1	1	2	5,594.69	11,189.38	8028"
803	LDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	803UNDER 3"
806	SDS/LGSS	3"	1	0	0	0	0	1	470.89	470.89	8063"
806	SDS/LGSS	4"	1	0	0	0	0	1	2,424.69	2,424.69	8064"
806	SDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	806UNDER 3"
808	LDS/LGSS	6-5/8"	0	0	0	1	0	1	883.31	883.31	8086-5/8"
808	LDS/LGSS	UNDER 3"	0	0	0	0	1	1	837.35	837.35	808UNDER 3"
809	LDS/LGSS	6"	1	0	0	0	0	1	2,570.20	2,570.20	8096"
809	LDS/LGSS	8"	0	0	0	1	0	1	5,594.69	5,594.69	8098"
810	LDS/LGSS	6"	1	0	0	0	0	1	2,570.20	2,570.20	8106"
816	LDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	816UNDER 3"
819	LDS/LGSS	6"	1	0	0	0	0	1	2,570.20	2,570.20	8196"
820	LDS/LGSS	UNDER 3"	0	0	0	1	0	1	837.35	837.35	820UNDER 3"
821	MDS/NSS	8"	1	0	0	0	0	1	5,594.69	5,594.69	8218"
830	LDS/LGSS	4"	1	0	0	0	0	1	2,424.69	2,424.69	8304"
830	LDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	830UNDER 3"
831	MDS/NSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	831UNDER 3"
833	LDS/LGSS	8"	0	0	0	0	1	1	5,594.69	5,594.69	8338"
838	SDS/LGSS	4"	0	0	0	1	0	1	2,424.69	2,424.69	8384"
840	LDS/LGSS	4"	1	0	0	0	0	1	2,424.69	2,424.69	8404"
840	LDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	840UNDER 3"
841	SGSS2/SCD2/SGDS2	UNDER 3"	1	0	0	0	0	1	837.35	837.35	841UNDER 3"
845	LDS/LGSS	4"	1	0	0	0	0	1	2,424.69	2,424.69	8454"
846	LDS/LGSS	6"	0	0	0	0	1	1	2,570.20	2,570.20	8466"
846	LDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	846UNDER 3"
847	SDS/LGSS	4"	1	0	0	0	0	1	2,424.69	2,424.69	8474"
848	SGSS2/SCD2/SGDS2	UNDER 3"	1	0	0	0	0	1	837.35	837.35	848UNDER 3"
850	MDS/NSS	4"	0	0	0	1	0	1	2,424.69	2,424.69	8504"
852	SGSS2/SCD2/SGDS2	4"	4	0	0	0	0	4	2,424.69	9,698.76	8524"
852	SGSS2/SCD2/SGDS2	UNDER 3"	18	0	0	0	0	18	837.35	15,072.30	852UNDER 3"
853	SGSS2/SCD2/SGDS2	UNDER 3"	13	0	0	0	0	13	837.35	10,885.55	853UNDER 3"
854	SGSS2/SCD2/SGDS2	UNDER 3"	16	0	0	0	0	16	837.35	13,397.60	854UNDER 3"
855	SGSS2/SCD2/SGDS2	UNDER 3"	4	0	0	1	4	9	837.35	7,536.15	855UNDER 3"
856	SDS/LGSS	4"	1	0	0	0	0	1	2,424.69	2,424.69	8564"
857	SGSS2/SCD2/SGDS2	3"	1	0	0	0	0	1	470.89	470.89	8573"
858	SDS/LGSS	4"	1	0	0	0	0	1	2,424.69	2,424.69	8584"
859	LDS/LGSS	4"	0	0	0	1	0	1	2,424.69	2,424.69	8594"
860	SGSS2/SCD2/SGDS2	UNDER 3"	1	0	0	0	0	1	837.35	837.35	860UNDER 3"
861	SDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	861UNDER 3"

862	SGSS1/SCD1/SGDS1	UNDER 3"	1	0	0	0	0	1	837.35	837.35	862UNDER 3"
863	SGSS2/SCD2/SGDS2	UNDER 3"	1	0	0	0	0	1	837.35	837.35	863UNDER 3"
864	SGSS1/SCD1/SGDS1	UNDER 3"	1	0	0	0	0	1	837.35	837.35	864UNDER 3"
865	SDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	865UNDER 3"
866	SGSS1/SCD1/SGDS1	UNDER 3"	1	0	0	0	0	1	837.35	837.35	866UNDER 3"
868	LDS/LGSS	UNDER 3"	0	0	0	1	1	2	837.35	1,674.70	868UNDER 3"
872	MDS/NSS	3"	1	0	0	0	0	1	470.89	470.89	8723"
873	LDS/LGSS	6"	1	0	0	0	0	1	2,570.20	2,570.20	8736"
874	SDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	874UNDER 3"
875	LDS/LGSS	6"	1	0	0	1	1	3	2,570.20	7,710.60	8756"
875	LDS/LGSS	8"	0	0	0	1	0	1	5,594.69	5,594.69	8758"
875	LDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	875UNDER 3"
876	SDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	876UNDER 3"
877	SGSS2/SCD2/SGDS2	UNDER 3"	1	0	0	0	0	1	837.35	837.35	877UNDER 3"
878	MDS/NSS	4"	0	0	0	1	0	1	2,424.69	2,424.69	8784"
879	SDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	879UNDER 3"
LG1	SDS/LGSS	3"	1	0	0	1	1	3	470.89	1,412.67	LG13"
LG1	SDS/LGSS	4"	6	0	0	2	1	9	2,424.69	21,822.21	LG14"
LG1	SDS/LGSS	6"	0	0	0	1	0	1	2,570.20	2,570.20	LG16"
LG1	SDS/LGSS	UNDER 3"	34	0	1	7	3	45	837.35	37,680.75	LG1UNDER 3"
LG2	SDS/LGSS	3"	6	0	0	1	0	7	470.89	3,296.23	LG23"
LG2	SDS/LGSS	4"	6	0	0	2	1	9	2,424.69	21,822.21	LG24"
LG2	SDS/LGSS	6"	0	0	0	1	0	1	2,570.20	2,570.20	LG26"
LG2	SDS/LGSS	UNDER 3"	57	0	5	7	2	71	837.35	59,451.85	LG2UNDER 3"
LG3	LDS/LGSS	3"	1	0	0	0	0	1	470.89	470.89	LG33"
LG3	LDS/LGSS	4"	1	0	0	0	0	1	2,424.69	2,424.69	LG34"
LG3	LDS/LGSS	UNDER 3"	2	0	0	0	0	2	837.35	1,674.70	LG3UNDER 3"
LG4	LDS/LGSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	LG4UNDER 3"
NSI	MDS/NSS	3"	1	0	0	0	0	1	470.89	470.89	NSI3"
RCC	RSS/RTS	3"	2	0	0	1	0	3	470.89	1,412.67	RCC3"
RCC	RSS/RTS	4"	4	0	0	0	0	4	2,424.69	9,698.76	RCC4"
RCC	RSS/RTS	6"	1	0	0	0	0	1	2,570.20	2,570.20	RCC6"
RCC	RSS/RTS	8"	1	0	0	0	0	1	5,594.69	5,594.69	RCC8"
RCC	RSS/RTS	UNDER 3"	15,862	151	98	2,444	2,443	20,998	837.35	17,582,675.30	RCCUNDER 3"
RS	RSS/RTS	3"	17	1	0	5	42	65	470.89	30,607.85	RS3"
RS	RSS/RTS	4"	13	1	1	4	39	58	2,424.69	140,632.02	RS4"
RS	RSS/RTS	5"	2	0	0	0	0	2	1,020.80	2,041.60	RS5"
RS	RSS/RTS	6"	6	0	0	1	0	7	2,570.20	17,991.40	RS6"
RS	RSS/RTS	8"	18	0	0	2	0	20	5,594.69	111,893.80	RS8"
RS	RSS/RTS	UNDER 3"	230,896	1,519	1,432	19,996	28,174	282,017	837.35	236,146,934.95	RSUNDER 3"
RTC	RSS/RTS	3"	7	0	0	2	6	15	470.89	7,063.35	RTC3"
RTC	RSS/RTS	4"	4	0	0	1	6	11	2,424.69	26,671.59	RTC4"
RTC	RSS/RTS	5"	1	1	0	0	0	2	1,020.80	2,041.60	RTC5"
RTC	RSS/RTS	6"	1	0	0	0	0	1	2,570.20	2,570.20	RTC6"
RTC	RSS/RTS	UNDER 3"	74,601	438	398	4,292	4,297	84,026	837.35	70,359,171.10	RTCUNDER 3"
SC2	SGSS2/SCD2/SGDS2	3"	18	0	0	2	1	21	470.89	9,888.69	SC23"

SC2	SGSS2/SCD2/SGDS2	4"	10	0	0	0	0	10	2,424.69	24,246.90	SC24"
SC2	SGSS2/SCD2/SGDS2	6"	2	0	0	2	0	4	2,570.20	10,280.80	SC26"
SC2	SGSS2/SCD2/SGDS2	6-5/8"	2	0	0	0	0	2	883.31	1,766.62	SC26-5/8"
SC2	SGSS2/SCD2/SGDS2	8"	1	0	0	0	0	1	5,594.69	5,594.69	SC28"
SC2	SGSS2/SCD2/SGDS2	UNDER 3"	681	7	4	123	67	882	837.35	738,542.70	SC2UNDER 3"
SCC	SGSS1/SCD1/SGDS1	3"	9	1	0	10	14	34	470.89	16,010.26	SCC3"
SCC	SGSS1/SCD1/SGDS1	4"	7	0	0	4	4	15	2,424.69	36,370.35	SCC4"
SCC	SGSS1/SCD1/SGDS1	5"	0	0	0	0	2	2	1,020.80	2,041.60	SCC5"
SCC	SGSS1/SCD1/SGDS1	UNDER 3"	4,655	45	47	1,464	1,410	7,621	837.35	6,381,444.35	SCCUNDER 3"
SG2	SGSS2/SCD2/SGDS2	3"	76	0	0	6	7	89	470.89	41,909.21	SG23"
SG2	SGSS2/SCD2/SGDS2	4"	73	0	0	10	8	91	2,424.69	220,646.79	SG24"
SG2	SGSS2/SCD2/SGDS2	5"	0	0	0	0	1	1	1,020.80	1,020.80	SG25"
SG2	SGSS2/SCD2/SGDS2	6"	3	0	0	0	0	3	2,570.20	7,710.60	SG26"
SG2	SGSS2/SCD2/SGDS2	UNDER 3"	2,683	14	21	399	279	3,396	837.35	2,843,640.60	SG2UNDER 3"
SG3	SGSS1/SCD1/SGDS1	3"	1	0	0	0	0	1	470.89	470.89	SG33"
SG3	SGSS1/SCD1/SGDS1	4"	1	0	0	2	0	3	2,424.69	7,274.07	SG34"
SG3	SGSS1/SCD1/SGDS1	6"	1	0	0	0	0	1	2,570.20	2,570.20	SG36"
SG3	SGSS1/SCD1/SGDS1	UNDER 3"	13	0	0	1	0	14	837.35	11,722.90	SG3UNDER 3"
SG4	SGSS2/SCD2/SGDS2	3"	3	0	0	1	0	4	470.89	1,883.56	SG43"
SG4	SGSS2/SCD2/SGDS2	4"	3	0	0	2	0	5	2,424.69	12,123.45	SG44"
SG4	SGSS2/SCD2/SGDS2	6"	1	0	0	0	0	1	2,570.20	2,570.20	SG46"
SG4	SGSS2/SCD2/SGDS2	UNDER 3"	22	0	0	3	1	26	837.35	21,771.10	SG4UNDER 3"
SGS	SGSS1/SCD1/SGDS1	3"	36	0	0	32	49	117	470.89	55,094.13	SGS3"
SGS	SGSS1/SCD1/SGDS1	4"	30	0	0	15	25	70	2,424.69	169,728.30	SGS4"
SGS	SGSS1/SCD1/SGDS1	6"	4	0	0	0	0	4	2,570.20	10,280.80	SGS6"
SGS	SGSS1/SCD1/SGDS1	UNDER 3"	12,520	128	105	4,407	5,597	22,757	837.35	19,055,573.95	SGSUNDER 3"
SGS	SGSS1/SCD1/SGDS1	8"	1	0	0	0	0	1	5,594.69	5,594.69	SGS8"
TAG1	SGSS1/SCD1/SGDS1	UNDER 3"	41	0	0	5	13	59	837.35	49,403.65	TAG1UNDER 3"
TAG1	SGSS1/SCD1/SGDS1	4"	1	0	0	0	0	1	2,424.69	2,424.69	TAG14"
TAG2	SGSS2/SCD2/SGDS2	3"	16	0	0	1	0	17	470.89	8,005.13	TAG23"
TAG2	SGSS2/SCD2/SGDS2	4"	13	0	0	3	0	16	2,424.69	38,795.04	TAG24"
TAG2	SGSS2/SCD2/SGDS2	6"	1	0	0	0	0	1	2,570.20	2,570.20	TAG26"
TAG2	SGSS2/SCD2/SGDS2	UNDER 3"	234	1	0	30	21	286	837.35	239,482.10	TAG2UNDER 3"
TAG5	SGSS1/SCD1/SGDS1	3"	7	0	0	1	3	11	470.89	5,179.79	TAG53"
TAG5	SGSS1/SCD1/SGDS1	4"	8	0	0	1	2	11	2,424.69	26,671.59	TAG54"
TAG5	SGSS1/SCD1/SGDS1	UNDER 3"	399	2	0	69	99	569	837.35	476,452.15	TAG5UNDER 3"
TAG6	SGSS2/SCD2/SGDS2	3"	54	0	0	5	2	61	470.89	28,724.29	TAG63"
TAG6	SGSS2/SCD2/SGDS2	4"	53	1	0	6	2	62	2,424.69	150,330.78	TAG64"
TAG6	SGSS2/SCD2/SGDS2	6"	5	0	0	3	0	8	2,570.20	20,561.60	TAG66"
TAG6	SGSS2/SCD2/SGDS2	UNDER 3"	1,060	10	5	112	58	1,245	837.35	1,042,500.75	TAG6UNDER 3"
TI4	SDS/LGSS	3"	22	0	0	2	1	25	470.89	11,772.25	TI43"
TI4	SDS/LGSS	4"	21	0	0	3	0	24	2,424.69	58,192.56	TI44"
TI4	SDS/LGSS	6"	4	0	0	2	1	7	2,570.20	17,991.40	TI46"
TI4	SDS/LGSS	UNDER 3"	165	1	1	12	6	185	837.35	154,909.75	TI4UNDER 3"
TI8	LDS/LGSS	3"	6	0	0	0	0	6	470.89	2,825.34	TI83"
TI8	LDS/LGSS	4"	14	0	0	3	0	17	2,424.69	41,219.73	TI84"

TI8	LDS/LGSS	6"	2	0	0	0	0	2	2,570.20	5,140.40	TI86"
TI8	LDS/LGSS	8"	0	1	1	0	0	2	5,594.69	11,189.38	TI88"
TI8	LDS/LGSS	UNDER 3"	24	0	0	3	3	30	837.35	25,120.50	TI8UNDER 3"
TIB	SDS/LGSS	3"	35	0	0	2	0	37	470.89	17,422.93	TIB3"
TIB	SDS/LGSS	4"	54	0	1	8	1	64	2,424.69	155,180.16	TIB4"
TIB	SDS/LGSS	6"	6	0	0	0	0	6	2,570.20	15,421.20	TIB6"
TIB	SDS/LGSS	8"	1	0	0	0	0	1	5,594.69	5,594.69	TIB8"
TIB	SDS/LGSS	UNDER 3"	134	2	0	21	3	160	837.35	133,976.00	TIBUNDER 3"
TIF	LDS/LGSS	3"	10	0	0	1	0	11	470.89	5,179.79	TIF3"
TIF	LDS/LGSS	4"	11	0	0	0	0	11	2,424.69	26,671.59	TIF4"
TIF	LDS/LGSS	6"	2	0	0	0	0	2	2,570.20	5,140.40	TIF6"
TIF	LDS/LGSS	8"	1	0	0	0	0	1	5,594.69	5,594.69	TIF8"
TIF-EFACT	LDS/LGSS	4"	1	0	0	0	0	1	2,424.69	2,424.69	TIF-EFACT4"
TIF	LDS/LGSS	UNDER 3"	46	1	1	3	2	53	837.35	44,379.55	TIFUNDER 3"
TIG	LDS/LGSS	3"	1	0	0	0	0	1	470.89	470.89	TIG3"
TIG	LDS/LGSS	4"	1	0	0	0	0	1	2,424.69	2,424.69	TIG4"
TIG	LDS/LGSS	6"	1	0	0	0	0	1	2,570.20	2,570.20	TIG6"
TIG	LDS/LGSS	8"	0	0	0	1	0	1	5,594.69	5,594.69	TIG8"
TIG	LDS/LGSS	UNDER 3"	2	0	0	0	0	2	837.35	1,674.70	TIGUNDER 3"
TIH	LDS/LGSS	6"	1	0	0	0	0	1	2,570.20	2,570.20	TIH6"
TM2	MDS/NSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	TM2UNDER 3"
TM3	MDS/NSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	TM3UNDER 3"
TMA	MDS/NSS	UNDER 3"	1	0	0	0	0	1	837.35	837.35	TMAUNDER 3"
UNKNOWN			2,256	15	24	477	895	3,667	UNKNOWN	UNKNOWN	UNKNOWN
			347,216	2,340	2,145	34,039	43,603	429,343		357,321,306.92	

		Total Cost	Percent
	RSS/RTS	324,449,571.08	90.807%
	SGSS1/SCD1/SGDS1	26,316,820.41	7.366%
	SGSS2/SCD2/SGDS2	5,535,814.60	1.549%
	SDS/LGSS	741,275.90	0.207%
	LDS/LGSS	251,900.30	0.071%
	TOTAL BEFORE MDS/NSS	357,295,382.29	100.000%
	MDS/NSS	25,924.63	
	TOTAL	357,321,306.92	
	UNKNOWN	54,000,118.79	
101-1000	TOTAL ACCOUNT 380	411,321,425.71	
101-2000	CIAC	(1,272,483)	
101-4000	Relocation Reimbursements	(17,664)	
106	Completed Construction not Classified	590,903	
Total	Per Exhibit 8, Schedule 1	410,622,182	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 16
METERS

LINE NO.	RATE CODE	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS	TOTAL
		$	$	$	$	$	$	$
1	801	0	0	0	464	0	0	464
2	802	0	0	0	0	0	929	929
3	803	0	0	0	0	464	0	464
4	806	0	0	0	1,439	0	0	1,439
5	808	0	0	0	0	929	0	929
6	809	0	0	0	0	929	0	929
7	810	0	0	0	0	464	0	464
8	816	0	0	0	0	464	0	464
9	819	0	0	0	0	464	0	464
10	820	0	0	0	0	464	0	464
11	821	0	0	0	0	0	464	464
12	830	0	0	0	0	975	0	975
13	831	0	0	0	0	0	464	464
14	833	0	0	0	0	464	0	464
15	838	0	0	0	0	464	0	464
16	840	0	0	0	0	929	0	929
17	841	0	0	464	0	0	0	464
18	845	0	0	0	0	464	0	464
19	846	0	0	0	0	929	0	929
20	847	0	0	0	464	0	0	464
21	848	0	0	464	0	0	0	464
22	850	0	0	0	0	0	464	464
23	852	0	1,122	8,169	0	0	0	9,290
24	853	0	1,071	3,691	0	0	0	4,762
25	854	0	50	5,875	0	0	0	5,925
26	855	0	813	975	0	0	0	1,788
27	856	0	0	0	464	0	0	464
28	857	0	0	464	0	0	0	464
29	858	0	0	0	464	0	0	464
30	859	0	0	0	0	464	0	464
31	860	0	0	464	0	0	0	464
32	861	0	0	0	464	0	0	464
33	862	0	510	0	0	0	0	510
34	863	0	0	510	0	0	0	510
35	864	0	510	0	0	0	0	510
36	865	0	0	0	464	0	0	464
37	866	0	510	0	0	0	0	510
38	868	0	0	0	0	929	0	929
39	872	0	0	0	0	0	464	464
40	873	0	0	0	0	464	0	464
41	874	0	0	0	464	0	0	464
42	875	0	0	0	0	1,858	0	1,858
43	876	0	0	0	464	0	0	464
44	877	0	0	464	0	0	0	464
45	878	0	0	0	0	0	464	464
46	879	0	0	0	464	0	0	464
47	LG1	0	0	0	29,205	0	0	29,205
48	LG2	0	0	0	40,870	0	0	40,870
49	LG3	0	0	0	0	1,858	0	1,858
50	LG4	0	0	0	0	1,393	0	1,393
51	LG5	0	0	0	0	464	0	464
52	NSI	0	0	0	0	0	50	50

53	RCC	1,043,505	0	0	0	0	0	1,043,505
54	RGC	0	0	0	0	0	0	0
55	RGS	0	0	0	0	0	0	0
56	RS	14,439,977	0	0	0	0	0	14,439,977
57	RTC	4,232,964	0	0	0	0	0	4,232,964
58	SCC	0	853,258	0	0	0	0	853,258
59	SC2	0		340,133	0	0	0	340,133
60	SG2	0		1,495,048	0	0	0	1,495,048
61	SG3	0	8,028	0	0	0	0	8,028
62	SG4	0	17,453	0	0	0	0	17,453
63	SGS	0		2,744,473	0	0	0	2,744,473
64	TAG1	0	23,267	0	0	0	0	23,267
65	TAG2	0		142,969	0	0	0	142,969
66	TAG5	0	159,322	0	0	0	0	159,322
67	TAG6	0		594,003	0	0	0	594,003
68	TI4	0	0	0	68,738	0	0	68,738
69	TI8	0	0	0	0	24,933	0	24,933
70	TIB	0	0	0	122,660	0	0	122,660
71	TIF	0	0	0	0	30,792	0	30,792
72	TIF-EFACT	0	0	0	0	464	0	464
73	TIG	0	0	0	0	2,550	0	2,550
74	TIH	0	0	0	0	464	0	464
75	TM1	0	0	0	0	0	0	0
76	TM2	0	0	0	0	0	455	455
77	TMA	0	0	0	0	0	464	464
78	TOTAL	19,716,446	1,065,916	5,338,167	267,092	75,039	4,221	26,466,882
79	**ALLOCATOR #16**	74.495%	4.027%	20.169%	1.009%	0.284%	0.016%	100.000%

Columbia Gas of Pennsylvania, Inc.
Account 385 Industrial Measurment Stations
As of November 30, 2015

Co	PCID	PSID	Tar Rate	GTS Rate	Station No.	Tax District	Name	Amt	Billing Rate	Rate Class
37	10034190010	501054825	SGT	TI4	49103	30209		10,256.77	TI4	SDS/LGSS
37	10047952001	400188814	SGT	TI4	45529	30243		17,823.82	TI4	SDS/LGSS
37	10094014002	400514870	SG2		1109	30298		1,977.24	SG2	SGSS2/SCD2/SGDS2
37	10098619004	400201038	SGT	TAG6	49083	30224		1,718.88	TAG6	SGSS2/SCD2/SGDS2
37	10104024001	400204209	SGT	TAG2	45723	30224		1,718.88	TAG2	SGSS2/SCD2/SGDS2
37	10107730026	400228748	SGT	TI4	47759	30236		9,447.49	TI4	SDS/LGSS
37	10119305004	400215304	SGT	TI4	45601	30224		1,718.88	TI4	SDS/LGSS
37	10119305004	400458788	SGT	TI4	45600	30224		1,718.88	TI4	SDS/LGSS
37	10348091005	400518175	SG4		44452	1333017		5,569.25	SG4	SGSS2/SCD2/SGDS2
37	10375621158	500489101	SGT	TI4	47567	1333032		11,290.77	TI4	SDS/LGSS
37	10379912006	400498094	SG4		14628	1333032		5,938.10	SG4	SGSS2/SCD2/SGDS2
37	10389296002	400511162	SGT	TAG6	4135	1333095		281.27	TAG6	SGSS2/SCD2/SGDS2
37	10405620001	400044475	SGT	TAG6	45746	1333095		11,399.49	TAG6	SGSS2/SCD2/SGDS2
37	10416756005	500065176	SG2		47085	1333063		717.31	SG2	SGSS2/SCD2/SGDS2
37	10421482002	500617033	SGT	TI8	49153	551504		47,235.90	TI8	LDS/LGSS
37	10422436002	400343911	SGT	TIB	46123	10155		4,383.45	TIB	SDS/LGSS
37	10468703002	400525452	SGT	861	48454	1292914		19,884.30	861	SDS/LGSS
37	10474924002	400303837	SGS		48831	1292988		967.26	SGS	SGSS1/SCD1/SGDS1
37	10501013005	400511506	SGT	TAG6	1276	511316		2,306.59	TAG6	SGSS2/SCD2/SGDS2
37	10534828042	400252907	SGT	TIB	48310	1252865		0.00	TIB	SDS/LGSS
37	10534828042	400254200	SGT	TIB	45786	1252865		0.00	TIB	SDS/LGSS
37	10534828042	400526993	SGT	TIB	45669	1252865		0.00	TIB	SDS/LGSS
37	10534828042	500159589	SGT	TIB	46124	1252896		2,800.24	TIB	SDS/LGSS
37	10534828042	800800427	SGT	TIB	3423	1252896		1,865.65	TIB	SDS/LGSS
37	10534828042	800800428	SGT	TIB	44621	1252896		2,800.24	TIB	SDS/LGSS
37	10534828042	800800429	SGT	TIB	44622	1252896		2,800.24	TIB	SDS/LGSS
37	10534828042	800800430	SGT	TIB	44623	1252896		2,800.24	TIB	SDS/LGSS
37	10534828042	800800436	SGT	TIB	44629	1252896		2,800.24	TIB	SDS/LGSS
37	11654473003	500030237	SGT	TIB	48810	1232756		9,184.43	TIB	SDS/LGSS
37	11674720002	800800405	SG2		4236	30268		1,860.45	SG2	SGSS2/SCD2/SGDS2
37	12983110001	400473519	SGS		662	1232704		803.97	SGS	SGSS1/SCD1/SGDS1
37	12983111001	400473518	SGT	TIB	661	1232704		20,610.83	TIB	SDS/LGSS
37	12983117001	400473502	SG2		3239	1232718		926.86	SG2	SGSS2/SCD2/SGDS2
37	12983120001	400479735	SGS		14245	1232756		4,516.53	SGS	SGSS1/SCD1/SGDS1
37	12983124002	400473470	SG3		593	832295		4,846.78	SG3	SGSS1/SCD1/SGDS1
37	12983149001	800800461	SGT	TAG6	14545	1292906		5,738.98	TAG6	SGSS2/SCD2/SGDS2
37	12983153001	800800460	SGT	TI4	1414	1292906		6,959.69	TI4	SDS/LGSS
37	12983156001	800800458	SGT	TAG6	1268	1292906		1,708.84	TAG6	SGSS2/SCD2/SGDS2
37	12983176001	400490973	SGT	TAG6	14491	1292969		3,560.97	TAG6	SGSS2/SCD2/SGDS2
37	12983177001	400484946	LG1		14324	1292906		855.29	LG1	SDS/LGSS
37	12983182001	400473449	SG2		3416	1292977		1,207.92	SG2	SGSS2/SCD2/SGDS2
37	12983191002	400473426	SGT	TAG6	1444	511312		6,974.42	TAG6	SGSS2/SCD2/SGDS2
37	12983192001	400473425	SGT	TI4	1443	511396		6,156.09	TI4	SDS/LGSS
37	12983199002	400473414	SGT2	TAG6	1434	511318		5,116.21	TAG6	SGSS2/SCD2/SGDS2
37	12983205001	400473388	SG2		4299	511314		5,425.75	SG2	SGSS2/SCD2/SGDS2
37	12983206002	500135694	SGT	TI4	1405	511314		7,495.20	TI4	SDS/LGSS
37	12983208001	400473368	SG2		4584	511314		2,944.67	SG2	SGSS2/SCD2/SGDS2
37	12983210001	400473364	SGT	TAG6	4614	511314		2,618.96	TAG6	SGSS2/SCD2/SGDS2
37	12983212001	400473357	SGT	TAG6	4548	511395		15,160.98	TAG6	SGSS2/SCD2/SGDS2
37	12983214001	400473355	SGT	TAG6	4715	511304		1,630.16	TAG6	SGSS2/SCD2/SGDS2
37	12983215001	400473354	SGT	TAG6	1377	1292913		936.34	TAG6	SGSS2/SCD2/SGDS2
37	12983225001	400473325	SG2		1352	511314		4,242.54	SG2	SGSS2/SCD2/SGDS2
37	12983232001	400473302	SGT	TAG6	1335	511320		4,728.84	TAG6	SGSS2/SCD2/SGDS2
37	12983235001	800800451	SGT	TAG6	1331	511306		2,469.81	TAG6	SGSS2/SCD2/SGDS2
37	12983239001	400473287	SGT	TAG2	1323	511314		3,777.32	TAG2	SGSS2/SCD2/SGDS2
37	12983242001	400473279	SG2		1318	511303		2,708.28	SG2	SGSS2/SCD2/SGDS2

37	12983255002	400514019	SGT	TIB	1291	511395	1,465.00	TIB	SDS/LGSS
37	12983255002	500135582	SGT	TIB	1291	511395	1,465.00	TIB	SDS/LGSS
37	12983259002	400473238	SGT	TIB	1280	511396	3,429.15	TIB	SDS/LGSS
37	12983259002	500135609	SGT	TIB	1280	511396	3,429.15	TIB	SDS/LGSS
37	12983262001	400513746	SGT	TI8	44092	511363	2,455.94	TI8	LDS/LGSS
37	12983265002	400473216	SGS		1262	511395	4,076.87	SGS	SGSS1/SCD1/SGDS1
37	12983275001	400473402	SGT	TI4	1423	1112553	2,623.48	TI4	SDS/LGSS
37	12983276001	400473401	SGT	TI8	3382	1112553	16,093.80	TI8	LDS/LGSS
37	12983281001	400473412	SG2		1432	1112521	3,135.76	SG2	SGSS2/SCD2/SGDS2
37	12983282001	400473411	SGT	TIB	1431	1112569	5,337.78	TIB	SDS/LGSS
37	12983287001	400473405	SGT	TI4	1426	1112521	7,975.76	TI4	SDS/LGSS
37	12983292002	400473346	LG1		1372	1112561	8,314.06	LG1	SDS/LGSS
37	12983293002	400473347	SGT	TI4	448	1112524	2,828.39	TI4	SDS/LGSS
37	12983297001	400473265	SGT	TIB	1302	1112569	9,980.77	TIB	SDS/LGSS
37	12983298001	400473267	SGT	TI4	1305	1112569	1,771.37	TI4	SDS/LGSS
37	12983301001	400473229	SGT	TI4	4252	1112553	1,853.55	TI4	SDS/LGSS
37	12983302001	400502918	SG2		4492	1112521	1,179.62	SG2	SGSS2/SCD2/SGDS2
37	12983314001	400473452	SGT	TAG6	1467	1292918	3,121.92	TAG6	SGSS2/SCD2/SGDS2
37	12983315001	400473443	SG2		4413	1292998	1,427.28	SG2	SGSS2/SCD2/SGDS2
37	12983318001	400473440	SGT	TAG6	1456	1292909	2,977.62	TAG6	SGSS2/SCD2/SGDS2
37	12983325001	400511507	SGT	TAG6	1403	1292914	2,918.17	TAG6	SGSS2/SCD2/SGDS2
37	12983331001	400473315	SGT	TAG6	4471	1292989	7,328.56	TAG6	SGSS2/SCD2/SGDS2
37	12983343001	400512909	SGT	TMA	3295	1252863	5,426.90	TMA	MDS/NSS
37	12983344001	400497701	SGT	TAG6	1469	1292986	1,721.17	TAG6	SGSS2/SCD2/SGDS2
37	12983347001	400473439	SGT	TI4	4539	1252805	1,813.88	TI4	SDS/LGSS
37	12983348001	400504725	SGT	TI4	1363	1252858	1,728.41	TI4	SDS/LGSS
37	12983349001	400473387	SG2		1408	1252858	1,774.66	SG2	SGSS2/SCD2/SGDS2
37	12983352001	400473370	SGT	TI4	1386	511365	2,837.20	TI4	SDS/LGSS
37	12983354001	400473366	SGT	TAG6	4044	1292919	1,330.60	TAG6	SGSS2/SCD2/SGDS2
37	12983355011	400473369	SGT	TIB	4469	1252855	2,953.96	TIB	SDS/LGSS
37	12983355011	400484838	SGT	TIB	14322	1252855	5,698.48	TIB	SDS/LGSS
37	12983355011	500163677	SGT	TIB	47388	1252855	0.00	TIB	SDS/LGSS
37	12983355011	500287938	SGT	TIB	47386	1252855	0.00	TIB	SDS/LGSS
37	12983359001	400473342	SGT	TIB	1364	1252858	2,376.04	TIB	SDS/LGSS
37	12983370001	400495171	SG2		3323	1252863	4,538.11	SG2	SGSS2/SCD2/SGDS2
37	12983372001	400473241	SGT	TAG6	4286	1252855	1,327.67	TAG6	SGSS2/SCD2/SGDS2
37	12983374001	400473233	SGT	TAG6	1275	511311	1,137.23	TAG6	SGSS2/SCD2/SGDS2
37	12983375002	400473232	SGT	TI4	1274	511311	11,004.89	TI4	SDS/LGSS
37	12983378001	400473230	SGT	TAG6	1273	1252862	(1,467.53)	TAG6	SGSS2/SCD2/SGDS2
37	12983384001	400499203	SGT	TAG6	14606	732111	1,522.62	TAG6	SGSS2/SCD2/SGDS2
37	12983391001	400472970	SGT	TAG2	4430	732195	1,191.65	TAG2	SGSS2/SCD2/SGDS2
37	12983397001	400472931	LG1		4529	732113	25,869.07	LG1	SDS/LGSS
37	12983400001	400472869	SGS		744	732113	2,112.84	SGS	SGSS1/SCD1/SGDS1
37	12983403001	400472841	SGT	TI8	718	732195	10,534.65	TI8	LDS/LGSS
37	12983415001	400473189	SGT	TI8	1005	732158	9,302.44	TI8	LDS/LGSS
37	12983428001	400502425	SGT	816	14126	732153	648.88	816	LDS/LGSS
37	12983429002	400472946	SGT	TIB	807	70409	9,918.75	TIB	SDS/LGSS
37	12983433001	400512973	SGT	810	44075	732195	12,600.45	810	LDS/LGSS
37	12983434002	400472904	SGT	808	776	732153	13,295.18	808	LDS/LGSS
37	12983434002	500146396	SGT	808	776	732153	13,295.18	808	LDS/LGSS
37	12983434005	400512908	SGS		48469	732195	43,175.06	SGS	SGSS1/SCD1/SGDS1
37	12983443002	400488177	SGT	TIB	14348	732153	9,005.38	TIB	SDS/LGSS
37	12983450001	400473185	SG2		1002	732153	1,107.88	SG2	SGSS2/SCD2/SGDS2
37	12983451001	400473180	SGT	TI4	997	732114	10,025.00	TI4	SDS/LGSS
37	12983453001	400473149	SGT	TAG6	974	732111	3,928.47	TAG6	SGSS2/SCD2/SGDS2
37	12983461001	400475092	SGT	TIB	898	70418	3,400.60	TIB	SDS/LGSS
37	12983462001	400473064	SGT	TAG6	893	732195	1,986.01	TAG6	SGSS2/SCD2/SGDS2
37	12983465001	400473060	SGT	TIB	890	732113	2,137.80	TIB	SDS/LGSS
37	12983467002	400473014	SGT	TI8	856	70409	6,293.59	TI8	LDS/LGSS
37	12983472003	500146321	SGT	TIB	3440	732153	2,223.95	TIB	SDS/LGSS
37	12983473001	400472996	SGT	TI4	842	732195	2,687.80	TI4	SDS/LGSS
37	12983474002	400472983	SGT	TI8	832	732195	14,702.11	TI8	LDS/LGSS

37	12983474007	400473130	SGT	TIB	4242	732195	2,855.81	TIB	SDS/LGSS
37	12983476001	400472976	SGT	TAG2	827	732153	1,663.66	TAG2	SGSS2/SCD2/SGDS2
37	12983477001	400472975	SGT	TAG2	826	732195	2,722.41	TAG2	SGSS2/SCD2/SGDS2
37	12983480002	400472971	SGT	TAG2	746	732195	2,473.69	TAG2	SGSS2/SCD2/SGDS2
37	12983481001	400472949	SGT	TIB	809	732195	5,063.97	TIB	SDS/LGSS
37	12983483001	400526340	SG2		4234	70409	1,167.65	SG2	SGSS2/SCD2/SGDS2
37	12983487001	400472861	SG2		737	732195	1,137.35	SG2	SGSS2/SCD2/SGDS2
37	12983498005	800800442	SGT	TIB	4410	70458	5,290.09	TIB	SDS/LGSS
37	12983504001	400473099	SGT	TIB	924	70451	13,074.52	TIB	SDS/LGSS
37	12983508002	400508899	SGT	TI8	871	70424	9,181.24	TI8	LDS/LGSS
37	12983513001	400472886	SGT	TIB	760	70471	3,695.06	TIB	SDS/LGSS
37	12983515001	400472854	SGT	TI4	733	70471	2,660.89	TI4	SDS/LGSS
37	12983516001	400472826	SGT	TIB	708	70470	2,464.06	TIB	SDS/LGSS
37	12983517002	400505175	SGT	820	14699	70468	25,410.28	820	LDS/LGSS
37	12983537001	400473198	LG2		1013	70453	2,943.45	LG2	SDS/LGSS
37	12983540001	400473178	SGT	TAG6	995	70471	1,041.40	TAG6	SGSS2/SCD2/SGDS2
37	12983543001	400473167	SGT	TI4	986	70402	2,443.06	TI4	SDS/LGSS
37	12983544001	400473159	SGT	TAG6	981	70477	1,645.85	TAG6	SGSS2/SCD2/SGDS2
37	12983545001	400473135	SGT	TAG6	960	70454	975.58	TAG6	SGSS2/SCD2/SGDS2
37	12983546001	400473132	SG2		956	70471	1,306.97	SG2	SGSS2/SCD2/SGDS2
37	12983548001	400473128	SC2		952	70470	2,612.96	SC2	SGSS2/SCD2/SGDS2
37	12983553001	400526717	SGT	TI4	940	70474	3,553.45	TI4	SDS/LGSS
37	12983554002	400510507	SGT	TI4	926	70495	813.91	TI4	SDS/LGSS
37	12983554002	500146350	SGT	TI4	926	70495	813.91	TI4	SDS/LGSS
37	12983556001	400475899	SGT	TIB	906	70456	8,689.61	TIB	SDS/LGSS
37	12983557001	400473076	SGT	TI4	908	70404	0.00	TI4	SDS/LGSS
37	12983558001	400473075	SGT	TI4	903	70424	3,639.69	TI4	SDS/LGSS
37	12983559001	400473069	SGT	TI4	899	70406	2,168.14	TI4	SDS/LGSS
37	12983561002	400473046	SGT	TIB	882	70478	2,570.17	TIB	SDS/LGSS
37	12983562001	400473038	SGT	TI4	875	70470	47,220.54	TI4	SDS/LGSS
37	12983563001	400473021	SGT	TIB	4551	70422	4,003.27	TIB	SDS/LGSS
37	12983571001	400472962	SGT	TAG2	819	70495	3,332.98	TAG2	SGSS2/SCD2/SGDS2
37	12983572001	400472961	SGT	TAG2	3243	70471	1,574.91	TAG2	SGSS2/SCD2/SGDS2
37	12983576001	400472937	SGT	TAG6	803	190613	1,986.61	TAG6	SGSS2/SCD2/SGDS2
37	12983577003	400472935	SGT	TIB	801	70495	60,183.80	TIB	SDS/LGSS
37	12983587001	400472914	SGT	TAG6	786	70454	851.16	TAG6	SGSS2/SCD2/SGDS2
37	12983589001	400472900	SGT	TAG6	772	70478	1,636.96	TAG6	SGSS2/SCD2/SGDS2
37	12983591001	400472897	SGS		4602	70478	1,645.78	SGS	SGSS1/SCD1/SGDS1
37	12983595001	400487894	SGT	TIB	3343	70470	1,889.13	TIB	SDS/LGSS
37	12983596001	400472878	SGT	841	757	190613	1,747.62	841	SGSS2/SCD2/SGDS2
37	12983597001	400472873	SGT	TAG6	752	70471	1,622.22	TAG6	SGSS2/SCD2/SGDS2
37	12983602002	400504762	SGT	TAG6	721	70495	428.90	TAG6	SGSS2/SCD2/SGDS2
37	12983603001	400472840	SGT	TIB	4550	70405	2,829.72	TIB	SDS/LGSS
37	12983604001	400472837	SGT	TAG6	716	70479	1,537.45	TAG6	SGSS2/SCD2/SGDS2
37	12983606002	400472820	SGT	TI4	702	70495	23,896.62	TI4	SDS/LGSS
37	12983611001	400503381	SGT	TI8	14705	70403	8,425.15	TI8	LDS/LGSS
37	12983623002	400473179	SGT	TAG6	996	310911	1,721.36	TAG6	SGSS2/SCD2/SGDS2
37	12983623002	500146278	SGT	TAG6	996	310911	1,721.36	TAG6	SGSS2/SCD2/SGDS2
37	12983626001	400473108	SGT	TAG6	933	310958	0.00	TAG6	SGSS2/SCD2/SGDS2
37	12983627001	400473107	SGT	TAG6	932	310956	498.89	TAG6	SGSS2/SCD2/SGDS2
37	12983628002	400473106	SGT	TI4	931	310918	0.00	TI4	SDS/LGSS
37	12983630001	400526948	SG2		4420	333908	29,515.75	SG2	SGSS2/SCD2/SGDS2
37	12983634001	400526518	SGT	TIB	291	1252820	5,614.75	TIB	SDS/LGSS
37	12983644001	400512422	SGT	TIB	1155	1252896	10,801.61	TIB	SDS/LGSS
37	12983645004	400492992	SGT	802	1121	1252804	14,862.32	802	MDS/NSS
37	12983645004	500142415	SGT	802	1121	1252804	14,862.32	802	MDS/NSS
37	12983645005	500147711	SGT	801	1249	1252807	14,992.56	801	SDS/LGSS
37	12983646002	400481256	SGT	859	1114	1252804	14,725.43	859	LDS/LGSS
37	12983651001	400472750	SGT	TIF	1241	1252829	12,773.89	TIF	LDS/LGSS
37	12983654002	400472745	SGT	TAG2	1236	1252896	6,610.88	TAG2	SGSS2/SCD2/SGDS2
37	12983655001	400472742	SGT	TIB	14101	1252807	5,736.00	TIB	SDS/LGSS
37	12983663001	400505567	SGT	TAG2	14764	1252821	3,352.37	TAG2	SGSS2/SCD2/SGDS2

37	12983681002	400472637	SGT	TIB	1141	1252803	18,010.19	TIB	SDS/LGSS
37	12983691002	400478146	SG2		1096	1252829	3,176.25	SG2	SGSS2/SCD2/SGDS2
37	12983693004	400506899	SGT	TI4	14766	1252821	4,992.09	TI4	SDS/LGSS
37	12983702005	400526549	SGT	TIB	48460	1252829	16,540.14	TIB	SDS/LGSS
37	12983704003	400526520	SG2		48852	591705	5,420.01	SG2	SGSS2/SCD2/SGDS2
37	12983720001	400496395	SGT	TIB	14548	190622	3,199.77	TIB	SDS/LGSS
37	12983722004	400473084	SGT	878	4008	190661	45,282.63	878	MDS/NSS
37	12983723002	400473025	LG1		865	190628	30,343.67	LG1	SDS/LGSS
37	12983778004	400526322	SGT	TI4	44903	30287	30,605.62	TI4	SDS/LGSS
37	12983801005	500151204	SGT	846	1225	30205	18,391.89	846	LDS/LGSS
37	12983801005	800800501	SGT	846	1227	30257	1,166.44	846	LDS/LGSS
37	12983811001	400472633	SGT	TIB	1138	30298	47,133.30	TIB	SDS/LGSS
37	12983816001	400497901	SGT	847	14538	30298	9,865.70	847	SDS/LGSS
37	12983818001	400472771	SGT	TAG6	3402	30205	989.28	TAG6	SGSS2/SCD2/SGDS2
37	12983820001	400472767	SG2		1068	30284	3,178.21	SG2	SGSS2/SCD2/SGDS2
37	12983822001	400472761	SGT	TAG6	1252	30244	1,277.77	TAG6	SGSS2/SCD2/SGDS2
37	12983826001	400472724	LG2		1215	30284	5,613.85	LG2	SDS/LGSS
37	12983826003	500263862	SG2		46403	30284	8,986.03	SG2	SGSS2/SCD2/SGDS2
37	12983829001	400472706	SG2		1204	30287	1,520.91	SG2	SGSS2/SCD2/SGDS2
37	12983833001	400472696	SG2		1195	30298	1,527.24	SG2	SGSS2/SCD2/SGDS2
37	12983835001	400472693	SGT	TAG6	1192	30289	1,740.31	TAG6	SGSS2/SCD2/SGDS2
37	12983836001	400472692	SGT	TAG6	1191	30287	14,604.29	TAG6	SGSS2/SCD2/SGDS2
37	12983838001	400472689	SGT	TAG2	3319	30286	2,574.51	TAG2	SGSS2/SCD2/SGDS2
37	12983839001	400472688	SGT	TIF	1187	30224	7,032.39	TIF	LDS/LGSS
37	12983840001	800800394	SGT	TAG6	1177	30298	1,351.98	TAG6	SGSS2/SCD2/SGDS2
37	12983844001	400472669	SG2		1171	30268	1,107.63	SG2	SGSS2/SCD2/SGDS2
37	12983845001	400472667	SGT	TIB	3320	30205	1,421.80	TIB	SDS/LGSS
37	12983846001	400472666	SGT	TI4	1169	30298	2,420.80	TI4	SDS/LGSS
37	12983847001	400472665	SGT	TAG6	1168	30298	1,735.12	TAG6	SGSS2/SCD2/SGDS2
37	12983848001	400472659	SG2		1163	30298	1,458.03	SG2	SGSS2/SCD2/SGDS2
37	12983852004	400472629	SGT	TIB	1135	30298	365.16	TIB	SDS/LGSS
37	12983855001	400472621	SGT	TAG6	3401	30224	1,484.68	TAG6	SGSS2/SCD2/SGDS2
37	12983856002	400472620	SGT	TAG6	1125	30262	3,096.42	TAG6	SGSS2/SCD2/SGDS2
37	12983862002	400472577	SGT	TAG2	4353	30298	10,816.55	TAG2	SGSS2/SCD2/SGDS2
37	12983863001	400472566	SGT	TIB	1082	30240	7,768.34	TIB	SDS/LGSS
37	12983864001	400472564	SGT	TAG6	4530	30298	1,442.57	TAG6	SGSS2/SCD2/SGDS2
37	12983867001	400490005	SGT	TI4	14441	30298	3,399.12	TI4	SDS/LGSS
37	12983868001	800800388	LG2		1073	30236	1,054.99	LG2	SDS/LGSS
37	12983871001	400472535	SGT	TAG6	1049	30298	16,882.20	TAG6	SGSS2/SCD2/SGDS2
37	12983873001	400472530	SGT	TI4	4287	30287	1,952.86	TI4	SDS/LGSS
37	12983875003	501090417	SGT	TIB	49141	30287	73,329.36	TIB	SDS/LGSS
37	12983877001	400472526	SGT	TIB	1041	30224	26,320.69	TIB	SDS/LGSS
37	12983880001	400472523	SGT	TI4	1038	30205	2,362.23	TI4	SDS/LGSS
37	12983881001	400472519	SGT	TAG6	1034	30240	3,086.55	TAG6	SGSS2/SCD2/SGDS2
37	12983883004	400510094	SGT	TIB	44023	30244	4,419.14	TIB	SDS/LGSS
37	12983883004	500149722	SGT	TIB	45235	30244	3,074.68	TIB	SDS/LGSS
37	12983883004	500310911	SGT	TIB	46787	30244	3,074.68	TIB	SDS/LGSS
37	12983883004	800800386	SGT	TIB	45235	30244	3,074.68	TIB	SDS/LGSS
37	12983884001	400503379	SGT	TIB	14503	30244	1,114.71	TIB	SDS/LGSS
37	12983885004	400472514	SGT	TI4	48589	30295	0.00	TI4	SDS/LGSS
37	12983886001	400472513	SGT	TAG2	4687	30295	2,325.82	TAG2	SGSS2/SCD2/SGDS2
37	12983915002	400472655	SGT	838	1159	30216	17,524.35	838	SDS/LGSS
37	12983919001	400472609	SC2		1116	30243	1,108.68	SC2	SGSS2/SCD2/SGDS2
37	12983922001	400472593	SGT	TAG6	1103	30243	3,946.85	TAG6	SGSS2/SCD2/SGDS2
37	12983923001	400477150	SGT	TAG6	1091	30276	1,170.43	TAG6	SGSS2/SCD2/SGDS2
37	12983930001	400505076	SGT	TI8	14546	30225	6,674.65	TI8	LDS/LGSS
37	12983934001	400484301	SGT	TIF	937	70452	19,291.15	TIF	LDS/LGSS
37	12983936001	400473091	SGT	TI8	916	30225	24,051.98	TI8	LDS/LGSS
37	12983938001	400473088	SGT	TIF	913	30225	27,714.20	TIF	LDS/LGSS
37	12983939001	400473057	SGT	TIF	887	30225	6,398.34	TIF	LDS/LGSS
37	12983940001	400512126	SG4		14470	30272	2,266.48	SG4	SGSS2/SCD2/SGDS2
37	12983942001	400526836	SGT	TIB	45213	30225	10,318.32	TIB	SDS/LGSS

37	12983946001	400493917	SGT	819	14046	70452	114,066.43	819	LDS/LGSS
37	12983954001	400518548	SGT	TAG2	1016	30280	1,793.76	TAG2	SGSS2/SCD2/SGDS2
37	12983968001	400473146	SGT	TAG6	971	30280	1,505.38	TAG6	SGSS2/SCD2/SGDS2
37	12983969001	400473144	SGT	TI8	4078	30280	8,666.74	TI8	LDS/LGSS
37	12983971001	400473142	SGT	TIB	968	30263	3,123.75	TIB	SDS/LGSS
37	12983976001	400473125	SGT	TAG6	949	30231	2,662.32	TAG6	SGSS2/SCD2/SGDS2
37	12983979001	400473122	SG2		946	30220	2,913.58	SG2	SGSS2/SCD2/SGDS2
37	12983982001	400473103	SGT	TI4	929	30272	2,434.70	TI4	SDS/LGSS
37	12983988002	400473027	SG2		4097	30272	1,504.40	SG2	SGSS2/SCD2/SGDS2
37	12983988002	400498427	SG2		4285	30272	0.00	SG2	SGSS2/SCD2/SGDS2
37	12983989001	400473067	SGT	TAG6	897	30255	1,605.63	TAG6	SGSS2/SCD2/SGDS2
37	12983993001	400473045	SGT	TI4	881	30235	2,566.18	TI4	SDS/LGSS
37	12983994003	400473044	SGT	TI4	880	30235	2,280.48	TI4	SDS/LGSS
37	12984010001	400472957	SGT	TI4	815	30265	1,642.85	TI4	SDS/LGSS
37	12984012001	400526772	SGT	TAG6	810	30272	2,525.24	TAG6	SGSS2/SCD2/SGDS2
37	12984017001	400481787	SGT2	TAG2	4558	30223	1,655.15	TAG2	SGSS2/SCD2/SGDS2
37	12984018001	400481786	SGT	TI4	4603	30223	1,991.88	TI4	SDS/LGSS
37	12984019001	400481785	SGT	TAG2	4629	30223	1,378.79	TAG2	SGSS2/SCD2/SGDS2
37	12984034007	400481784	SGT	TI4	4053	30223	1,655.15	TI4	SDS/LGSS
37	12984034007	500265247	SGT	TI4	4053	30223	1,655.15	TI4	SDS/LGSS
37	12984034007	800800374	SGT	TI4	4054	30223	1,655.15	TI4	SDS/LGSS
37	12984034007	800800375	SGT	TI4	4066	30223	1,178.76	TI4	SDS/LGSS
37	12984034007	800800376	SGT	TI4	4079	30223	1,655.15	TI4	SDS/LGSS
37	12984034007	800800377	SGT	TI4	4435	30223	1,655.15	TI4	SDS/LGSS
37	12984043001	400517683	LG2		44475	30221	3,279.27	LG2	SDS/LGSS
37	12984046001	400472830	SGT	TAG6	3256	30252	1,191.30	TAG6	SGSS2/SCD2/SGDS2
37	12984053001	400472803	SGT	TI4	688	30231	2,898.82	TI4	SDS/LGSS
37	12984054001	400472802	SGT	TAG6	687	30251	1,838.17	TAG6	SGSS2/SCD2/SGDS2
37	12984056001	400472800	SGT	TAG2	685	30252	5,185.01	TAG2	SGSS2/SCD2/SGDS2
37	12984057001	400472794	SG2		14003	70452	2,817.69	SG2	SGSS2/SCD2/SGDS2
37	12984060001	400472789	SGT	TI4	675	30231	2,006.04	TI4	SDS/LGSS
37	12984062001	400507544	SGT	TIB	14759	30201	1,771.72	TIB	SDS/LGSS
37	12984063001	400519504	SG2		1601	30272	1,526.77	SG2	SGSS2/SCD2/SGDS2
37	12984091001	400472776	SGT	TIB	3296	1252806	2,490.72	TIB	SDS/LGSS
37	12984092001	400472775	SGT	TIB	296	1252825	4,334.99	TIB	SDS/LGSS
37	12984098001	400526718	SGT	TM2	45180	1252822	3,030.87	TM2	MDS/NSS
37	12984098003	400490002	SGT	TIF-EFACT	14453	10154	2,599.58	TIF-EFACT	LDS/LGSS
37	12984110001	400472744	SGT	TI4	1235	1252806	2,570.28	TI4	SDS/LGSS
37	12984111005	400164887	LG1		47080	1252824	4,447.68	LG1	SDS/LGSS
37	12984111005	400164886	LG1		47081	1252824	4,447.68	LG1	SDS/LGSS
37	12984111005	400164888	LG1		47082	1252824	4,447.68	LG1	SDS/LGSS
37	12984111005	400472738	LG1		1229	1252824	4,582.60	LG1	SDS/LGSS
37	12984119001	400494178	SG2		1174	1252823	27,949.22	SG2	SGSS2/SCD2/SGDS2
37	12984122008	400472639	SGT	TIB	48825	1252822	23,753.50	TIB	SDS/LGSS
37	12984125001	400472585	SGT	TIB	4502	1252819	3,398.13	TIB	SDS/LGSS
37	12984126001	400520878	SG2		44418	1252822	1,479.44	SG2	SGSS2/SCD2/SGDS2
37	12984129002	400472553	SGT	TIB	1070	1252807	7,184.54	TIB	SDS/LGSS
37	12984131002	500789128	SGT	TIB	48657	1252822	6,756.22	TIB	SDS/LGSS
37	12984143001	400501976	SGT	TIB	14605	1252822	5,254.56	TIB	SDS/LGSS
37	12984148001	400518885	SGT	874	44408	30241	14,184.28	874	SDS/LGSS
37	12984150004	400475667	SGT	875	3237	273860	7,044.37	875	LDS/LGSS
37	12984150004	500149539	SGT	875	3237	273860	7,044.37	875	LDS/LGSS
37	12984150004	501030792	SGT	875	49154	273860	170.68	875	LDS/LGSS
37	12984150004	800800371	SGT	875	4385	273804	13,642.89	875	LDS/LGSS
37	12984150005	400498737	SG2		14439	273806	5,140.01	SG2	SGSS2/SCD2/SGDS2
37	12984150007	501179703	SG2		49333	273860	170.68	SG2	SGSS2/SCD2/SGDS2
37	12984151020	400475666	SGT	TIF	1565	273860	294.12	TIF	LDS/LGSS
37	12984151020	400514859	SGT	TIF	48789	273860	170.68	TIF	LDS/LGSS
37	12984151020	400514976	SGT	TIF	48788	273860	170.68	TIF	LDS/LGSS
37	12984151020	400526997	SGT	TIF	45666	273860	170.68	TIF	LDS/LGSS
37	12984151020	500008214	SGT	TIF	48790	273860	170.68	TIF	LDS/LGSS
37	12984151020	500130476	SGT	TIF	45665	273860	170.68	TIF	LDS/LGSS

37	12984151020	500130460	SGT	TIF	45732	273804	327.89	TIF	LDS/LGSS
37	12984151020	500130474	SGT	TIF	48526	273860	170.68	TIF	LDS/LGSS
37	12984151020	500130459	SGT	TIF	48889	273860	170.68	TIF	LDS/LGSS
37	12984151020	500136322	SGT	TIF	45731	273804	327.89	TIF	LDS/LGSS
37	12984151020	500150517	SGT	TIF	45908	273860	170.68	TIF	LDS/LGSS
37	12984151020	500162068	SGT	TIF	45949	273860	170.68	TIF	LDS/LGSS
37	12984151020	500198356	SGT	TIF	46017	273804	7,337.20	TIF	LDS/LGSS
37	12984151020	500198359	SGT	TIF	46018	273804	5,413.76	TIF	LDS/LGSS
37	12984151020	500208315	SGT	TIF	46494	273804	327.89	TIF	LDS/LGSS
37	12984151020	500555580	SGT	TIF	48444	273860	170.68	TIF	LDS/LGSS
37	12984151020	500558423	SGT	TIF	48887	273860	170.68	TIF	LDS/LGSS
37	12984151020	500612327	SGT	TIF	48438	273804	327.89	TIF	LDS/LGSS
37	12984151020	500625771	SGT	TIF	48958	273860	612.22	TIF	LDS/LGSS
37	12984151020	500659013	SGT	TIF	48965	273860	170.68	TIF	LDS/LGSS
37	12984151020	500667297	SGT	TIF	48439	273804	327.89	TIF	LDS/LGSS
37	12984151020	500667298	SGT	TIF	48440	273860	2,124.04	TIF	LDS/LGSS
37	12984151020	500692603	SGT	TIF	48625	273860	170.68	TIF	LDS/LGSS
37	12984151020	500707423	SGT	TIF	48970	273804	327.89	TIF	LDS/LGSS
37	12984151020	500709556	SGT	TIF	48543	273860	170.68	TIF	LDS/LGSS
37	12984151020	500716291	SGT	TIF	48471	273860	170.68	TIF	LDS/LGSS
37	12984151020	500806647	SGT	TIF	48678	273860	170.68	TIF	LDS/LGSS
37	12984151020	500856054	SGT	TIF	48736	273804	327.89	TIF	LDS/LGSS
37	12984151020	500875536	SGT	TIF	48749	273804	327.89	TIF	LDS/LGSS
37	12984151020	500918034	SGT	TIF	48624	273860	170.68	TIF	LDS/LGSS
37	12984151020	500949336	SGT	TIF	48808	273860	170.68	TIF	LDS/LGSS
37	12984151020	500949337	SGT	TIF	48809	273860	170.68	TIF	LDS/LGSS
37	12984151020	800800356	SGT	TIF	4371	273860	170.68	TIF	LDS/LGSS
37	12984151020	800800357	SGT	TIF	4373	273860	170.68	TIF	LDS/LGSS
37	12984151020	800800358	SGT	TIF	4374	273860	2,126.16	TIF	LDS/LGSS
37	12984151020	800800359	SGT	TIF	4375	273860	1,899.64	TIF	LDS/LGSS
37	12984151020	800800360	SGT	TIF	4376	273860	170.68	TIF	LDS/LGSS
37	12984151020	800800361	SGT	TIF	4377	273860	825.56	TIF	LDS/LGSS
37	12984151020	800800362	SGT	TIF	4378	273860	3,312.21	TIF	LDS/LGSS
37	12984151020	800800364	SGT	TIF	4380	273860	550.88	TIF	LDS/LGSS
37	12984151020	800800365	SGT	TIF	4381	273804	327.89	TIF	LDS/LGSS
37	12984151020	800800366	SGT	TIF	4382	273860	170.68	TIF	LDS/LGSS
37	12984151020	800800367	SGT	TIF	4383	273860	2,870.04	TIF	LDS/LGSS
37	12984151020	800800369	SGT	TIF	14823	273860	(237.74)	TIF	LDS/LGSS
37	12984151020	800800370	SGT	TIF	45243	273804	327.89	TIF	LDS/LGSS
37	12984151020	800800354	SGT	TIF	49234	273860	170.68	TIF	LDS/LGSS
37	12984151057	500972343	SG2		48807	273804	327.89	SG2	SGSS2/SCD2/SGDS2
37	12984156001	400498964	SGT	TI8	14387	273821	5,123.96	TI8	LDS/LGSS
37	12984156003	501081996	SGT	TIB	49125	273821	12,542.30	TIB	SDS/LGSS
37	12984173001	400472492	SG2		1561	273860	2,182.70	SG2	SGSS2/SCD2/SGDS2
37	12984182002	400472462	SGT	TIB	4457	273860	10,409.20	TIB	SDS/LGSS
37	12984188002	400472449	SGT	TI8	4450	273804	5,656.93	TI8	LDS/LGSS
37	12984190001	400472445	SGT	TI4	4241	273851	1,739.73	TI4	SDS/LGSS
37	12984211001	400479603	SG2		4238	273851	2,043.76	SG2	SGSS2/SCD2/SGDS2
37	12984212001	400526754	SGT	TAG5	45237	273802	8,126.09	TAG5	SGSS1/SCD1/SGDS1
37	12984213001	400526784	SGT	TIB	45047	273821	10,484.67	TIB	SDS/LGSS
37	12984215001	400526343	SGT	TI4	44949	273804	327.89	TI4	SDS/LGSS
37	12984218002	400472435	SGT	TIB	1493	551552	0.00	TIB	SDS/LGSS
37	12984219005	400472431	LG2		294	551501	0.00	LG2	SDS/LGSS
37	12984219005	500165435	LG2		294	551501	0.00	LG2	SDS/LGSS
37	12984221002	400472381	SGT	TIB	1490	551501	5,370.70	TIB	SDS/LGSS
37	12984221004	501123144	SGT	TIF	49284	551501	2,638.10	TIF	LDS/LGSS
37	12984228001	400472417	SG2		1515	551504	4,265.74	SG2	SGSS2/SCD2/SGDS2
37	12984229004	400472415	SGT	TAG6	1519	551511	882.28	TAG6	SGSS2/SCD2/SGDS2
37	12984229004	800800337	SGT	TAG6	45675	551554	0.00	TAG6	SGSS2/SCD2/SGDS2
37	12984230001	400472414	SGT	TI4	1513	551554	4,102.66	TI4	SDS/LGSS
37	12984232001	400472408	NSI		1511	551511	644.76	NSI	MDS/NSS
37	12984233004	400472404	SGT	TIB	1508	551553	1,128.54	TIB	SDS/LGSS

37	12984233004	800800336	SGT	TIB	4507	551553	9,209.77	TIB	SDS/LGSS
37	12984235003	400503659	SGT	TI4	14732	551511	4,687.22	TI4	SDS/LGSS
37	12984235003	500232234	SGT	TI4	48041	551511	644.76	TI4	SDS/LGSS
37	12984242001	400494798	SGT	TI8	14599	10160	5,052.78	TI8	LDS/LGSS
37	12984245001	400514975	SGT	TAG6	44087	10153	2,947.61	TAG6	SGSS2/SCD2/SGDS2
37	12984246003	500416284	SGT	TAG6	47469	1333025	20,771.85	TAG6	SGSS2/SCD2/SGDS2
37	12984247004	400472434	SGT	TIF	297	10109	12,792.40	TIF	LDS/LGSS
37	12984247004	400472433	SGT	TIF	4339	10109	10,711.17	TIF	LDS/LGSS
37	12984247004	800800335	SGT	TIF	14446	10109	10,829.50	TIF	LDS/LGSS
37	12984250003	400507411	SGT	TI8	3215	10154	5,115.03	TI8	LDS/LGSS
37	12984250003	400507413	SGT	TI8	3215	10154	5,115.03	TI8	LDS/LGSS
37	12984251001	400507412	SGT	TI8	1510	10120	18,723.94	TI8	LDS/LGSS
37	12984252001	400472401	SGT	TAG6	1506	10160	2,716.17	TAG6	SGSS2/SCD2/SGDS2
37	12984255005	400472391	SGT	TAG6	4293	10158	4,096.56	TAG6	SGSS2/SCD2/SGDS2
37	12984257002	400472388	SGT	TIF	3334	10120	28.10	TIF	LDS/LGSS
37	12984257002	500149512	SGT	TIF	1496	10120	11,870.14	TIF	LDS/LGSS
37	12984261001	400472371	SGT	TIF	3384	10114	5,204.65	TIF	LDS/LGSS
37	12984262001	400517972	SGT	TIB	44406	10160	3,203.39	TIB	SDS/LGSS
37	12984264001	400472364	SGT	TIB	1477	10117	2,125.64	TIB	SDS/LGSS
37	12984269001	400498767	SGT	TI8	14635	10119	7,870.20	TI8	LDS/LGSS
37	12984270006	400498095	SGT	TIB	14526	1333072	4,269.98	TIB	SDS/LGSS
37	12984271002	400490462	SGT	TIB	14386	10156	7,754.25	TIB	SDS/LGSS
37	12984273001	400522508	SGT	TIB	44530	10105	4,338.27	TIB	SDS/LGSS
37	12984275001	400472429	SGT	TIB	1523	10157	13,872.58	TIB	SDS/LGSS
37	12984276001	400511898	SGT	TIB	44051	10157	2,268.56	TIB	SDS/LGSS
37	12984278001	400511635	SG2		1517	10157	1,581.31	SG2	SGSS2/SCD2/SGDS2
37	12984279001	400472413	SG2		3297	10104	1,202.11	SG2	SGSS2/SCD2/SGDS2
37	12984281001	400472403	SG2		1507	10157	5,011.48	SG2	SGSS2/SCD2/SGDS2
37	12984282002	400472402	SGT	TAG2	3499	10119	1,353.99	TAG2	SGSS2/SCD2/SGDS2
37	12984283001	400472399	SGT	TIB	3187	10158	2,708.97	TIB	SDS/LGSS
37	12984291001	400472378	SGT	TI4	1486	10157	3,434.35	TI4	SDS/LGSS
37	12984293002	400472376	SGT	821	285	10109	24,644.73	821	MDS/NSS
37	12984293003	500925519	SGT	858	48785	10109	16,768.97	858	SDS/LGSS
37	12984294001	400472374	SGT	TI4	4348	10109	1,212.01	TI4	SDS/LGSS
37	12984296001	400472372	SGT	TAG6	1483	10104	2,598.74	TAG6	SGSS2/SCD2/SGDS2
37	12984299002	400472366	SGT	TI8	1479	10157	4,617.06	TI8	LDS/LGSS
37	12984299002	500220827	SGT	TI8	46090	10157	(2,477.86)	TI8	LDS/LGSS
37	12984318001	400051028	SGT	TI8	48031	1333063	717.31	TI8	LDS/LGSS
37	12984318001	400472328	SGT	TI8	3515	1333063	4,627.20	TI8	LDS/LGSS
37	12984318001	400472327	SGT	TI8	3636	1333063	4,224.76	TI8	LDS/LGSS
37	12984318001	400494708	SGT	TI8	48033	1333063	717.31	TI8	LDS/LGSS
37	12984318001	400505362	SGT	TI8	48677	1333063	717.31	TI8	LDS/LGSS
37	12984318001	400507194	SGT	TI8	46075	1333063	717.31	TI8	LDS/LGSS
37	12984318001	400514810	SGT	TI8	48034	1333063	717.31	TI8	LDS/LGSS
37	12984318001	500005922	SGT	TI8	48032	1333063	717.31	TI8	LDS/LGSS
37	12984318001	500119649	SGT	TI8	45688	1333063	3,470.16	TI8	LDS/LGSS
37	12984321001	400472320	SGT	TIB	3543	1333025	2,893.81	TIB	SDS/LGSS
37	12984323001	400472318	SGT	TIF	3632	1333025	32,431.00	TIF	LDS/LGSS
37	12984324001	400472317	SG2		3542	1333025	1,613.38	SG2	SGSS2/SCD2/SGDS2
37	12984325001	400472316	SGT	TIG	3631	1333025	13,299.28	TIG	LDS/LGSS
37	12984327001	400472263	SGT	TI4	4536	1333025	1,730.75	TI4	SDS/LGSS
37	12984329001	400526741	SGT	TIF	45205	1333025	29,485.39	TIF	LDS/LGSS
37	12984343004	400490919	SGT	TIG	14417	1333063	18,898.59	TIG	LDS/LGSS
37	12984343004	500023117	SGT	TIG	48880	1333063	717.31	TIG	LDS/LGSS
37	12984343004	500535850	SGT	TIG	48881	1333063	717.31	TIG	LDS/LGSS
37	12984346001	400526951	SGT	TIB	44971	1333025	3,924.43	TIB	SDS/LGSS
37	12984351001	400472299	SGT	TIB	3527	1333025	5,492.43	TIB	SDS/LGSS
37	12984355001	400472293	LG2		3521	10103	1,321.13	LG2	SDS/LGSS
37	12984357001	400472287	SGT	TIF	3625	1333063	194.35	TIF	LDS/LGSS
37	12984366001	400472272	SGT	TIB	3506	1333063	5,646.08	TIB	SDS/LGSS
37	12984368001	400472269	SGT	TIB	3504	1333063	3,476.30	TIB	SDS/LGSS
37	12984378001	400496892	SGT	TAG6	14565	1333017	3,062.04	TAG6	SGSS2/SCD2/SGDS2

37	12984380001	400494812	SGT	TIB	14520	1333095	3,163.10	TIB	SDS/LGSS
37	12984382001	400493516	SGT	TIB	14532	1333017	6,438.24	TIB	SDS/LGSS
37	12984392002	400472214	SGT	TIB	3569	1333074	3,825.82	TIB	SDS/LGSS
37	12984392002	400472233	SGT	TIB	3649	1333074	10,068.11	TIB	SDS/LGSS
37	12984392002	800800313	SGT	TIB	3648	1333074	3,347.55	TIB	SDS/LGSS
37	12984417001	400472186	SGT	TAG2	4515	1333095	1,971.18	TAG2	SGSS2/SCD2/SGDS2
37	12984427001	400472128	SGT	TIB	3956	1333029	301.15	TIB	SDS/LGSS
37	12984428001	400493347	SGT	TIB	3950	1333032	4,743.56	TIB	SDS/LGSS
37	12984433001	400474737	SGT	TIB	14041	1333014	6,272.31	TIB	SDS/LGSS
37	12984436001	400516474	SGT	TIB	3863	1333029	13,199.30	TIB	SDS/LGSS
37	12984438005	400517692	SGT	TI8	14678	1333029	8,218.52	TI8	LDS/LGSS
37	12984438005	400526273	SGT	TI8	44876	1333029	5,910.79	TI8	LDS/LGSS
37	12984438005	800800325	SGT	TI8	3916	1333029	6,020.27	TI8	LDS/LGSS
37	12984438005	800800326	SGT	TI8	3917	1333029	7,803.46	TI8	LDS/LGSS
37	12984440001	400472099	SGT	TIB	3909	1333032	1,833.70	TIB	SDS/LGSS
37	12984442001	400472096	SGT	TIG	14693	1333032	6,788.34	TIG	LDS/LGSS
37	12984443001	400472090	SGT	TIB	3901	1333095	4,730.90	TIB	SDS/LGSS
37	12984445003	400472088	SG4		3896	1333032	4,617.68	SG4	SGSS2/SCD2/SGDS2
37	12984445004	400472089	SG4		3897	1333032	4,749.76	SG4	SGSS2/SCD2/SGDS2
37	12984447001	400526359	SGT	TI8	3894	1333032	18.07	TI8	LDS/LGSS
37	12984448001	400472085	SGT	TI8	3893	1333027	6,582.03	TI8	LDS/LGSS
37	12984450007	500793520	SGT	TIF	48680	1333027	19,139.64	TIF	LDS/LGSS
37	12984453004	400505585	SGT	TI4	3881	1333029	15,019.06	TI4	SDS/LGSS
37	12984460001	400472065	SGT	TIB	3866	1333017	1,150.36	TIB	SDS/LGSS
37	12984462001	400472061	SGT	TIB	3860	1333027	8,853.30	TIB	SDS/LGSS
37	12984467001	400472046	SGT	TIB	4248	1333017	3,361.03	TIB	SDS/LGSS
37	12984472001	400472020	SGT	TAG6	3803	1333027	5,226.08	TAG6	SGSS2/SCD2/SGDS2
37	12984475001	400472016	SGT	TIB	3799	1333027	77.96	TIB	SDS/LGSS
37	12984476001	400472014	SGT	TIB	3795	1333027	8,044.15	TIB	SDS/LGSS
37	12984477004	400472012	SG2		3792	1333027	600.79	SG2	SGSS2/SCD2/SGDS2
37	12984477004	800800315	SG2		3793	1333027	14.60	SG2	SGSS2/SCD2/SGDS2
37	12984484006	400467049	SGT	TIB	47453	1333083	6.06	TIB	SDS/LGSS
37	12984484006	400471998	SGT	TIB	14566	1333083	16,591.26	TIB	SDS/LGSS
37	12984484006	500151812	SGT	TIB	47456	1333083	6.06	TIB	SDS/LGSS
37	12984487001	400471977	SGT	TI8	4335	1333077	5,989.39	TI8	LDS/LGSS
37	12984490001	400526586	SGT	TIF	4037	1333079	67,184.66	TIF	LDS/LGSS
37	12984493001	400471935	SGT	TAG2	4516	1333095	1,610.31	TAG2	SGSS2/SCD2/SGDS2
37	12984497001	400471892	SGT	TIB	4173	1333095	4,124.51	TIB	SDS/LGSS
37	12984501001	400471867	SGT	TIF	4155	1333095	11,536.99	TIF	LDS/LGSS
37	12984504001	400471831	SG2		4141	1333029	963.30	SG2	SGSS2/SCD2/SGDS2
37	12984505001	400471820	SGT	TAG2	4517	1333095	1,487.51	TAG2	SGSS2/SCD2/SGDS2
37	12984507001	400471805	SGT	TIB	4556	1333014	9,445.81	TIB	SDS/LGSS
37	12984517001	400526829	SG2		4111	1333029	197.95	SG2	SGSS2/SCD2/SGDS2
37	12984524001	400507001	SGT	TIB	14552	1333017	4,496.64	TIB	SDS/LGSS
37	12984528001	400507730	SGT	TIF	3971	1333029	18,621.19	TIF	LDS/LGSS
37	12984529002	400495160	SGT	831	293	290806	0.00	831	MDS/NSS
37	12984533001	400494422	SGT	TI8	14521	1333027	3,327.47	TI8	LDS/LGSS
37	12984534001	400491763	SGT	TI4	14383	1333029	2,097.56	TI4	SDS/LGSS
37	12984538001	400496374	SGT	TIB	14554	1333095	5,547.66	TIB	SDS/LGSS
37	12984541001	400472240	SGT	TIB	4443	1333074	2,583.06	TIB	SDS/LGSS
37	12984542001	400499351	SG2		14534	1333029	3,158.50	SG2	SGSS2/SCD2/SGDS2
37	12984549001	400496547	SGT	TIB	14438	1333095	7,445.55	TIB	SDS/LGSS
37	12984561001	400472176	SGT	TIB	3969	1333095	8,717.36	TIB	SDS/LGSS
37	12984569008	400472068	SGT	TIF	3869	1333029	19,391.81	TIF	LDS/LGSS
37	12984569008	400492606	SGT	TIF	47118	1333029	10,688.18	TIF	LDS/LGSS
37	12984569008	400505836	SGT	TIF	47356	1333029	7,803.46	TIF	LDS/LGSS
37	12984569008	400516746	SGT	TIF	47028	1333029	7,803.46	TIF	LDS/LGSS
37	12984576002	400472052	SGT	TIB	3847	1333032	7,490.23	TIB	SDS/LGSS
37	12984584004	800800311	SGT	TIB	14595	1333029	3,083.07	TIB	SDS/LGSS
37	12984585004	400472035	SGT	TIB	3824	1333029	12.68	TIB	SDS/LGSS
37	12984585004	800800310	SGT	TIB	3825	1333029	2,269.87	TIB	SDS/LGSS
37	12984588001	400471996	SGT	TI4	3703	1333027	1,553.45	TI4	SDS/LGSS

37	12984592001	400471991	SGT	TI8	3698	1333069	12,248.59	TI8	LDS/LGSS
37	12984596001	400471986	SGT	TAG6	3754	1333017	1,646.10	TAG6	SGSS2/SCD2/SGDS2
37	12984597001	400471985	SGT	TAG6	3753	1333005	5,014.00	TAG6	SGSS2/SCD2/SGDS2
37	12984598001	400471984	SGT	TIB	3751	1333005	3,433.09	TIB	SDS/LGSS
37	12984606001	400471973	SGT	TIB	3736	1333026	7,848.80	TIB	SDS/LGSS
37	12984607002	400471965	SGT	TI4	3728	1333027	5,086.97	TI4	SDS/LGSS
37	12984611002	400471958	SGT	TIB	3723	1333029	7,465.84	TIB	SDS/LGSS
37	12984614001	400471948	SGT	TIB	3719	1333035	7,516.16	TIB	SDS/LGSS
37	12984622002	400471919	SGT	TAG6	3765	1333032	8,354.00	TAG6	SGSS2/SCD2/SGDS2
37	12984623001	400471918	SGT	TI4	4642	1333070	1,627.04	TI4	SDS/LGSS
37	12984624003	400471915	SGT	TIB	3763	1333032	6,546.35	TIB	SDS/LGSS
37	12984628004	400471893	SGT	TIB	3686	1333029	6,166.05	TIB	SDS/LGSS
37	12984639001	400471826	SGT	TAG6	3657	1333095	321.97	TAG6	SGSS2/SCD2/SGDS2
37	12984641001	400471812	SG2		4427	1333032	1,372.62	SG2	SGSS2/SCD2/SGDS2
37	12984643001	400471809	SGT	TIB	4526	1333017	4,064.30	TIB	SDS/LGSS
37	12984645001	400471795	SGT	TAG2	3777	1333095	272.52	TAG2	SGSS2/SCD2/SGDS2
37	12984661001	400526647	SGT	TI4	45046	1333014	2,190.07	TI4	SDS/LGSS
37	12984661003	400500358	SGT	TIB	14657	10101	23,195.59	TIB	SDS/LGSS
37	12984661004	500738669	SGT	TIB	48592	1333032	24,247.50	TIB	SDS/LGSS
37	13237020002	500135596	SGT	TI8	4638	511396	39,672.24	TI8	LDS/LGSS
37	13241895007	501021913	SGT	830	49028	30225	33,542.40	830	LDS/LGSS
37	13241895007	501028115	SGT	830	49013	30225	33,542.40	830	LDS/LGSS
37	13264345002	400520745	SG2		1306	1292913	3,173.68	SG2	SGSS2/SCD2/SGDS2
37	13266182003	400473258	SGT	850	1296	1252858	5,956.06	850	MDS/NSS
37	13270887001	500153389	SGT	TAG6	45693	273804	4,662.89	TAG6	SGSS2/SCD2/SGDS2
37	13333833001	500159224	LG1		45928	551501	6,394.31	LG1	SDS/LGSS
37	13409908003	800800444	SGT	TI4	289	70406	2,190.25	TI4	SDS/LGSS
37	13418879001	500171349	SGT	TIF	45520	30205	17,353.82	TIF	LDS/LGSS
37	13503540001	500099035	SGT	TI4	45872	1252862	11,513.92	TI4	SDS/LGSS
37	13606384001	500209675	SGT	TI8	46079	1333028	20,132.46	TI8	LDS/LGSS
37	13629199001	500199977	SGT	TIF	46006	1112521	41,218.18	TIF	LDS/LGSS
37	13637222011	400472011	SGT	TIB	3790	1333027	2,806.97	TIB	SDS/LGSS
37	13648145002	400473252	SC2		1289	1112521	24,071.02	SC2	SGSS2/SCD2/SGDS2
37	13658489004	500214064	SGT	TI4	47053	1252822	6,113.49	TI4	SDS/LGSS
37	13658489004	500459284	SGT	TI4	47484	1252822	5,248.14	TI4	SDS/LGSS
37	13676826001	500220820	SGT	845	46101	30243	27,319.26	845	LDS/LGSS
37	13801660001	500224592	SGT	TAG6	46122	1292998	17,889.42	TAG6	SGSS2/SCD2/SGDS2
37	13807449005	500843197	SGT	TAG6	48733	10160	18,037.95	TAG6	SGSS2/SCD2/SGDS2
37	13814290002	400495299	SGS		47969	10158	2,860.92	SGS	SGSS1/SCD1/SGDS1
37	13853322001	400473089	SGT	TI4	914	30225	5,076.33	TI4	SDS/LGSS
37	13874473001	400473157	SG2		979	70424	431.84	SG2	SGSS2/SCD2/SGDS2
37	13901909001	400485878	SGT	TI4	4254	30243	1,879.32	TI4	SDS/LGSS
37	13909661002	500239238	SGT	TI4	46384	1292918	6,129.30	TI4	SDS/LGSS
37	13941065002	400479518	SG2		774	30272	1,641.60	SG2	SGSS2/SCD2/SGDS2
37	13953098002	500268352	SG4		46701	511314	2,164.21	SG4	SGSS2/SCD2/SGDS2
37	13959263001	400473271	SGT	TI8	1309	1292977	12,519.67	TI8	LDS/LGSS
37	13968541002	500296548	SGT	TM3	46567	511324	229,989.90	TM3	MDS/NSS
37	14012426004	400516863	SG2		761	30272	1,955.21	SG2	SGSS2/SCD2/SGDS2
37	14136590002	500270120	SGT	TI4	48073	1252896	2,800.24	TI4	SDS/LGSS
37	14161090002	400473124	SGS		948	30265	1,320.90	SGS	SGSS1/SCD1/SGDS1
37	14161126001	400472230	SGT	TIB	3588	1333034	6,881.34	TIB	SDS/LGSS
37	14172457001	500278290	SGT	TAG6	46926	273804	9,112.62	TAG6	SGSS2/SCD2/SGDS2
37	14203427002	400483822	LG2		14283	511304	7,594.01	LG2	SDS/LGSS
37	14209858001	400473191	SGT	TIF	1007	30225	9,468.16	TIF	LDS/LGSS
37	14217110001	400478455	SG2		922	30272	1,504.84	SG2	SGSS2/SCD2/SGDS2
37	14238571001	500337814	SGT	TIF	46961	1333007	(820.17)	TIF	LDS/LGSS
37	14280523001	500327842	SGT	TI4	47308	273804	4,129.89	TI4	SDS/LGSS
37	14303963001	500391455	SGT	TAG6	47285	30260	12,719.37	TAG6	SGSS2/SCD2/SGDS2
37	14313747005	500338294	SGT	TAG6	47466	10155	12,693.66	TAG6	SGSS2/SCD2/SGDS2
37	14313747006	500323083	SGT	TAG6	48539	10155	4,383.45	TAG6	SGSS2/SCD2/SGDS2
37	14318082003	400519776	SGT	TIB	47451	1333032	10,445.94	TIB	SDS/LGSS
37	14344230001	500212008	SGT	TIB	47252	1252822	11,414.42	TIB	SDS/LGSS

37	14351364003	500354179	SGT	806	47333	591705	(9,801.11)	806	SDS/LGSS
37	14351364003	500371709	SGT	806	47605	591705	10,935.22	806	SDS/LGSS
37	14351364003	500690713	SGT	806	49040	591705	6,003.16	806	SDS/LGSS
37	14369089002	400516841	SG2		671	30272	1,557.14	SG2	SGSS2/SCD2/SGDS2
37	14381641008	500714270	SGT	TI4	48796	10119	1,125.17	TI4	SDS/LGSS
37	14436898001	400473532	SGT	TAG6	3380	832206	965.87	TAG6	SGSS2/SCD2/SGDS2
37	14471914001	400526560	SGT	TIF	3908	1333032	30,494.23	TIF	LDS/LGSS
37	14492769002	500965975	LG3		49158	1112521	20,695.18	LG3	LDS/LGSS
37	14529317003	400472635	SGT	840	1139	1252856	21,815.82	840	LDS/LGSS
37	14529317003	800800373	SGT	840	14246	1252856	13,412.22	840	LDS/LGSS
37	14557113003	500054098	SGT	TI4	48084	551501	30,701.18	TI4	SDS/LGSS
37	14623990006	400526769	SG2		4505	1333095	2,153.02	SG2	SGSS2/SCD2/SGDS2
37	14666681003	400472559	SG2		1077	30202	2,911.95	SG2	SGSS2/SCD2/SGDS2
37	14688568001	400473247	SGS		1286	1252858	6,713.97	SGS	SGSS1/SCD1/SGDS1
37	14738217002	400473525	SG4		621	832206	5,915.22	SG4	SGSS2/SCD2/SGDS2
37	14860718003	400473280	SGT	TI4	1313	511314	3,298.88	TI4	SDS/LGSS
37	14883214001	400472867	SG2		742	732195	2,101.78	SG2	SGSS2/SCD2/SGDS2
37	14906919001	400472894	SG3		3313	30260	6,641.74	SG3	SGSS1/SCD1/SGDS1
37	14930906001	400472018	SGT	TIB	3801	1333027	1,221.69	TIB	SDS/LGSS
37	14930906002	400472017	SGT	TIB	3800	1333027	183.89	TIB	SDS/LGSS
37	14958276003	500543371	SGT	TIB	35106	1112506	7,962.84	TIB	SDS/LGSS
37	14962898001	400504012	SGT	TAG6	4067	10104	1,319.79	TAG6	SGSS2/SCD2/SGDS2
37	14962907005	400500030	SGS		3454	190613	1,183.76	SGS	SGSS1/SCD1/SGDS1
37	14997023001	400472421	SGT	TI4	3491	10157	3,324.12	TI4	SDS/LGSS
37	15034438001	800800392	SGT	TAG6	1131	30298	630.15	TAG6	SGSS2/SCD2/SGDS2
37	15060779001	400526542	SGT	TIB	48868	1252805	14,168.94	TIB	SDS/LGSS
37	15077205001	400487433	SGT	TAG6	14445	1333095	4,352.73	TAG6	SGSS2/SCD2/SGDS2
37	15096104001	500587558	SGT	809	47842	732195	7,181.59	809	LDS/LGSS
37	15096104002	501033523	SGT	809	49045	732195	44,763.53	809	LDS/LGSS
37	15096113001	500587559	SGT	833	47843	732195	46,161.00	833	LDS/LGSS
37	15103065003	400526796	SGS		14835	10103	5,904.85	SGS	SGSS1/SCD1/SGDS1
37	15107817004	500136220	SG4		1438	511314	1,652.12	SG4	SGSS2/SCD2/SGDS2
37	15119666001	400472700	SG2		1198	30243	1,563.83	SG2	SGSS2/SCD2/SGDS2
37	15128021004	400472542	SGT	TIB	3278	30243	4,371.85	TIB	SDS/LGSS
37	15128021004	800800382	SGT	TIB	3279	30243	6,552.49	TIB	SDS/LGSS
37	15128021004	800800383	SGT	TIB	3280	30243	6,552.49	TIB	SDS/LGSS
37	15171839005	400472256	SGT	TI4	3642	1333074	279.49	TI4	SDS/LGSS
37	15190290003	500990795	SGT	TIB	48924	511314	21,953.37	TIB	SDS/LGSS
37	15246690003	400478147	SG2		1122	1252821	10,996.30	SG2	SGSS2/SCD2/SGDS2
37	15285794001	400520146	SGT	TIB	47452	1252807	398.38	TIB	SDS/LGSS
37	15285794005	400472715	SG2		1152	1252829	1,416.67	SG2	SGSS2/SCD2/SGDS2
37	15310256001	400477241	SGT	TIB	3990	1333017	60.31	TIB	SDS/LGSS
37	15320799002	400514006	SG4		4540	1252822	0.00	SG4	SGSS2/SCD2/SGDS2
37	15380130001	400500097	SGT	TIB	14666	10119	1,125.17	TIB	SDS/LGSS
37	15386979001	400472009	SGT	TIB	3788	1333027	5,065.69	TIB	SDS/LGSS
37	15399043001	400473272	SG4		1310	1292913	1,878.81	SG4	SGSS2/SCD2/SGDS2
37	15409498002	400472801	SG2		686	30225	1,621.75	SG2	SGSS2/SCD2/SGDS2
37	15410029001	400524934	SG4		1465	511314	2,137.32	SG4	SGSS2/SCD2/SGDS2
37	15410029003	400526421	SG2		1368	511314	5,237.34	SG2	SGSS2/SCD2/SGDS2
37	15514483001	400473294	SGS		1329	1112521	1,293.77	SGS	SGSS1/SCD1/SGDS1
37	15514517001	500607489	SGT	TI8	48514	551504	37,240.01	TI8	LDS/LGSS
37	15542189007	400484040	SG2		49239	1252829	16,540.14	SG2	SGSS2/SCD2/SGDS2
37	15542189008	500949435	SGS		49240	1252822	6,113.49	SGS	SGSS1/SCD1/SGDS1
37	15614278001	500732771	SGT	TI4	48561	30223	6,802.42	TI4	SDS/LGSS
37	15632066001	500494320	SGT	TIB	48533	1112512	11,191.32	TIB	SDS/LGSS
37	15641400003	400502082	SG4		46814	1333017	6,438.24	SG4	SGSS2/SCD2/SGDS2
37	15674018001	500648810	SGT	TIF	48541	273801	99,366.60	TIF	LDS/LGSS
37	15687805001	400495897	LG1		754	732195	1,702.73	LG1	SDS/LGSS
37	15772207001	400516842	SGT	TAG6	778	70409	2,886.58	TAG6	SGSS2/SCD2/SGDS2
37	15804397001	500153126	SGT	TI8	45642	70479	12,382.25	TI8	LDS/LGSS
37	15830301007	400476065	SGT	TI4	802	30209	2,082.57	TI4	SDS/LGSS
37	15878297001	500766884	SGT	TAG6	48455	1333007	61,122.20	TAG6	SGSS2/SCD2/SGDS2

37	15897246001	500635532	SGT	TIB	48654	1333004	10,255.49	TIB	SDS/LGSS
37	15932079001	500755822	SGT	TI8	48661	511311	11,097.65	TI8	LDS/LGSS
37	16032404001	400493513	SG2		3428	1112521	1,471.35	SG2	SGSS2/SCD2/SGDS2
37	16080397001	400520923	SG2		44426	190633	1,001.72	SG2	SGSS2/SCD2/SGDS2
37	16083526003	400472735	SG2		1224	30243	1,825.77	SG2	SGSS2/SCD2/SGDS2
37	16095038001	400517428	SGS		3385	190628	3,868.07	SGS	SGSS1/SCD1/SGDS1
37	16195289003	400472627	SGT	TAG6	1134	30276	3,736.41	TAG6	SGSS2/SCD2/SGDS2
37	16211690001	400522880	SGT	TAG6	1081	30243	1,018.27	TAG6	SGSS2/SCD2/SGDS2
37	16226888005	400288865	SGT	TIB	46395	1292977	1,878.55	TIB	SDS/LGSS
37	16226888005	400289580	SGT	TIB	46393	1292977	1,878.55	TIB	SDS/LGSS
37	16226888005	400473253	SGT	TIB	1290	1292977	16,200.79	TIB	SDS/LGSS
37	16251355005	800800440	SGT	TAG5	14268	70422	8,844.56	TAG5	SGSS1/SCD1/SGDS1
37	16266565001	400518893	SGT	TI8	934	70495	1,533.51	TI8	LDS/LGSS
37	16314259001	500845588	SGT	TAG5	48728	1333032	22,654.42	TAG5	SGSS1/SCD1/SGDS1
37	16316862001	400489632	SGT	TIB	48727	10103	23,457.97	TIB	SDS/LGSS
37	16343494001	400473488	SGS		631	832202	4,454.65	SGS	SGSS1/SCD1/SGDS1
37	16354507001	400485000	SG2		4273	1333014	3,108.54	SG2	SGSS2/SCD2/SGDS2
37	16450594001	400526719	SGT	TIB	48743	1333083	23,887.49	TIB	SDS/LGSS
37	16492890001	400472901	SG2		773	70478	1,571.94	SG2	SGSS2/SCD2/SGDS2
37	16512325001	400473207	SGS		4342	30272	991.08	SGS	SGSS1/SCD1/SGDS1
37	16512328001	400479318	SG2		4333	30272	1,468.09	SG2	SGSS2/SCD2/SGDS2
37	16618611001	400509341	SGT	TIB	14449	1333032	2,460.66	TIB	SDS/LGSS
37	16630957002	400526998	SGT	803	14788	70470	33,446.59	803	LDS/LGSS
37	16640613004	400472720	SG2		1212	30287	1,103.71	SG2	SGSS2/SCD2/SGDS2
37	16804444002	500146391	SGT	TI8	861	70495	10,233.82	TI8	LDS/LGSS
37	16804444008	500175309	SGT	TIB	49139	70495	11,223.75	TIB	SDS/LGSS
37	16869463001	400473316	LG2		1347	511311	8,455.09	LG2	SDS/LGSS
37	16894098002	500939482	SGT	TIB	49112	1333035	2,040.95	TIB	SDS/LGSS
37	16894098004	501057529	SGT	TI4	49129	1333035	2,040.95	TI4	SDS/LGSS
37	16919869001	500215263	SGT	TIB	48787	1333095	11,399.49	TIB	SDS/LGSS
37	16920048001	500959190	SGT	TIB	48797	511395	11,994.70	TIB	SDS/LGSS
37	16921777003	500191867	SGT	TIB	45616	273806	3,456.40	TIB	SDS/LGSS
37	16933818003	400472432	SGS		292	1333003	0.00	SGS	SGSS1/SCD1/SGDS1
37	17000719005	400496375	SG2		14550	1333027	1,701.93	SG2	SGSS2/SCD2/SGDS2
37	17001046003	400472146	SG2		3986	1333017	298.01	SG2	SGSS2/SCD2/SGDS2
37	17037445001	500962866	SGT	TIB	48814	511306	18,913.52	TIB	SDS/LGSS
37	17049920001	400499613	SGT	TIB	1126	30268	1,919.39	TIB	SDS/LGSS
37	17049920002	800800404	SG2		3463	30268	0.00	SG2	SGSS2/SCD2/SGDS2
37	17049929002	800800399	SG2		3458	30268	0.00	SG2	SGSS2/SCD2/SGDS2
37	17097990001	400473352	SGS		4547	1252858	1,965.53	SGS	SGSS1/SCD1/SGDS1
37	17120543005	400471994	SGT	TI4	3701	1333027	5,045.15	TI4	SDS/LGSS
37	17126427001	400526860	SG2		1250	30243	888.44	SG2	SGSS2/SCD2/SGDS2
37	17149672001	400526591	SGT	TAG6	799	732153	1,805.44	TAG6	SGSS2/SCD2/SGDS2
37	17184483002	500193058	SGT	TIB	45604	732195	2,191.46	TIB	SDS/LGSS
37	17187387006	400471902	SGT	TI8	4178	1333032	6,632.40	TI8	LDS/LGSS
37	17230495003	400479417	SG2		888	30225	1,962.15	SG2	SGSS2/SCD2/SGDS2
37	17264884002	400500238	SGT	TIH	14403	1333032	16,461.97	TIH	LDS/LGSS
37	17287297004	500966808	SGT	TIB	48842	10119	1,125.17	TIB	SDS/LGSS
37	17297010001	400474558	SGT	TI4	14055	1333035	8,795.26	TI4	SDS/LGSS
37	17329614003	500162630	SGT	868	44642	1333027	16,654.66	868	LDS/LGSS
37	17329614003	500162631	SGT	868	44642	1333027	16,654.66	868	LDS/LGSS
37	17374299002	400473323	LG1		1351	511314	9,043.84	LG1	SDS/LGSS
37	17377970001	501025433	SGT	TIB	48841	190626	24,015.97	TIB	SDS/LGSS
37	17409498001	501027922	SGT	TIB	49021	1333095	14,965.43	TIB	SDS/LGSS
37	17420756001	400504964	SGS		14778	1333017	2,579.81	SGS	SGSS1/SCD1/SGDS1
37	17432474003	400472075	SGT	TAG6	3879	1333027	1,428.34	TAG6	SGSS2/SCD2/SGDS2
37	17439660001	400471850	SGT	TI4	4149	1333035	290.07	TI4	SDS/LGSS
37	17439660003	800800314	SGT	TAG2	4269	1333035	2,586.96	TAG2	SGSS2/SCD2/SGDS2
37	17446577006	400498963	SGT	TI8	14518	10160	5,361.20	TI8	LDS/LGSS
37	17451537002	400473024	SG2		862	30272	1,519.38	SG2	SGSS2/SCD2/SGDS2
37	17486116001	501043836	SG4		49030	273821	5,529.58	SG4	SGSS2/SCD2/SGDS2
37	17509433003	501049268	SGT	TI8	49070	511306	21,499.07	TI8	LDS/LGSS

37	17515866004	501043874	SG2		49053	30224	1,718.88	SG2	SGSS2/SCD2/SGDS2
37	17515866005	501043873	SG2		49052	30224	1,718.88	SG2	SGSS2/SCD2/SGDS2
37	17520364002	501043872	SG2		49054	30224	1,718.88	SG2	SGSS2/SCD2/SGDS2
37	17556648001	500988325	LG1		49016	1252829	16,540.14	LG1	SDS/LGSS
37	17592775005	500935239	SG2		49241	1252828	2,221.29	SG2	SGSS2/SCD2/SGDS2
37	17613477001	501040193	SG2		49048	832295	17,028.50	SG2	SGSS2/SCD2/SGDS2
37	17653039001	400472681	SG2		1108	30243	1,885.74	SG2	SGSS2/SCD2/SGDS2
37	17662964001	400472829	SGT	856	711	30252	10,625.40	856	SDS/LGSS
37	17692241009	501080986	SGT	TIB	49302	1333017	75,979.41	TIB	SDS/LGSS
37	17697569001	400495886	SGT	TI4	14626	1333095	4,204.43	TI4	SDS/LGSS
37	17766386001	501049150	SGT	TIB	49088	1333014	37,624.94	TIB	SDS/LGSS
37	18505018001	400473396	SG2		3248	1292914	1,663.84	SG2	SGSS2/SCD2/SGDS2
37	18540737001	500487109	SGS		47705	1292909	37,052.17	SGS	SGSS1/SCD1/SGDS1
37	18553656001	500204877	SGT	TAG6	48298	30272	5,399.51	TAG6	SGSS2/SCD2/SGDS2
37	18660393001	501083309	SG2		40519	1252820	22,691.51	SG2	SGSS2/SCD2/SGDS2
37	18703892001	400505131	SGT	TIF	689	70477	23,230.13	TIF	LDS/LGSS
37	18776965001	400472097	SGT	TIF	3907	1333014	5,698.72	TIF	LDS/LGSS
37	18785500001	400474982	SG2		748	732195	1,700.15	SG2	SGSS2/SCD2/SGDS2
37	18792064002	501099066	SGT	TAG6	49244	1333035	15,923.45	TAG6	SGSS2/SCD2/SGDS2
37	18801361001	400472893	SG2		4537	190613	1,476.90	SG2	SGSS2/SCD2/SGDS2
37	18836110001	400473205	SGT	TIB	1018	732111	3,880.29	TIB	SDS/LGSS
37	18862516001	400506475	SGT	TIB	1050	1252806	869.86	TIB	SDS/LGSS
37	18876998001	400498570	SG4		14594	310911	7,789.73	SG4	SGSS2/SCD2/SGDS2
37	18885421001	500376080	SGT	TIB	49156	10119	16,954.88	TIB	SDS/LGSS
37	18897692003	400472409	SGT	TIB	1512	10160	3,247.68	TIB	SDS/LGSS
37	18917876001	400474751	SGT	TI4	4509	30223	3,241.16	TI4	SDS/LGSS
37	18929586001	400526210	SGT	TAG6	723	30272	2,110.65	TAG6	SGSS2/SCD2/SGDS2
37	18938679001	500744795	SGT	872	49242	1252851	29,234.93	872	MDS/NSS
37	18941652003	400473297	SGS		1332	511318	3,863.92	SGS	SGSS1/SCD1/SGDS1
37	18973174002	400526191	SGT	873	44761	190613	81,514.47	873	LDS/LGSS
37	18985473001	501047288	SGT	TIB	49243	1333035	450.56	TIB	SDS/LGSS
37	19022293001	400473231	SG2		4575	511316	1,956.84	SG2	SGSS2/SCD2/SGDS2
37	19022293005	500132845	SG2		4575	511316	1,956.84	SG2	SGSS2/SCD2/SGDS2
37	19046540001	400508038	SGT	TIB	14064	1333017	1,758.34	TIB	SDS/LGSS
37	19074397001	501115733	SGT	TI8	49265	1333017	1,216.31	TI8	LDS/LGSS
37	19075101001	400473322	SGS		4421	1292916	10,041.93	SGS	SGSS1/SCD1/SGDS1
37	19084905001	500758287	SG2		49126	1333017	6,438.24	SG2	SGSS2/SCD2/SGDS2
37	19114953001	500688577	SGT	TAG6	48544	511312	1,115.13	TAG6	SGSS2/SCD2/SGDS2
37	19117144005	501102841	SGT	TI8	49282	732108	0.00	TI8	LDS/LGSS
37	19117144005	501104644	SGT	TI8	49270	732108	44,938.18	TI8	LDS/LGSS
37	19179996001	400472978	SGT	TIG	828	30272	21,799.23	TIG	LDS/LGSS
37	19188658001	400472929	LG2		797	30225	677.14	LG2	SDS/LGSS
37	19193822001	501050977	SGT	TAG6	49272	10103	11,227.06	TAG6	SGSS2/SCD2/SGDS2
37	19195813001	400472866	SG2		741	70470	12,018.67	SG2	SGSS2/SCD2/SGDS2
37	19198302001	400472903	SG2		775	732195	6,051.86	SG2	SGSS2/SCD2/SGDS2
37	19212239003	500791830	SGT	TIB	49025	30201	0.00	TIB	SDS/LGSS
37	19234486001	400472905	SC2		777	732153	1,248.09	SC2	SGSS2/SCD2/SGDS2
37	19252407003	800800378	SGT	TAG6	849	30234	2,908.76	TAG6	SGSS2/SCD2/SGDS2
37	19261707001	400475636	SGT	TIB	793	30223	3,586.35	TIB	SDS/LGSS
37	19297438001	400493366	SGT	TIF	14458	1333025	7,246.78	TIF	LDS/LGSS
37	19336466001	400501188	SGT	TAG2	45609	1333032	7,478.06	TAG2	SGSS2/SCD2/SGDS2
37	19430896001	501122186	SGT	TIB	49298	70412	11,219.30	TIB	SDS/LGSS
37	19431194001	400473171	SGT	TIB	989	70461	20,862.41	TIB	SDS/LGSS
37	19441257001	500095996	SG2		46960	1333017	6,468.85	SG2	SGSS2/SCD2/SGDS2
37	19443642001	400472814	SGT	TIB	697	70403	8,081.85	TIB	SDS/LGSS
37	19447200001	400472448	LG1		4581	273851	1,817.71	LG1	SDS/LGSS
37	19447200003	500153394	LG1		4581	273851	1,817.71	LG1	SDS/LGSS
37	19457137001	400473264	LG1		1303	511314	1,557.22	LG1	SDS/LGSS
37	19510781001	400500023	SG2		4557	190613	2,115.02	SG2	SGSS2/SCD2/SGDS2
37	19531601001	400526383	LG1		1012	30225	11,619.73	LG1	SDS/LGSS
37	19592009001	501155646	LG2		49311	1292909	23,792.01	LG2	SDS/LGSS
37	19623332001	400472345	SG2		3562	1333063	7,786.78	SG2	SGSS2/SCD2/SGDS2

37	19628523001	800800406	SGT	TAG6	14727	30268	0.00	TAG6	SGSS2/SCD2/SGDS2
37	19643824001	400473062	SG2		891	732195	3,376.52	SG2	SGSS2/SCD2/SGDS2
37	19682099001	500296730	SGT	TIB	46707	511304	15,095.42	TIB	SDS/LGSS
37	19690771001	400054367	SGT	TAG6	47475	1333025	25,691.99	TAG6	SGSS2/SCD2/SGDS2
37	19701638001	400525221	SGS		44523	30209	8,165.63	SGS	SGSS1/SCD1/SGDS1
37	19705889001	400472211	SGT	TIB	3644	1333074	5,364.81	TIB	SDS/LGSS
37	19791817001	500175440	LG3		45528	70452	16,374.96	LG3	LDS/LGSS
37	19817465001	400472437	LG2		3304	10104	11,234.53	LG2	SDS/LGSS
	Total								

	Total Cost	Percent
RSS/RTS	0.00	0.000%
SGSS1/SCD1/SGDS1	206,786.35	4.008%
SGSS2/SCD2/SGDS2	950,546.90	18.422%
SDS/LGSS	2,131,615.53	41.312%
LDS/LGSS	1,870,805.34	36.258%
TOTAL BEFORE MDS/NSS	5,159,754.12	100.000%
MDS/NSS	373,935.42	
TOTAL	5,533,689.54	

EXHIBIT MPB-2
ALLOC 18

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 18
OTHER DISTRIBUTION O & M EXPENSE

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	871.00	LOAD DISPATCHING	196,090	147,795	17,605	14,997	7,879	7,765	49
2	874.00	MAINS & SERVICES	16,897,282	13,395,320	1,448,097	1,031,579	516,043	502,863	3,380
3	875.00	M & R - GENERAL	467,159	352,103	41,942	35,728	18,770	18,500	117
4	876.00	M & R - INDUSTRIAL	295,774	-	11,855	54,488	122,190	107,242	-
5	878.00	METERS & HOUSE REGULATORS	2,644,529	2,028,592	118,369	466,786	23,801	6,611	370
6	879.00	CUSTOMER INSTALLATIONS	6,208,923	5,638,137	457,349	96,176	12,853	4,408	-
7	886.00	STRUCTURES AND IMPROVEMENT	167,094	125,941	15,002	12,779	6,714	6,617	42
8	887.00	MAINS	15,793,235	11,903,519	1,417,917	1,207,867	634,572	625,412	3,948
9	889.00	M & R - GENERAL	967,327	729,084	86,847	73,981	38,867	38,306	242
10	890.00	M & R - INDUSTRIAL	178,953	-	7,172	32,967	73,929	64,885	-
11	892.00	SERVICES	4,367,301	3,965,815	321,695	67,650	9,040	3,101	-
12	893.00	METERS & HOUSE REGULATORS	269,059	206,393	12,043	47,492	2,422	673	38
13		TOTAL	48,452,726	38,492,697	3,955,892	3,142,489	1,467,080	1,386,382	8,185
14		**ALLOCATOR #18**	100.000%	79.444%	8.164%	6.486%	3.028%	2.861%	0.017%

EXHIBIT MPB-2
ALLOC 19

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 19
O & M EXCLUDING GAS PURCHASED COST, UNCOLLECTIBLES, USP COSTS & A & G

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1		TOTAL PURCH GAS & UNDERGROUND STORAGE	125,440,341	91,145,441	14,631,914	16,387,989	2,771,119	229,043	274,835
2		TOTAL DISTRIBUTION O&M [2]	64,136,331	50,952,381	5,236,302	4,159,727	1,941,980	1,835,090	10,851
3		TOTAL CUSTOMER ACCOUNTS [3]	27,579,454	25,866,080	1,012,788	356,949	170,872	157,846	14,919
4		TOTAL CUSTOMER SERVICE & INFORMATION [4]	12,639,506	12,475,511	134,927	26,294	2,341	409	23
5		TOTAL SALES [5]	698,570	636,914	50,723	9,885	880	154	14
6		TOTAL	230,494,202	181,076,327	21,066,655	20,940,844	4,887,192	2,222,542	300,643
	LESS:								
7		GAS PURCHASED COST [6]	124,134,259	90,195,150	14,478,538	16,218,817	2,742,911	226,707	272,136
8	904.00	UNCOLLECTIBLES-DIS REVENUE [7]	4,023,302	3,761,667	129,068	132,568	-	-	-
9	904.00	UNCOLLECTIBLES-GMB/GTS REVENUE [8]	343,733	-	581	16,369	156,715	155,374	14,695
10	904.00	UNCOLLECTIBLES-UNBUNDLED GAS [9]	1,053,828	964,626	42,504	46,698	-	-	-
11	904.00	DIRECT USP UNCOLLECTIBLES [10]	10,307,864	10,307,864	-	-	-	-	-
12	908.00	DIRECT USP/LIURP/HEEP [11]	10,781,262	10,781,262	-	-	-	-	-
13		TOTAL	150,644,248	116,010,569	14,650,690	16,414,451	2,899,626	382,081	286,831
14		TOTAL	79,849,954	65,065,758	6,415,964	4,526,393	1,987,567	1,840,460	13,812
15		**ALLOCATOR #19**	100.000%	81.485%	8.035%	5.669%	2.489%	2.305%	0.017%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

1 **Total Company - Average Unit Cost of Mains**

2				Total Company		Direct Assignment		Allocable Pipe		Average
3	Kind	Size	Key	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Cost per Foot
4	CAST IRON	3"	CAST IRON 3"	8,799	9,295	-	-	8,799	9,295	1.06
5	CAST IRON	4"	CAST IRON 4"	102,696	266,265	-	-	102,696	266,265	2.59
6	CAST IRON	6"	CAST IRON 6"	33,446	80,873	-	-	33,446	80,873	2.42
7	CAST IRON	8"	CAST IRON 8"	13,471	66,288	-	-	13,471	66,288	4.92
8	CAST IRON	10"	CAST IRON 10"	2,202	8,506	-	-	2,202	8,506	3.86
9	CAST IRON	12"	CAST IRON 12"	867	58,051	-	-	867	58,051	66.96
10	PLASTIC	1"	PLASTIC 1"	30,285	133,100	-	-	30,285	133,100	4.39
11	PLASTIC	1-1/8"	PLASTIC 1-1/8"	1,402	5,709	-	-	1,402	5,709	4.07
12	PLASTIC	1-1/4"	PLASTIC 1-1/4"	387,698	2,179,025	-	-	387,698	2,179,025	5.62
13	PLASTIC	2"	PLASTIC 2"	9,831,105	135,539,936	-	-	9,831,105	135,539,936	13.79
14	PLASTIC	3"	PLASTIC 3"	2,268,335	27,626,828	-	-	2,268,335	27,626,828	12.18
15	PLASTIC	4"	PLASTIC 4"	5,962,527	245,379,171	808	58,818	5,961,719	245,320,353	41.15
16	PLASTIC	6"	PLASTIC 6"	2,290,954	150,581,221	645	20,688	2,290,309	150,560,533	65.74
17	PLASTIC	8"	PLASTIC 8"	1,125,665	108,324,662	-	-	1,125,665	108,324,662	96.23
18	STEEL	1/2"	STEEL 1/2"	3	233	-	-	3	233	77.74
19	STEEL	3/4"	STEEL 3/4"	7,104	13,286	-	-	7,104	13,286	1.87
20	STEEL	1"	STEEL 1"	41,334	104,463	-	-	41,334	104,463	2.53
21	STEEL	1-1/4"	STEEL 1-1/4"	282,941	767,174	-	-	282,941	767,174	2.71
22	STEEL	1-1/2"	STEEL 1-1/2"	11,436	12,618	-	-	11,436	12,618	1.10
23	STEEL	2"	STEEL 2"	3,461,005	9,150,861	840	4,331	3,460,165	9,146,531	2.64
24	STEEL	2-1/2"	STEEL 2-1/2"	4,740	3,178	-	-	4,740	3,178	0.67
25	STEEL	3"	STEEL 3"	1,017,996	2,988,692	-	-	1,017,996	2,988,692	2.94
26	STEEL	3-1/4"	STEEL 3-1/4"	653	3,764	-	-	653	3,764	5.76
27	STEEL	3-1/2"	STEEL 3-1/2"	8,138	27,318	-	-	8,138	27,318	3.36
28	STEEL	4"	STEEL 4"	5,386,015	23,941,148	4,809	26,695	5,381,206	23,914,453	4.44
29	STEEL	4-1/2"	STEEL 4-1/2"	1,458	24,094	-	-	1,458	24,094	16.53
30	STEEL	4-7/8"	STEEL 4-7/8"	13,967	18,898	-	-	13,967	18,898	1.35
31	STEEL	5"	STEEL 5"	46,546	51,374	93	41	46,453	51,333	1.11
32	STEEL	5-3/16"	STEEL 5-3/16"	19,365	37,805	-	-	19,365	37,805	1.95
33	STEEL	5-1/4"	STEEL 5-1/4"	621	344	-	-	621	344	0.55
34	STEEL	5-1/2"	STEEL 5-1/2"	295	343	-	-	295	343	1.16
35	STEEL	5-5/8"	STEEL 5-5/8"	21,067	22,053	-	-	21,067	22,053	1.05
36	STEEL	6"	STEEL 6"	3,320,548	31,564,756	17,105	126,426	3,303,443	31,438,331	9.52
37	STEEL	6-1/4"	STEEL 6-1/4"	18,188	5,811	-	-	18,188	5,811	0.32
38	STEEL	6-5/8"	STEEL 6-5/8"	110,652	694,540	-	-	110,652	694,540	6.28
39	STEEL	7-5/8"	STEEL 7-5/8"	2,336	12,224	-	-	2,336	12,224	5.23
40	STEEL	8"	STEEL 8"	1,631,542	45,481,057	-	-	1,631,542	45,481,057	27.88
41	STEEL	8-1/4"	STEEL 8-1/4"	282	2,429	-	-	282	2,429	8.61
42	STEEL	8-5/8"	STEEL 8-5/8"	8,232	361,804	-	-	8,232	361,804	43.95
43	STEEL	9-5/8"	STEEL 9-5/8"	1,269	7,380	-	-	1,269	7,380	5.82
44	STEEL	10"	STEEL 10"	758,897	21,889,932	-	-	758,897	21,889,932	28.84
45	STEEL	12"	STEEL 12"	422,485	30,137,252	-	-	422,485	30,137,252	71.33
46	STEEL	14"	STEEL 14"	450	5,167	-	-	450	5,167	11.48
47	STEEL	16"	STEEL 16"	330,022	17,576,276	-	-	330,022	17,576,276	53.26
48	STEEL	20"	STEEL 20"	34,198	6,960,022	-	-	34,198	6,960,022	203.52
49	WROUGHT IRON	2"	WROUGHT IRON 2"	31,359	25,521	-	-	31,359	25,521	0.81
50	WROUGHT IRON	3"	WROUGHT IRON 3"	54,892	7,999	-	-	54,892	7,999	0.15

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: M. BALMERT

				Total Company		Direct Assignment		Allocable Pipe		Average
1	**Total Company - Average Unit Cost of Mains (Cont)**									
2				Total Company		Direct Assignment		Allocable Pipe		Average
3	Kind	Size	Key	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Quantity (Footage)	Amount	Cost per Foot
4	WROUGHT IRON	4"	WROUGHT IRON 4"	71,351	4,358	-	-	71,351	4,358	0.06
5	WROUGHT IRON	6"	WROUGHT IRON 6"	74,382	254	-	-	74,382	254	0.00
6	WROUGHT IRON	6-5/8"	WROUGHT IRON 6-5/8"	1,622	151	-	-	1,622	151	0.09
7	WROUGHT IRON	8"	WROUGHT IRON 8"	156,604	2,311	-	-	156,604	2,311	0.01
8	WROUGHT IRON	10"	WROUGHT IRON 10"	69,435	683	-	-	69,435	683	0.01
9	WROUGHT IRON	12"	WROUGHT IRON 12"	9,122	5,721	-	-	9,122	5,721	0.63
10	Total Pipe			39,492,004	862,172,225	24,300	236,998	39,467,704	861,935,226	21.84
11	OTHER NON-PIPE				240,846,335		119,403		240,726,933	
12	Total Account 376				1,103,018,560		356,401		1,102,662,159	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: M. BALMERT

1	**Total Company - Transmission Class Mains**					
2					Average	
3	Kind	Size	Key	Quantity	Unit Cost	Amount
4	STEEL	10"	STEEL 10"	31,301	28.84	902,720.84
5	STEEL	12"	STEEL 12"	69,551	71.33	4,961,072.83
6	STEEL	16"	STEEL 16"	29,614	53.26	1,577,241.64
7	STEEL	2"	STEEL 2"	2,839	2.64	7,494.96
8	STEEL	4"	STEEL 4"	8,853	4.44	39,307.32
9	STEEL	6"	STEEL 6"	716	9.52	6,816.32
10	STEEL	8"	STEEL 8"	160,093	27.88	4,463,392.84
11	STEEL	1-1/2"	STEEL 1-1/2"	77	1.10	84.70
12	STEEL	3"	STEEL 3"	969	2.94	2,848.86
13	Total			304,013		11,960,980.31

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: M. BALMERT

1	**Total Company - Distribution Low Pressure Mains**					
2					Average	
3	Kind	Size	Key	Quantity	Unit Cost	Amount
4	CAST IRON	3"	CAST IRON 3"	6,878	1.06	7,290.68
5	CAST IRON	4"	CAST IRON 4"	49,838	2.59	129,080.42
6	CAST IRON	6"	CAST IRON 6"	17,172	2.42	41,556.24
7	CAST IRON	8"	CAST IRON 8"	5,467	4.92	26,897.64
8	CAST IRON	10"	CAST IRON 10"	479	3.86	1,848.94
9	CAST IRON	12"	CAST IRON 12"	330	66.96	22,096.80
10	PLASTIC	1"	PLASTIC 1"	7,412	4.39	32,538.68
11	PLASTIC	1-1/8"	PLASTIC 1-1/8"	1,120	4.07	4,558.40
12	PLASTIC	1-1/4"	PLASTIC 1-1/4"	65,966	5.62	370,728.92
13	PLASTIC	2"	PLASTIC 2"	1,173,558	13.79	16,183,364.82
14	PLASTIC	3"	PLASTIC 3"	770,489	12.18	9,384,556.02
15	PLASTIC	4"	PLASTIC 4"	1,858,556	41.15	76,479,579.40
16	PLASTIC	6"	PLASTIC 6"	704,944	65.74	46,343,018.56
17	PLASTIC	8"	PLASTIC 8"	234,696	96.23	22,584,796.08
18	STEEL	1/2"	STEEL 1/2"	0	77.74	0.00
19	STEEL	3/4"	STEEL 3/4"	0	1.87	0.00
20	STEEL	1"	STEEL 1"	4,342	2.53	10,985.26
21	STEEL	1-1/4"	STEEL 1-1/4"	13,929	2.71	37,747.59
22	STEEL	1-1/2"	STEEL 1-1/2"	5,104	1.10	5,614.40
23	STEEL	2"	STEEL 2"	831,443	2.64	2,195,009.52
24	STEEL	2-1/2"	STEEL 2-1/2"	2,852	0.67	1,910.84
25	STEEL	3"	STEEL 3"	518,632	2.94	1,524,778.08
26	STEEL	3-1/4"	STEEL 3-1/4"	0	5.76	0.00
27	STEEL	3-1/2"	STEEL 3-1/2"	6,682	3.36	22,451.52
28	STEEL	4"	STEEL 4"	2,650,370	4.44	11,767,642.80
29	STEEL	4-1/2"	STEEL 4-1/2"	710	16.53	11,736.30
30	STEEL	4-7/8"	STEEL 4-7/8"	11,071	1.35	14,945.85
31	STEEL	5"	STEEL 5"	23,389	1.11	25,961.79
32	STEEL	5-3/16"	STEEL 5-3/16"	10,869	1.95	21,194.55
33	STEEL	5-1/4"	STEEL 5-1/4"	56	0.55	30.80
34	STEEL	5-1/2"	STEEL 5-1/2"	295	1.16	342.20
35	STEEL	5-5/8"	STEEL 5-5/8"	18,917	1.05	19,862.85
36	STEEL	6"	STEEL 6"	1,480,276	9.52	14,092,227.52
37	STEEL	6-1/4"	STEEL 6-1/4"	11,121	0.32	3,558.72
38	STEEL	6-5/8"	STEEL 6-5/8"	85,816	6.28	538,924.48
39	STEEL	8"	STEEL 8"	260,393	27.88	7,259,756.84
40	STEEL	8-1/4"	STEEL 8-1/4"	0	8.61	0.00
41	STEEL	8-5/8"	STEEL 8-5/8"	0	43.95	0.00
42	STEEL	9-5/8"	STEEL 9-5/8"	0	5.82	0.00
43	STEEL	10"	STEEL 10"	158,325	28.84	4,566,093.00
44	STEEL	12"	STEEL 12"	32,801	71.33	2,339,695.33
45	STEEL	14"	STEEL 14"	450	11.48	5,166.00
46	STEEL	16"	STEEL 16"	18,953	53.26	1,009,436.78
47	STEEL	20"	STEEL 20"	1,532	203.52	311,792.64

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: M. BALMERT

1	**Total Company - Distribution Low Pressure Mains (Cont)**					
2					Average	
3	Kind	Size	Key	Quantity	Unit Cost	Amount
4	WROUGHT IRON	2"	WROUGHT IRON 2"	720	0.81	583.20
5	WROUGHT IRON	3"	WROUGHT IRON 3"	2,866	0.15	429.90
6	WROUGHT IRON	4"	WROUGHT IRON 4"	7,836	0.06	470.16
7	WROUGHT IRON	6"	WROUGHT IRON 6"	1,956	0.00	0.00
8	WROUGHT IRON	6-5/8"	WROUGHT IRON 6-5/8"	0	0.09	0.00
9	WROUGHT IRON	8"	WROUGHT IRON 8"	1,457	0.01	14.57
10	WROUGHT IRON	10"	WROUGHT IRON 10"	553	0.01	5.53
11	WROUGHT IRON	12"	WROUGHT IRON 12"	0	0.63	0.00
12	Total			11,060,621		217,400,280.62

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: M. BALMERT

1 **Total Company - Distribution Regulated Pressure Only Mains**

2				Total	Direct Assignment	Allocable	Average	
3	Kind	Size	Key	Quantity	Quantity	Quantity	Unit Cost	Amount
4	CAST IRON	4"	CAST IRON 4"	0	0	0	2.59	0.00
5	PLASTIC	1-1/4"	PLASTIC 1-1/4"	321,732	0	321,732	5.62	1,808,133.84
6	PLASTIC	2"	PLASTIC 2"	8,351,676	0	8,351,676	13.79	115,169,612.04
7	PLASTIC	3"	PLASTIC 3"	1,386,303	0	1,386,303	12.18	16,885,170.54
8	PLASTIC	4"	PLASTIC 4"	3,655,363	808	3,654,555	41.15	150,384,938.25
9	PLASTIC	6"	PLASTIC 6"	1,116,332	0	1,116,332	65.74	73,387,665.68
10	PLASTIC	8"	PLASTIC 8"	346,856	0	346,856	96.23	33,377,952.88
11	STEEL	1-1/4"	STEEL 1-1/4"	269,012	0	269,012	2.71	729,022.52
12	STEEL	2"	STEEL 2"	2,648,561	0	2,648,561	2.64	6,992,201.04
13	STEEL	3"	STEEL 3"	424,750	0	424,750	2.94	1,248,765.00
14	STEEL	4"	STEEL 4"	2,062,511	0	2,062,511	4.44	9,157,548.84
15	STEEL	5"	STEEL 5"	23,157	93	23,064	1.11	25,601.04
16	STEEL	6"	STEEL 6"	875,673	0	875,673	9.52	8,336,406.96
17	STEEL	8"	STEEL 8"	428,639	0	428,639	27.88	11,950,455.32
18	STEEL	10"	STEEL 10"	43,296	0	43,296	28.84	1,248,656.64
19	STEEL	12"	STEEL 12"	65,152	0	65,152	71.33	4,647,292.16
20	STEEL	16"	STEEL 16"	32,346	0	32,346	53.26	1,722,747.96
21	STEEL	20"	STEEL 20"	88	0	88	203.52	17,909.76
22	WROUGHT IRON	2"	WROUGHT IRON 2"	4,106	0	4,106	0.81	3,325.86
23	WROUGHT IRON	6"	WROUGHT IRON 6"	17,043	0	17,043	0.00	0.00
24	WROUGHT IRON	8"	WROUGHT IRON 8"	39,570	0	39,570	0.01	395.70
25	Total			22,112,166	901	22,111,265		437,093,802.03

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: M. BALMERT

1	**Total Company - Remaining Regulated Pressure Mains**						
2					Direct Assignment	Allocable	
3	Kind	Size	Key	Quantity	Quantity	Quantity	Amount
4	CAST IRON	3"	CAST IRON 3"	1,921	0	1,921	2,004.55
5	CAST IRON	4"	CAST IRON 4"	52,858	0	52,858	137,184.34
6	CAST IRON	6"	CAST IRON 6"	16,274	0	16,274	39,317.13
7	CAST IRON	8"	CAST IRON 8"	8,004	0	8,004	39,390.26
8	CAST IRON	10"	CAST IRON 10"	1,723	0	1,723	6,657.02
9	CAST IRON	12"	CAST IRON 12"	537	0	537	35,954.08
10	PLASTIC	1"	PLASTIC 1"	22,873	0	22,873	100,561.06
11	PLASTIC	1-1/8"	PLASTIC 1-1/8"	282	0	282	1,150.85
12	PLASTIC	1-1/4"	PLASTIC 1-1/4"	0	0	0	162.41
13	PLASTIC	2"	PLASTIC 2"	305,871	0	305,871	4,186,958.93
14	PLASTIC	3"	PLASTIC 3"	111,543	0	111,543	1,357,101.25
15	PLASTIC	4"	PLASTIC 4"	448,608	0	448,608	18,455,835.55
16	PLASTIC	6"	PLASTIC 6"	469,678	645	469,033	30,829,848.89
17	PLASTIC	8"	PLASTIC 8"	544,113	0	544,113	52,361,912.74
18	STEEL	1/2"	STEEL 1/2"	3	0	3	233.23
19	STEEL	3/4"	STEEL 3/4"	7,104	0	7,104	13,286.39
20	STEEL	1"	STEEL 1"	36,992	0	36,992	93,477.85
21	STEEL	1-1/4"	STEEL 1-1/4"	0	0	0	404.09
22	STEEL	1-1/2"	STEEL 1-1/2"	6,255	0	6,255	6,918.51
23	STEEL	2"	STEEL 2"	(21,838)	840	(22,678)	(48,174.95)
24	STEEL	2-1/2"	STEEL 2-1/2"	1,888	0	1,888	1,266.97
25	STEEL	3"	STEEL 3"	73,645	0	73,645	212,299.98
26	STEEL	3-1/4"	STEEL 3-1/4"	653	0	653	3,764.26
27	STEEL	3-1/2"	STEEL 3-1/2"	1,456	0	1,456	4,866.84
28	STEEL	4"	STEEL 4"	664,281	4,809	659,472	2,949,953.96
29	STEEL	4-1/2"	STEEL 4-1/2"	748	0	748	12,357.74
30	STEEL	4-7/8"	STEEL 4-7/8"	2,896	0	2,896	3,952.38
31	STEEL	5"	STEEL 5"	0	0	0	(229.51)
32	STEEL	5-3/16"	STEEL 5-3/16"	8,496	0	8,496	16,610.86
33	STEEL	5-1/4"	STEEL 5-1/4"	565	0	565	313.27
34	STEEL	5-1/2"	STEEL 5-1/2"	0	0	0	1.22
35	STEEL	5-5/8"	STEEL 5-5/8"	2,150	0	2,150	2,189.85
36	STEEL	6"	STEEL 6"	963,883	17,105	946,778	9,002,879.74
37	STEEL	6-1/4"	STEEL 6-1/4"	7,067	0	7,067	2,251.81
38	STEEL	6-5/8"	STEEL 6-5/8"	24,836	0	24,836	155,615.09
39	STEEL	7-5/8"	STEEL 7-5/8"	2,336	0	2,336	12,224.00
40	STEEL	8"	STEEL 8"	782,417	0	782,417	21,807,452.44
41	STEEL	8-1/4"	STEEL 8-1/4"	282	0	282	2,429.17
42	STEEL	8-5/8"	STEEL 8-5/8"	8,232	0	8,232	361,803.89
43	STEEL	9-5/8"	STEEL 9-5/8"	1,269	0	1,269	7,379.67
44	STEEL	10"	STEEL 10"	525,975	0	525,975	15,172,461.11
45	STEEL	12"	STEEL 12"	254,981	0	254,981	18,189,191.90
46	STEEL	14"	STEEL 14"	0	0	0	0.88
47	STEEL	16"	STEEL 16"	249,109	0	249,109	13,266,849.23

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: M. BALMERT

1	Total Company - Remaining Regulated Pressure Mains (Cont)						
2					Direct Assignment	Allocable	
3	Kind	Size	Key	Quantity	Quantity	Quantity	Amount
4	STEEL	20"	STEEL 20"	32,578	0	32,578	6,630,319.24
5	WROUGHT IRON	2"	WROUGHT IRON 2"	26,533	0	26,533	21,611.74
6	WROUGHT IRON	3"	WROUGHT IRON 3"	52,026	0	52,026	7,569.17
7	WROUGHT IRON	4"	WROUGHT IRON 4"	63,515	0	63,515	3,888.11
8	WROUGHT IRON	6"	WROUGHT IRON 6"	55,383	0	55,383	254.09
9	WROUGHT IRON	6-5/8"	WROUGHT IRON 6-5/8"	1,622	0	1,622	150.66
10	WROUGHT IRON	8"	WROUGHT IRON 8"	115,577	0	115,577	1,900.53
11	WROUGHT IRON	10"	WROUGHT IRON 10"	68,882	0	68,882	677.66
12	WROUGHT IRON	12"	WROUGHT IRON 12"	9,122	0	9,122	5,721.31
13	Total			6,015,204	23,399	5,991,805	195,480,163.44

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: M. BALMERT

Line No.	Description	Alloc	Total Company	RS/RDS	SGS/SGDS	LGS	SDS	LDS	MDS
	Total Mains Plant in Service		1,103,018,560.14						
	Direct Assigned Plant		236,998.27						
	Other - Non Pipe		240,846,335.47						
	Allocable Pipe		861,935,226.40						
1	**Transmission Pipe**		11,960,980.31						
2	**Low Pressure Pipe**		217,400,280.62						
3	**Regulated Pressure Pipe Only**		437,093,802.03						
4	**Remaining Regulated Pressure Pipe**		195,480,163.44						
5	**Allocated Pipe**		861,935,226.40						
6									
7	**Allocation of Transmission Pipe**								
8	Allocable Transmission Pipe		$11,960,980.31						
9	Design Day Volumes (Total Company Excluding MDS)		769,993	441,900	82,752	109,891	63,707	71,743	
10	Percent Design Day Volumes		100.000%	57.390%	10.747%	14.272%	8.274%	9.317%	
11	**Allocation of Transmission Pipe**		**$11,960,980.31**	**$6,864,406.60**	**$1,285,446.55**	**$1,707,071.11**	**989,651.51**	**1,114,404.54**	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: M. BALMERT

Line No.	Description	Alloc	Total Company	RS/RDS	SGS1/SCD1/SGDS1	SGS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MDS
1	**Allocation of Low Pressure Pipe**								
2			Footage	Amount	Unit Cost				
3	2" Pipe		2,005,721	18,378,957.54	$9.16				
4	All Pipe		11,060,621	217,400,280.62					
5	Unit Cost of 2" x All Pipe Footage			101,315,288.36					
6	Customer Component			46.603%					
7	Demand Component			53.397%					
8	Allocable Low Pressure Pipe		$217,400,280.62						
9	Number of Customers (excl MDS)		181,583	166,658	13,272	1,632	20	1	
10	Percent Customers		100.000%	91.780%	7.309%	0.899%	0.011%	0.001%	
11	Customer Component		46.603%	42.772%	3.406%	0.419%	0.005%	0.000%	
12	Design Day Volumes (excl MDS)		267,164	208,600	33,480	23,721	1,360	3	
13	Percent Design Day Volumes		100.000%	78.079%	12.532%	8.879%	0.509%	0.001%	
14	Demand Component		53.397%	41.692%	6.692%	4.741%	0.272%	0.001%	
15	Minimum System Allocation Factor		100.000%	84.464%	10.098%	5.160%	0.277%	0.001%	
16	**Allocation of Low Pressure Pipe**		$217,400,280.62	$183,624,973.02	$21,953,080.34	$11,217,854.48	602,198.78	2,174.00	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: M. BALMERT

Line No.	Description	Alloc	Total Company	RS/RDS	SGS1/SCD1/SGDS1	SGS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MDS
1	**Allocation of Regulated Pressure Pipe Only**								
2			Footage	Amount	Unit Cost				
3	2" Pipe		11,004,343	122,165,138.94	$11.10				
4	All Pipe		22,111,265	437,093,802.03					
5	Unit Cost of 2" x All Pipe Footage			245,435,041.50					
6	Customer Component			56.152%					
7	Demand Component			43.848%					
8	Allocable Regulated Pressure Only Pipe		$437,093,802.03						
9	Number of Customers (excl MDS)		162,513	148,163	11,467	2,651	198	34	
10	Percent Customers		100.000%	91.170%	7.056%	1.631%	0.122%	0.021%	
11	Customer Component		56.152%	51.194%	3.962%	0.916%	0.069%	0.012%	
12	Design Day Volumes (excl MDS)		324,811	163,100	31,551	53,275	39,196	37,689	
13	Percent Design Day Volumes		100.000%	50.214%	9.714%	16.402%	12.067%	11.603%	
14	Demand Component		43.848%	22.018%	4.259%	7.192%	5.291%	5.088%	
15	Minimum System Allocation Factor		100.000%	73.211%	8.221%	8.108%	5.360%	5.100%	
16	**Allocation of Regulated Pressure Only Pipe**		$437,093,802.03	$320,000,743.41	$35,933,481.46	$35,439,565.47	23,428,227.79	22,291,783.90	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 20
FOR THE TWELVE MONTHS ENDED NOVEMBER 30, 2015

ALLOCATED COST OF SERVICE
CUSTOMER/DEMAND

WITNESS: M. BALMERT

Line No.	Description	Alloc	Total Company	RS/RDS	SGS1/SCD1/SGDS1	SGS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MDS
1	**Allocation of Remaining Regulated Pressure Pipe**								
2			Footage	Amount	Unit Cost				
3	2" Pipe		309,726	4,160,395.72	$13.43				
4	All Pipe		5,991,805	195,480,163.44					
5	Unit Cost of 2" x All Pipe Footage			80,469,941.15					
6	Customer Component			41.165%					
7	Demand Component			58.835%					
8	Allocable Remaining Regulated Pressure Pipe		$195,480,163.44						
9	Number of Customers (Total Company excl MDS)		420,393	383,005	30,676	6,079	539	94	
10	Percent Customers		100.000%	91.107%	7.297%	1.446%	0.128%	0.022%	
11	Customer Component		41.165%	37.504%	3.004%	0.595%	0.053%	0.009%	
12	Design Day Volumes (Total Company excl MDS)		769,993	441,900	82,752	109,891	63,707	71,743	
13	Percent Design Day Volumes		100.000%	57.390%	10.747%	14.272%	8.274%	9.317%	
14	Demand Component		58.835%	33.765%	6.323%	8.397%	4.868%	5.482%	
15	Minimum System Allocation Factor		100.000%	71.269%	9.327%	8.992%	4.921%	5.491%	
16	**Alloc. of Remaining Regulated Pressure Pipe**		$195,480,163.44	$139,316,757.69	$18,232,434.84	$17,577,576.30	9,619,578.84	10,733,815.77	
17	**Total Minimum System Allocation Factor**		$861,935,226.40	$649,806,880.72	$77,404,443.19	$65,942,067.36	34,639,656.92	34,142,178.21	
			100.000%	75.390%	8.980%	7.650%	4.019%	3.961%	

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 21
HOUSE REGULATORS

All Customers (less Low Pressure and Direct Assignment MDS)

LINE NO.	Rate	RS/RTS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MDS	TOTAL
1	RCC	82,260	0	0	0	0	0	82,260
2	RGC	4	0	0	0	0	0	4
3	RGS	13	0	0	0	0	0	13
4	RS	1,969,486	0	0	0	0	0	1,969,486
5	RTC	544,401	0	0	0	0	0	544,401
6	LG1	0	0	0	596	0	0	596
7	LG2	0	0	0	360	0	0	360
8	LG3	0	0	0	0	24	0	24
9	NSI	0	0	0	0	0	0	0
10	SGS	0	156,107	0	0	0	0	156,107
11	SG2	0	0	29,932	0	0	0	29,932
12	SG3	0	222	0	0	0	0	222
13	SG4	0	0	438	0	0	0	438
14	TAG1	0	600	0	0	0	0	600
15	TAG2	0	0	2,760	0	0	0	2,760
16	TAG5	0	5,198	0	0	0	0	5,198
17	TAG6	0	0	13,328	0	0	0	13,328
18	TIB	0	0	0	2,768	0	0	2,768
19	TIF	0	0	0	0	324	0	324
20	TIF-EFACT	0	0	0	0	12	0	12
21	TIG	0	0	0	0	48	0	48
22	TIH	0	0	0	0	12	0	12
23	TI4	0	0	0	2,376	0	0	2,376
24	TI8	0	0	0	0	492	0	492
25	TMA	0	0	0	0	0	0	0
25	TM2	0	0	0	0	0	0	0
26	TM3	0	0	0	0	0	0	0
27	801	0	0	0	12	0	0	12
28	802	0	0	0	0	0	0	0
29	803	0	0	0	0	12	0	12
30	806	0	0	0	12	0	0	12
31	808	0	0	0	0	12	0	12
32	809	0	0	0	0	24	0	24
33	810	0	0	0	0	12	0	12
34	816	0	0	0	0	12	0	12
35	819	0	0	0	0	12	0	12
36	820	0	0	0	0	12	0	12
37	821	0	0	0	0	0	0	0
38	830	0	0	0	0	12	0	12
39	831	0	0	0	0	0	0	0
40	833	0	0	0	0	12	0	12
41	838	0	0	0	12	0	0	12
42	840	0	0	0	0	12	0	12
43	841	0	0	12	0	0	0	12
44	845	0	0	0	0	12	0	12
45	846	0	0	0	0	12	0	12
46	847	0	0	0	12	0	0	12
47	848	0	0	0	0	0	0	0
48	850	0	0	0	0	0	0	0
49	856	0	0	0	12	0	0	12
50	857	0	0	12	0	0	0	12
51	858	0	0	0	12	0	0	12
52	859	0	0	0	0	12	0	12
53	860	0	0	12	0	0	0	12
54	861	0	0	0	12	0	0	12
55	862	0	12	0	0	0	0	12

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 21
HOUSE REGULATORS

All Customers (less Low Pressure and Direct Assignment MDS)

LINE NO.	Rate	RS/RTS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGS	LDS/LGS	MDS	TOTAL
56	863	0	0	12	0	0	0	12
57	864	0	12	0	0	0	0	12
58	865	0	0	0	12	0	0	12
59	866	0	0	0	0	0	0	0
60	868	0	0	0	0	12	0	12
61	872	0	0	0	0	0	0	0
62	873	0	0	0	0	12	0	12
63	874	0	0	0	12	0	0	12
64	875	0	0	0	0	12	0	12
65	876	0	0	0	12	0	0	12
66	877	0	0	12	0	0	0	12
67	878	0	0	0	0	0	0	0
68	879	0	0	0	12	0	0	12
69	SCC	0	46,693	0	0	0	0	46,693
70	SC2	0	0	6,841	0	0	0	6,841
71	**Total**	**2,596,164**	**208,844**	**53,359**	**6,232**	**1,116**	**0**	**2,865,715**
72	**ALLOCATOR #21**	90.594%	7.288%	1.862%	0.217%	0.039%	0.000%	100.000%

EXHIBIT MPB-2
ALLOC 22

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 22
AVERAGE ALLOCATORS 5 & 20

LINE NO.		RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	TOTAL
1	ALLOCATOR #5	490,756,975	82,247,065	112,843,196	64,088,809	111,999,181	861,935,226
2	ALLOCATOR #20	649,806,881	77,404,443	65,942,067	34,639,657	34,142,178	861,935,226
3	TOTAL OF BOTH STUDIES	1,140,563,856	159,651,508	178,785,263	98,728,466	146,141,360	1,723,870,453
4	AVERAGE OF BOTH STUDIES	570,281,928	79,825,754	89,392,632	49,364,233	73,070,680	861,935,226
5	**ALLOCATOR #22**	66.163%	9.261%	10.371%	5.727%	8.478%	100.000%

EXHIBIT MPB-2
ALLOC 23

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 23
METERS AND HOUSE REGULATORS - ACCOUNTS 381, 382, 383, & 384

LINE NO.	ACCT. NO.	ACCOUNT	TOTAL	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	381.00	METERS	37,714,590	28,095,484	1,518,767	7,606,656	380,540	107,109	6,034
2	381.10	AUTOMATIC METER READIN	24,289,208	18,094,246	978,126	4,898,890	245,078	68,981	3,886
3	382.00	METER INSTALLATIONS	37,776,149	28,141,342	1,521,246	7,619,071	381,161	107,284	6,044
4	383.00	HOUSE REGULATORS	12,047,377	10,914,201	878,013	224,322	26,143	4,699	-
5	384.00	HOUSE REG INSTALLATION!	3,864,772	3,501,252	281,665	71,962	8,387	1,507	-
6		TOTAL	115,692,095	88,746,523	5,177,816	20,420,902	1,041,309	289,581	15,965
7		ALLOCATOR #23	100.000%	76.709%	4.476%	17.651%	0.900%	0.250%	0.014%

COLUMBIA GAS OF PENNSYLVANIA, INC.
DEVELOPMENT OF ALLOCATION FACTOR 24
LABOR

LINE NO.	ACCT. NO.	ACCOUNT	ALLOC FACTOR	TOTAL COMPANY	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	816.00	WELLS	25	-	-	-	-	-	-	-
2	817.00	LINES	25	-	-	-	-	-	-	-
3	818.00	COMPRESSOR STATION	25	-	-	-	-	-	-	-
4	820.00	M & R	25	-	-	-	-	-	-	-
5	821.00	PURIFICATION	25	-	-	-	-	-	-	-
6	832.00	WELLS	25	-	-	-	-	-	-	-
7	834.00	COMPRESSOR STATION	25	-	-	-	-	-	-	-
8	836.00	PURIFICATION	25	-	-	-	-	-	-	-
9	870.00	SUPERVISION & ENGINEERING	18	2,309,279	1,834,583	188,530	149,780	69,925	66,069	393
10	871.00	LOAD DISPATCHING	13	130,111	98,066	11,681	9,951	5,228	5,152	33
11	874.00	MAINS & SERVICES	14	5,832,450	4,623,675	499,841	356,071	178,123	173,574	1,167
12	875.00	M & R - GENERAL	13	205,862	155,160	18,482	15,744	8,272	8,152	52
13	876.00	M & R - INDUSTRIAL	17	170,967	-	6,852	31,496	70,630	61,989	-
14	878.00	METERS & HOUSE REGULATORS	23	1,596,754	1,224,854	71,471	281,843	14,371	3,992	224
15	879.00	CUSTOMER INSTALLATIONS	15	3,761,222	3,415,453	277,052	58,261	7,786	2,671	-
16	880.00	OTHER	18	3,241,692	2,575,330	264,652	210,256	98,158	92,745	551
17	885.00	SUPERVISION & ENGINEERING	18	42,101	33,447	3,437	2,731	1,275	1,205	7
18	886.00	STRUCTURES AND IMPROVEMENTS	13	17,746	13,376	1,593	1,357	713	703	4
19	887.00	MAINS	13	4,141,763	3,121,689	371,848	316,762	166,416	164,014	1,035
20	889.00	M & R - GENERAL	13	328,773	247,800	29,517	25,145	13,210	13,019	82
21	890.00	M & R - INDUSTRIAL	17	55,076	-	2,208	10,146	22,753	19,970	-
22	892.00	SERVICES	15	1,417,757	1,287,423	104,432	21,961	2,935	1,007	-
23	893.00	METERS & HOUSE REGULATORS	23	54,680	41,945	2,448	9,652	492	137	8
24	894.00	OTHER EQUIPMENT	18	435,647	346,096	35,566	28,256	13,191	12,464	74
25	902.00	METER READING	6	345,736	315,221	25,104	4,892	436	76	7
26	903.00	CUSTOMER RECORDS AND COLLECTION EXPENSE	6	918,419	837,359	66,686	12,996	1,157	202	18
25	920.00	SALARIES	19	2,391,871	1,949,016	192,187	135,595	59,534	55,133	407
26	921.00	OFFICE SUPPLIES & EXPENSES	19	-	-	-	-	-	-	-
27	923.00	OUTSIDE SERVICES EMPLOYED	19	16,616	13,540	1,335	942	414	383	3
28		TOTAL		27,414,523	22,134,030	2,174,921	1,683,837	735,018	682,654	4,063
29		**ALLOCATOR #24**		100.000%	80.739%	7.933%	6.142%	2.681%	2.490%	0.015%

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

GROSS INTANGIBLE & DISTRIBUTION PLANT - GENERAL LEDGERS 101, 106 AND 107 – PAGE 3

INTANGIBLE PLANT - PAGE 3 (101-106-107)

Accounts 301, 302 and 303

Intangible plant was allocated on the basis of Distribution plant excluding Accounts 375.7, 375.71 and 387, Factor No. 11, due to its indirect relationship with all other plant.

UNDERGROUND STORAGE PLANT - PAGE 3 (101-106-107)

Accounts 350 through 355

Underground Storage Plant was allocated using Factor No. 25 – Sales and CHOICE Transportation activity for the historic test year reflecting its peaking support for sales and CHOICE customers.

DISTRIBUTION PLANT - PAGE 3 (101-106-107)

Account 375.60

Structures for large customers, not directly assigned, were allocated using Factor No. 17 since these structures house measuring and regulating stations serving the larger customer groups only.

Account 376 – Mains

Non-directly assigned mains were allocated by rate schedule based on the weighting of design day and annual throughput, Factor No. 5, for the peak and average study. For the Customer-Demand study such investment was based on Factor No. 20 which provides a customer component based on a 2" "Minimum System" with the remaining portion assigned on design-day. For the Average study, Factor No. 5 and Factor No. 20 are averaged to assign the Mains costs to the various rate schedules. Please see Exhibit MPB-1 for a detailed description of Factor Nos. 5 & 20.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Direct Mains

Mains for Main Line Delivery Service ("MDS") were identified by reviewing the Company's maps and accounting records and directly assigned to this class. Due to the unique characteristics of these customers, i.e., proximity to an interstate pipeline company and minimal Company investment, the investment was directly assigned.

Mains - Related Accts

Accounts related to/or supports the mains gas plant account were allocation on Factor No. 5 under the Peak and Average study, Factor No. 20 under the Customer-Demand study, and Factor No. 22 under the Average study since these accounts directly support the mains investment. The mains-related accounts generally include the follow gas plant accounts: 374.10, 374.20, 374.30, 374.40, 374.41, 374.50, 375.20, 375.31, 375.40, 375.80, 378.10, 378.20, 378.30, 379.10 and 379.11.

Direct Mains - Related Accts

Similarly to the mains - related accounts above, these are accounts that support the mains that were directly assigned to MDS and include accounts 374.40, 374.50, 375.40, and 378.20. Like direct – mains, the amounts were identified from the company's maps and accounting records and directly assigned.

Account 380 - Services

Account 380 - Services was assigned by rate schedule based on each customer's service size and the average unit cost of that size service on the company's plant accounting records. This methodology represents virtually a direct assignment of costs to the various rate classes.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Like mains, services for MDS were identified by reviewing the Company's maps and accounting records and directly assigned to this class. Due to the unique characteristics of these customers, i.e., proximity to an interstate pipeline company and minimal Company investment, the investment was directly assigned.

Accounts 381 and 382

Meters and Meter Installations were allocated using Factor No. 16 which was based on an actual inventory of meters installed on customer premises as explained in Statement 11. This methodology represents virtually a direct assignment of costs to the various rate classes.

Accounts 383 and 384

House Regulators and House Regulator Installations were allocated using Factor No. 21 which was based on an actual inventory of house regulators installed on customer premises as explained in Statement No. 11. This methodology represents virtually a direct assignment of costs to the various customer groups

Account 385

Industrial Measuring and Regulating Stations were allocated using Factor No. 17 which was based on a review of Columbia's records as explained in Statement 11. Measuring stations were segregated by rate schedule by identifying measuring stations in the plant accounting records with the individual customers in the DIS billing system. This methodology represents virtually a direct assignment of costs to the various rate classes.

Dist Plant Excl Other Allocated

This investment consists of gas plant accounts 375.70, 375.71 and all 387 and was allocated to the various rate schedules using Factor No. 11. Factor No. 11 was based on distribution plant specifically assigned and was used to assign general investment and costs that support the distribution system.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

General Plant

General plant includes items such as general tools (cars, trucks, backhoes, etc), communication equipment, office furniture and fixtures, and other miscellaneous equipment. Like general distribution plant, this plant investment supports the delivery of natural gas and therefore Factor No. 11 was used to assign the investment.

RESERVE FOR DEPRECIATION - PAGE 4

Depreciation Reserve was calculated on an account by account basis using the same allocation factors that were used to allocate all gross plant accounts

DEPRECIATION & AMORTIZATION EXPENSE and NET NEGATIVE SALVAGE - PAGE 5

Depreciation and amortization expense was allocated by gas plant account on the same allocations as the Gross Original Cost. Amortization of net negative salvage was allocated using Factor 11 based on its remediation of distribution type facilities.

OPERATING REVENUE AT CURRENT AND PROPOSED RATES - PAGE 6

Sales and Transportation Revenue

Sales and transportation revenue was directly assigned as presented in Exhibit No. 103 for the fully forecasted rate year and supported by Witness Melissa Bell.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Accounts 487

Forfeited discounts were allocated using Factor No. 10 which was developed from actual forfeited discounts billed by rate class during the historic test year twelve months ended November 30, 2015.

Accounts 488, 493 and 495

Miscellaneous Revenue and Other revenue were allocated using Factor No. 6 - Average Number of Customers since costs incurred throughout these accounts are directly related to the customers served. Rent Revenue was allocated using Factor No. 11 because the rent is derived mostly from the rent of company-owned office buildings, making the use of the Distribution Plant allocator appropriate.

OPERATING EXPENSES – PURCHASED GAS EXPENSES - PAGE 7

Gas purchased cost

These costs were directly assigned based on revenue for the fully forecasted rate year as presented in Exhibit No. 103.

Account 807

Gas Purchase Expense and Gas Procurement Expenses were allocated using Factor No. 4 which is based on the direct assignment of gas costs. Factor No. 4 was used reflecting the relationship of these costs to gas purchase costs. Gas purchase expense related to the gas procurement activity was also allocated using Factor No. 4.

OPERATING EXPENSES – UNDER STORAGE EXPENSES - PAGE 7

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Accounts 814 through 837

Underground Storage Plant Expense was allocated using Factor No. 25 – Sales and CHOICE Transportation.

DISTRIBUTION EXPENSES – OPERATIONS - PAGE 7

Accounts 870, 880, 881

General costs for supervision and engineering, rents and other items of the distribution function were allocated using Factor No. 18, Other Distribution Expense, since these costs benefit customers in the way that all other distribution costs provide benefit.

Account 871

Distribution Load Dispatch Expenses were allocated on Factor No. 13 – Direct Plant – Mains since these are costs incurred monitoring and directing the flow of gas through the distribution system.

Account 874

Mains and Services Operation Expenses (a dual function account) were allocated on Factor No. 14 – Composite Direct Plant - Mains and Services combined.

Accounts 875

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures since these costs are incurred in direct relation with mains.

Accounts 876

Expenses for Measurement and Regulator Station Equipment - Industrial were allocated using Factor No. 17 – Direct Assignment – IND M&R - since these costs are incurred in direct association with the stations in Account 385.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Accounts 878 and 879

Meters & House Regulators Expenses were allocated using Factor No. 23 which was based on an actual inventory of meters and house regulators installed on customer premises as explained in Statement No. 11. This methodology represents virtually a direct assignment of costs to the various rate classes. Expenses for Customer Installations were allocated using Factor No. 15 because these expenses are related to the customer service lines.

DISTRIBUTION EXPENSES – MAINTENANCE - PAGE 7

Accounts 885 and 894

General costs for supervision and engineering and maintenance costs of other equipment of the distribution function were allocated using Factor No. 18 other distribution expense since these costs benefit customers in the same way that all other distribution costs provide benefit.

Account 886

Structures and Improvements Expense was allocated using Factor No. 13, reflecting the spread of Account 376 Mains among all customer classes, because these plant and expense functions are directly related.

Account 887

Mains Maintenance Expense was allocated using Factor No. 13, which reflects the spread of Account 376 Mains among all customer classes, since plant and expense functions are directly related.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Accounts 889

Factor No. 13 was used to allocate expenses for distribution load dispatch, general measurement and regulator stations and related structures since these costs are incurred in direct relation with mains.

Accounts 890

Expenses for Measurement and Regulator Station Equipment - Industrial were allocated using Factor No. 17 - Direct Assignment – IND M&R - since these costs are incurred in direct relation with the stations in Account 385.

Account 892

Expenses for Services were allocated using Factor No. 15 which was based on size of service and size of customer as explain above under Gas Plant Account 380 – Services and in Statement No. 11.

Account 893

Meters & House Regulators Expenses and Customer Installations were allocated using Factor No. 23 which was based on a weighted average cost of meters and house regulators as explained in Statement No. 11.

CUSTOMER ACCOUNTS, CUSTOMER SERVICE AND INFORMATIONAL AND SALES EXPENSES - PAGE 8

Account 904 – Uncollectibles – DIS Revenue & Uncollectibles GMB/GTS Revenue

These cost categories represent traditional bad debts. They have been separated between the residential and commercial classes of customers and allocated based on the historical charge-offs and revenue, related to each, as included in Factor No. 7 for DIS and Factor No. 8 for GMB/GTS, respectively.

Account 904 Uncollectibles – Unbundled

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

These costs were directly assigned to each rate schedule matching revenue for the fully forecasted rate year as presented in Exhibit No. 103 for the Merchant Function Charge.

Account 904 – Direct USP Uncollectibles

These uncollectibles are directly related to the Company's Customer Assistance Program ("CAP") available to residential customers and are recoverable from the residential class whether sales or delivery service. The amounts shown are reflected in revenue for the fully forecasted rate year as presented in Exhibit No. 103.

Customer Accounts

Customer Accounts includes meter reading, customer records, and credit and collection activities recorded in accounts 901 through 903, 905, and 921. These costs were allocated using Factor No. 6, Average Number of Customers, since they are directly related to the number of customers served. Interest on Customer Deposits was allocated using Factor No. 9 because the interest is directly related to the amount of customer deposits.

Customer Service Information

Customer Service and Informational Costs are reflected in accounts 907 through 910 plus related costs in 921 and 931. These costs were allocated using Factor No. 6 since all customers may benefit except account 908 – Direct USP/LIURP/HEEP. These costs include the recovery of specific customer programs benefiting residential customers. The amounts reflect the recovery included in revenue as presented in Exhibit No. 103 for the fully forecasted rate year.

Sales Expense

Sales expenses, accounts 912 and 913, were allocated using Factor No. 6, Average Number of Customers, since these activities directly support customers served.

<u>ADMINISTRATIVE AND GENERAL EXPENSES - PAGE 8</u>

Admin. & General Expenses (Line 33)

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

General Office Expenses, and to a lesser degree, District and Local Office Expenses in this function classification, plus company-wide expenses excluding Employee Benefits, account 926, such as Injuries and Damages, Insurance, and Regulatory Commission Expense were all allocated using Factor No. 19 - Total Operation & Maintenance Excluding Gas Purchased, A & G, Uncollectibles and USP rider costs. These costs are regarded as overhead to the entire company operation and, therefore, follow the allocation of the aggregate of all other previously allocated O&M costs. Employee Pensions & Benefits, account 926, was allocated on Factor No. 24, Labor, since they are directly related to company labor. Account 923 – Multifamily House Line Reimbursement costs are a proposed residential program and therefore the costs are directly assigned to the residential class.

TAXES OTHER THAN INCOME - PAGE 9

Property taxes are directly related to tangible property and, accordingly, have been allocated based on Factor No. 11 - Distribution Plant excluding Other due to a direct relationship with Plant in Service. Similarly, PA Capital Stock and License and Franchise Taxes were allocated using Factor No. 11 as they are also related to Plant in Service. Federal Unemployment Insurance, State Unemployment Insurance and F.I.C.A. (payroll based taxes) are all labor-related and, accordingly, have been allocated based on Factor No. 24 – Labor. State Sales and Use Tax and Other Taxes were allocated using Factor 19 since these taxes are generally related to the purchase of supplies.

RATE BASE SUMMARY - PAGE 10

Account 154

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

Materials and Supplies were allocated based on Factor 11, Distribution Plant Excluding Other, reflecting the primary future use of such inventory.

Account 164 & 117

Gas Stored Underground, both current and long term, was allocated based on Factor No. 25, Sales and CHOICE Transportation, reflecting the support of these customers in meeting their design day and seasonal requirements.

Account 165

Prepayments consist primarily of commission fees and corporate insurance therefore they were allocated using Factor 19,Total O&M Excluding Gas Purchased Costs, A&G, Uncollectibles, and USP Rider Costs.

Accounts 190, 282 and 283

All deferred income taxes included in rate base are plant related therefore, Factor No. 12, Gross Plant, was used.

Account 235

Customer Deposits were allocated using Factor 9, Direct Assignment – Customer Deposits.

Accounts 252 and 186

Customer advances, other deferred credit and materials and supplies were allocated using Factor No. 11 - Distribution Plant Excluding Other, due to their direct relationship with all other gas plant accounts.

COLUMBIA GAS OF PENNSYLVANIA, INC.
FACTOR SELECTION AND RATIONALE

FEDERAL AND STATE INCOME TAX - PAGE 11

All of the Company's tax adjustment over book are plant related, i.e., tax depreciation over book depreciation and, therefore, the tax deductions were allocated using Factor No. 12, Gross Plant.

In calculating the Federal and State income taxes for each rate schedule, the effective Federal and State income tax rates were used. Income taxes were calculated for each rate class.

Columbia Gas of Pennslyvania, Inc.
Intra Class Adjustment from SGDS to SGSS and SCD at Proposed ROE of 11.00%
For the 12 Months Ending December 31, 2017

Ln. No.	Item	Total	RSS/RDS	SGSS1/SCD1/SGDS1	SGSS2/SCD2/SGDS2	SDS/LGSS	LDS/LGSS	MLDS
1	Account 117	3,794,693	2,781,851	462,004	468,075	71,568	5,920	5,275
2	Account 164	48,336,766	35,435,200	5,885,001	5,962,340	911,631	75,405	67,188
3	Allocated Storage Per ACOS Study using Allocation Factor #25	52,131,459	38,217,051	6,347,005	6,430,415	983,199	81,325	72,463
4	Sales & CHOICE Transportation (Dth)	46,929,034.0	34,403,669.0	5,713,732.0	5,788,507.0	884,981.0	73,145.0	65,000.0
5	Factor 25 Allocation of Storage	100%	73.309%	12.175%	12.335%	1.886%	0.156%	0.139%
6	Pre-Tax as Filed	12.23%	12.23%	12.23%	12.23%	12.23%	12.23%	12.23%
7	Revenue Requirement related to storage assigned to rate schedule (Ln. 6 * Ln. 7)	6,375,677	4,673,945	776,239	786,440	120,245	9,946	8,862
8	Rate Per Dth	0.1359						

Ln. No.	Item	Total DTH	% of Total	Included In Proposed Rates	Ratio	Redistributed Per Settlement
9						
10						
11						
12						
13	SGSS1 - Subject to Storage	4,337,145.0	73.860%	573,330	0.7591	15,909
14	SCD1 - Subject to Storage	1,376,587.0	23.440%	181,950	0.2409	5,049
15	SGDS1 - Not Subject to Storage	158,613.0	2.700%	20,958		(20,958)
		5,872,345.0	100.000%	776,239		0

Ln. No.	Item	Total DTH	% of Total	Included In Proposed Rates	Ratio	Redistributed Per Settlement
16						
17						
18						
19						
20	SGSS2 - Subject to Storage	4,765,071.0	52.470%	412,645	0.8232	234,746
21	SCD2 - Subject to Storage	1,023,437.0	11.270%	88,632	0.1768	50,417
22	SGDS2 - Not Subject to Storage	3,293,047.0	36.260%	285,163		(285,163)
		9,081,555.0	100.000%	786,440		0

COLUMBIA STATEMENT NO. 12

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
vs.	)	Docket No. R-2016-2529660
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
SHIRLEY BARDES HASSON
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

I. <u>Introduction</u>

Q. Please state your name and business address.

A. Shirley Bardes Hasson, 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

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, Regulatory Policy.

Q. What are your responsibilities as Manager, Regulatory Policy?

A. I am responsible for managing regulatory activity before the Pennsylvania Public Utility Commission ("Commission"). This responsibility includes ensuring timely, accurate regulatory filings before the Commission, overseeing and/or administering tariff changes and filings, as well as compliance with Columbia's Rates and Rules for Furnishing Gas Service, known as Tariff Gas Pa. P.U.C. No. 9 ("tariff"), and regulations affecting Natural Gas Distribution Companies ("NGDC") within this Commonwealth. I also monitor cases before the Commission, recommend Company participation and develop comments for filing when warranted.

Q. What is your professional experience with the Company?

A. I have been an employee of Columbia since 1987 when I accepted a position in the Company's customer service department. In 1989, I was promoted to Office Operations Training Instructor where I provided customer service and compliance training to telephone representatives and field service technicians. My customer service and training experience required comprehensive knowledge of Chapter 56 of the Commission's regulations and Columbia's tariff. From 1995 until 2003, I held various positions working with the CHOICE®[1] program ("Choice Program" or "Choice") and large commercial and industrial transportation, initially as a Distribution Gas Transportation Coordinator, and progressing to Manager, Gas Transportation in 2001. I was significantly involved in the original development, expansion, and modification of the Columbia Choice Program. I supervised employees who provided billing, collections and customer service to Columbia's largest commercial and industrial distribution service customers, and I acted as liaison between the Natural Gas Suppliers ("NGS") and the Company. In 2004, I joined the Regulatory Department as Manager, Regulatory Policy.

Q. Have you testified before this or any other Commission?

A. Yes, I have provided testimony before this Commission in several formal customer complaint cases and in Columbia's last five base rate cases at Docket Nos. R-2009-2149262, R-2010-2215623, R-2012-2321748, R-2014-2406274 and R-2015-2468056. I have also testified before the Maryland Public Service Commission on several occasions.

Q. What exhibits are you sponsoring?

A. I am sponsoring Exhibit 014, Schedule 1 – the list of reports, data or statements requested by and submitted to the Commission, submitted in compliance with Section 53.53 III. A. 26, and Exhibits 14, Schedule 2 and Exhibit 114, Schedule 1,

[1] Customer CHOICE℠ is a service mark of Columbia Gas of Ohio, Inc. and its use has been licensed by Columbia Gas of Pennsylvania, Inc. CHOICE® is a registered mark of Columbia Gas of Ohio, Inc. and its use has also been licensed by Columbia Gas of Pennsylvania, Inc.

which are copies of the currently effective tariff, and the Company's proposed changes to those tariff pages.

Q. Please explain the scope of your testimony.

A. I will review the tariff revisions proposed in Tariff Supplement No. 241 and provide detail behind substantive revisions.

II. <u>Tariff Changes Summary</u>

Q. Please provide a brief description of Columbia's proposed tariff changes.

A. The non-substantive tariff changes include formatting changes, such as renumbering where applicable, labeling, and moving existing text to another page.

Q. What are the substantive tariff changes?

A. The substantive tariff changes include the following changes to tariff sections in the Rules and Regulations Governing the Distribution and Sale of Gas:

- The Rate Summary, Rider Summary, Gas Supply Charge Summary, Pass-through Charge Summary and the Price-to Compare Summary;
- "1.6 Definitions";
- Rule 2. Service Limitations;
- Rule 8. Extensions;
- Rate Schedules Small Distribution Service ("SDS"), Large General Sales Service ("LGSS"), Large Distribution Service ("LDS"), Main Line Sales Service ("MLSS"), Main Line Distribution Service ("MLDS") and Natural Gas Vehicle ("NGV"); and 6.) Rider Elective Balancing Service ("EBS").

Other substantive changes include:

- "Rule 1. Definitions" in the Rules Applicable to Distribution Service ("RADS") has a new definition.
- Areas revised in the Rules Applicable to All Distribution Service ("Rule 2") of the RADS are: 1) Section 2.4 NGS Creditworthiness; and 2) Section 2.7 Distribution Nominations.
- The Rules Applicable Only to General Distribution Service ("Rule 3") reflect changes to: 1) 3.7 Operational Flow Orders ("OFO"); and 2) 3.8 Operational Matching Orders ("OMO");
- The Rules Applicable Only to Choice Service ("Rule 4") has changes in: 1) 4.6 Enrollment Procedures; 2) 4.7 Choice Aggregation Service; 3) 4.9 Gas Supply Requirements; 4) 4.13 Company Billing of NGS Natural Gas Supply Services; and 5) 4.16 Termination of an NGS's Participation Under This Schedule.
- Revisions to the interstate transmission pipeline names;
- Three edits that are a result of one statute change and two Commission orders in previous proceedings. In those instances the edits were not included in the associated compliance tariff filing.

Q. Is there a listing of all the tariff changes available?

A. Yes, Tariff pages 2 through 2e present the List of Changes proposed to the Tariff in this base rate case.

III. Non-Substantive Tariff Changes

Q. Begin by describing the formatting changes.

A. The Definitions on pages 26, 27, 28, 29, 184, 185, new page 185a, and 186 have been renumbered and several existing definitions have been shifted to subsequent pages. There are also numbering and labeling edits in the Table of Contents on page 3. The definition for "month" on page 183 in the currently effective tariff is moved to page 184. These changes are the result of the addition of a new definition, which I will discuss under the substantive changes section of my testimony. Renumbering also occurs on pages 49 and new page 49a. Page shifting for existing text occurs on pages 26, 27, 28, 29, 49, new page 49a, 50, 112, 113, 184, 185, new page 185a, 186, 187, new page 187a, 201 and 202.

Q. Describe the name change to the interstate pipelines.

A. A few years ago, Columbia Gas Transmission Corporation and Columbia Gulf Transmission Company became Columbia Gas Transmission, LLC and Columbia Gulf Transmission, LLC. These name changes are reflected throughout the tariff. On page 27 "DTI" has been changed to "Dominion".

IV. Substantive Tariff Changes

Q. What text in the Tariff needs updated to coincide with previously approved filings?

A. First, the definition of Residential Customer on page 27 has been revised to comply with Act 54 and 66 Pa. C.S. § 1529.1. The change removes the portion of the definition that reflects a tenant having the gas service account in their name when there are other tenants receiving gas service from the same account.

Q. What is the second instance?

A. The second instance affects the Rider State Tax Adjustment Surcharge on page 165. In the first paragraph there is a phrase "for service rendered on and after January 1, 2014." The date in that phrase was not updated to "December 20, 2014" in the Tariff Compliance Filing that was effective December 20, 2014, in Docket No. R-2014-2406274.

Q. What is the reasoning for removing the phrase that includes the date in the first paragraph on page 165?

A. Since the effective date for the contents of the Tariff page appears in the lower right hand corner of the page, including the date in the first paragraph is duplicative, and therefore, unnecessary.

Q. Explain the third instance.

A. Page 171 deletes "ninety percent (90%) of the index". This text relates to a cash out of imbalance gas when a Customer Proxy is no longer active on Columbia's system and has gas remaining in storage. Columbia allows the Customer Proxy one month to sell the gas to another General Distribution Service ("GDS") customer or Natural Gas Supplier ("NGS"). If there is still gas remaining on the customer's account after a month of inactivity, Columbia purchases any remaining gas. In the Commission-approved Settlement (Docket No. R-2015-2468056), the cash out rate for Deliveries in Excess of Consumption was revised making the reference on page 171 inaccurate.

The removal of the "ninety percent (90%) of the index" phrase on page 171 corrects the reference to the Deliveries in Excess of Consumption rate calculation.

Q. What changes are reflected on the Rate Summary?

A. The Rate Summary pages 16, 17 and 18 reflect increases to the Customer Charge, Distribution Charge and Pass-through Charge, with one exception. The Customer Charge does not change for annual throughput less than or equal to 6,440 therms on Rate Schedules Small General Sales Service ("SGSS"), Small Commercial Distribution ("SCD") and Small General Distribution Service ("SGDS"). The Gas Supply Charge billed to Rate Schedules Residential Sales Service ("RSS") and SGSS has decreased.

Page 20, the Other Rates Summary, reflects a decrease in the Price-to-Compare.

Q. Explain the changes on the remaining "Summary" pages.

A. The Rider Summary on page 21 and the Pass-through Charge Summary on page 21b reflect an increase in the Rider USP – Universal Service Plan.

A decrease to the Rider MFC – Merchant Function Charge is reflected in the Rider Summary on page 21, the Gas Supply Charge Summary on page 21a and the Price-to-Compare Summary on page 21c.

Q. Where did these rate changes originate?

Each of these rate changes were obtained from Exhibit No. 103, Schedule No. 8 pages 6 through 10. The rate design is discussed in Statement No. 3, which is in Company witness Bell's testimony.

Q. What is changing in the Definition sections of the Tariff?

A. A definition for Maximum Daily Quantity, or "MDQ" has been inserted in section 1.6 on page 26, which is located in the Rules and Regulations Governing the Distribution and Sale of Gas and page 184 in Rule 1 Definitions of the RADS. The definition adds a new process of establishing a summer and winter MDQ. The summer MDQ will be based on the most recent historical usage from April through October, and the winter MDQ will be based on the most recent historical usage from November through March.

Q. What are current MDQs based on?

A. MDQs are currently based on winter usage for all GDS customers, except asphalt plants, grain dryers and power generators.

Q. What is the reasoning for establishing a summer and a winter MDQ?

A. While commercial customers generally experience their peak day usage during the cold winter months, that is not always true for industrial customers. Some industrial customers, like asphalt plants, grain dryers, and some power generators have their greatest usage during the summer.

Operational Flow Orders ("OFOs") are another reason for establishing seasonal MDQs. An OFO is a Company-issued order to Shippers who nominate gas to customer accounts that do not have daily gas measurement installed at their facility. The Company has the authority to issue an OFO whenever the Company believes that the daily safe and/or reliable operation of its distribution system may be jeopardized, including, without limitation, the need to protect the daily supply of Sales and Choice customers. When an OFO is issued, the required amount of gas to nominate is based on a percentage of a customer account's MDQ. By adding a summer MDQ, any OFOs that are in place during the April through October timeframe will ensure nominations more closely match the individual account usage. Therefore, using summer and winter MDQs provide customers and Customer Proxies with a more accurate representation of customer usage for these seasonal periods.

Q. Are there other tariff changes as a result of the newly defined term of "Maximum Daily Quantity" and the addition of a summer MDQ?

A. Yes. Where the defined term of "Maximum Daily Quantity" or "MDQ" is mentioned throughout the tariff, the words "currently effective" have been inserted preceding the term. In addition, Columbia proposes to remove the last sentence in paragraph 3.2.1 on page 201 that requires asphalt plants, grain dryers and power generators to provide an MDQ for January.

Q. What change is proposed for the Service Limitations section?

A. On Tariff page 32, the "Emergency Actions Curtailments" paragraph has been labeled 2.3.3. This labeling is appropriate since page 31 of the currently effective tariff reflects 2.3.2 Demonstration of Firm Pipeline Capacity and page 33 of the currently effective tariff reflects 2.3.4 Priority Based Curtailments.

Q. Explain the revisions to Rule 8. Extensions.

A. The word "dedicated" is deleted on page 48. By removing this single word, Columbia will have the ability to apply the Capital Expenditure Policy to privately owned roads where a residential applicant(s) resides.

Page 49 reflects a new paragraph entitled "Residential Multi-Unit Developer Reimbursement". This new paragraph provides an incentive to a builder or developer to individually meter each residential unit in a multi-unit structure by providing a reimbursement for costs associated with installing house lines and/or venting throughout the building, which enable the residents to receive gas service.

On new page 49a, the first sentence in paragraph 8.2.3 (b) has been grammatically revised to add clarity. Page 49a also reflects a new paragraph 8.2.5 Payment Period of Deposit. This paragraph allows a commercial or industrial applicant to enter into an installment agreement for payment of a deposit for a main line extension when the main line extension requires a contribution by the applicant.

For further detail regarding the new paragraphs on pages 49 and 49a, please see the testimony of Company witness Waruszewski, in Statement No. 13.

Q. Are additional changes required to the proposed changes to the Captial Expenditure Policy?

A. Yes. Specifically, changes are required do the new paragraph 8.2.5 Payment Period of Deposit previously discussed.

Rate Schedules SDS, LGSS, LDS, MLSS, MLDS and NGV have a new paragraph entitled "Main Line Extension Deposit Installment Plan". This paragraph specifies that any agreed upon installment amount will be added to the Customer Charge on the customer's bill for the duration of the installment payment plan.

Q. Explain the Rider EBS changes.

A. The change to page 167 provides the Company with the ability to offer a new GDS customer limited Option 1 service under Rider EBS when full service is not available. This could occur when the customer begins service on GDS after the EBS election period in August each year.

On page 168, repetitive text referring to the Rules Applicable Only to General Distribution Service of the RADS is removed to make the paragraph easier to understand.

Q. Explain the change to the RADS, Section 2.4 NGS Creditworthiness.

A. New tariff page 187a contains the existing text of paragraph 2.4.3 Amount and Form of Security that was moved from page 187 and new text listing the forms of security as specified in Title 52, §62.111 (c) (2) of the Pennsylvania Code.

Q. What change is made to RADS, Section 2.7 Distribution Nominations?

A. The revision to tariff page 191 adds new paragraph 2.7.2 under section 2.7 Distribution Nominations. Paragraph 2.7.2 identifies the actions Columbia may take in order to comply with upstream pipeline restrictions and maintain operational integrity.

Q. According to this new paragraph, what actions may Columbia take?

A. The Company may require a Shipper to schedule gas from multiple transmission pipeline delivery points. When pipeline restrictions or operational limitations limit deliveries to the Company's city gate, for example, the new paragraph clarifies the Company's ability to require deliveries at alternate delivery points. This provides

Customer Proxies with the ability to continue delivering their desired/required gas supplies at a location that is not impacted by the restriction.

Q. What changes are proposed for 3.7 Operational Flow Orders ("OFOs") and 3.8 Operational Matching Orders ("OMOs") of the RADS?

A. There is one substantial change proposed that is applicable to both sections 3.7 and 3.8. Specifically, paragraphs 3.7.3 and 3.8.4 further define that gas quantities contracted for under Rate Schedule Standby Service ("SS") may be used only when the OFO or OMO is addressing an under delivery situation.

Q. Please explain the reason for this change.

A. The Maximum Daily Firm Requirement under Rate Schedule SS is the MDQ of gas that a customer proposes to reserve for purchase from the Company. Under an OFO or OMO in an under delivery situation, the Customer may purchase gas from the Company up to its contracted standby service level to alleviate a portion of its shortfall. In an over delivery situation, the purchase of additional supplies from the Company under Rate Schedule SS does not make practical sense. Therefore, in order to determine compliance with the OFO or OMO, Rate Schedule SS should only be considered during an under delivery situation.

Q. Please explain the change to Section 4.6 Enrollment Procedures in the Rules Applicable Only to Choice Service.

A. Columbia is simply documenting the requirement of including the "enrollment type" when a NGS is submitting customer information for enrollment in Choice. This change is reflected in Paragraph 4.6.5.

Q. Is the "enrollment type" a new requirement in Columbia's enrollment procedure?

A. No. Columbia's Choice enrollment procedures have required the enrollment type for several years.

Q. What is the purpose for requiring the enrollment type?

A. The enrollment type identifies the way the NGS enrolled the customer in Choice. The three types of enrollment are by telephone, internet and in writing.

Q. What is changing in section 4.7 Choice Aggregation Service?

A. On page 233, in paragraph 4.7.4.2, there is a change to the reference for the index used to calculate the rate used for the Choice program annual cash out.

Q. Why is the reference to the index changing?

A. The reference to the index is changing because the publication, Platt's Inside FERC's Gas Market Report, changed the location and labeling of the Columbia Gas Transmission Appalachia price. The monthly price is now found under a column heading of "Index" for "Columbia Gas, App".

Q. What else is changing in section 4.7?

A. Paragraphs 4.7.4.1 and 4.7.4.3 have been revised to coincide with paragraph 4.7.4.2. The specific revision addresses the calculation of the cash-out rate used for the annual Choice Program reconciliation. Currently effective subparagraph 4.7.4.2 was revised with Supplement No. 225, which became effective April 1, 2015, in compliance with the Order of the Commission approving the Joint Petition for Settlement at Docket No. R-2012-2321748. Supplement No. 225 did not update paragraph 4.7.4.1. To correct the inconsistency, Columbia is removing the description of the cash out rate calculation from paragraph 4.7.4.1 and adding the correct cash out rate calculation description to paragraph 4.7.4.3. With this proposed change, Paragraph 4.7.4.2 and 4.7.4.3 will have identical cash out rate calculation descriptions.

Q. What is changing in section 4.9 Gas Supply Requirements?

A. Similar to new paragraph 2.7.2 on page 191, the new text in paragraph 4.9.5 states that the Company may require a Choice NGS to schedule gas from multiple transmission pipeline delivery points. When pipeline restrictions or operational limitations restrict deliveries to the Company's city gate for example, the new paragraph clarifies the Company's ability to require deliveries at alternate delivery points. This provides Choice NGSs with the ability to meet their Choice Daily Delivery Requirements utilizing an alternate point that is not impacted by the restriction.

Q. Please describe the revision to 4.13 Company Billing of NGS Natural Gas Supply Services.

A. Paragraph 4.13.3.2.1 includes a description of how and when an NGS shall provide its billing determinants to Columbia. The revision to this paragraph specifies the revised business day when the billing determinants are due if the normal due date falls on a weekend or holiday.

Q. What is Columbia proposing to change in section 4.16 Termination of an NGS's Participation Under This Schedule?

A. Columbia is proposing to remove "OMO" from paragraph 4.16.1.

Q. What is the reason for this change?

A. Section 4.16 falls under the Rules Applicable Only to Choice Service. OMO's are only applicable to customer accounts with daily measurement. On Columbia's system, Choice eligible customers do not have daily measurement. Therefore, OMO's are not applicable to Choice.

Q. Does this conclude your direct testimony?

A. Yes, it does.

COLUMBIA STATEMENT NO. 13

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
vs.	)	Docket No. R-2016-2529660
Columbia Gas of Pennsylvania, Inc.	)	

DIRECT TESTIMONY OF
ROBERT C. WARUSZEWSKI
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

I. Introduction

Q. Please state your name and business address.

A. Robert C. Waruszewski, 121 Champion Way, Suite 100, Canonsburg, Pennsylvania.

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 a Senior Regulatory Analyst.

Q. What are your responsibilities as Senior Regulatory Analyst?

A. I assist in the coordination and supervision of regulatory activity before the Pennsylvania Public Utility Commission ("Commission"), including rates and tariffs.

Q. What is your educational and professional background?

A. I graduated in 2011 from St. Vincent College, Latrobe, Pennsylvania where I majored in both mathematics and economics. After graduation, I worked as a junior accounting clerk for the Bank of New York Mellon, assisting in the preparation of audits as well as gathering local tax data for the bank's employees before joining Columbia in November of 2011 in the Regulatory Department. In November of 2013, I was promoted to my current role of Senior Regulatory Analyst.

Q. Have you testified before this or any other Commission?

A. Yes, I testified in the Company's 2015 Rate Case, R-2015-2468056 and in the Company's Snowshoe Abandonment Proceeding, A-2015-2513395. In addition, I have testified before the Public Service Commission of Maryland on several occasions.

Q. Please describe the scope of your testimony in this proceeding.

A. I am presenting and describing two new business proposals designed to expand the availability of natural gas service in Columbia's service territory. In addition, I am sponsoring Columbia's request to include transaction fees associated with all payment channel options available to residential customers in the cost of service.

Q. What new business proposals were approved in Columbia's 2015 Rate Case?

A. Columbia's proposals of a footage allowance of 150 feet of main per residential applicant, an allowance of 150 feet of service line in the areas where the Company owns the service line, and a reimbursement for up to $1,000 of house piping costs per applicant on qualifying projects were approved in the Company's last rate case.

Q. Please describe the Company's current line extension policy.

A. When a potential customer requests that Columbia extend its facilities to serve the potential customer, the Company uses an economic analysis to determine the cost of serving that customer, as described in section 8.2 of its tariff. This analysis compares the net present value ("NPV") of the projected future revenue, for that customer, to the cost to add the customer to Columbia's system. For residential customers, the Company will extend up to 150 feet of main, as well up to 150 feet of service line, in the areas where the Company owns the service line, per the programs approved in the Company's 2015 rate case without cost to the customer. If the project requires greater extensions for residential customers, the economic analysis is undertaken. If the result is positive, that is, the projected customer revenues are greater than or equal to the projected cost on a net present value basis, then the Company will make the line extension without cost to the customer. However if the result is negative, that is, projected costs are greater than projected revenues, the customer pays a deposit for service equal to the NPV difference. If Columbia is approached by multiple potential customers to be served off a single extension of facilities, projected revenues and costs are combined into a single calculation.

Q. Has the Company received encouragement to expand the availability of natural gas throughout Pennsylvania?

A. Yes, in her statement regarding Columbia's New Business Proposals approved in R-2015-2468056, Commissioner Witmer stated:

> I applaud the addition of these complementary proposals. When effectuated, they should enable more individuals to receive natural gas service and they serve as a positive step in removing barriers for customers that desire to convert to natural gas. I believe it is critically important to promote innovative programs to encourage the extension of natural gas to underserved and unserved areas of the Commonwealth. To that end, I appreciate the Company's responsiveness in creating more expansive opportunities for conversion, and I look forward to their implementation.

Also, in the Joint Motion of Chairman Brown and Commissioner Powelson on February 25, 2016, the Commissioners urged utilities to "promote the consideration of special natural gas rates for owners and operators of CHP facilities". Columbia's proposal regarding large commercial and industrial customers will respond to this request.

Q. How does Columbia further propose to expand natural gas service in this case?

A. Columbia has developed two additional incentives that, in conjunction with the three programs approved in the previous rate case, will further enable more customers to elect natural gas service: (1) reimbursement to builders/developers for the installation of house piping and/or venting in multifamily homes when projected revenues exceed projected costs by a certain threshold, and (2) the ability to charge rates for large commercial and industrial ("C&I") customers above current tariff rates in lieu of paying the entire deposit up front to cover the cost of enabling the C&I customer to receive natural gas service.

II. Multifamily House Line Reimbursement

Q. Please explain the Multifamily House Line Reimbursement program.

A. As stated earlier, the Company runs an economic analysis for customers who request a main line extension. For multifamily housing projects where the economic analysis result is positive, the Company proposes to reimburse developers up to the positive NPV for the project, but no more than $1,000 per unit for the cost of installing house piping or venting to each unit.

Similar to the residential house piping program that was approved in the Company's 2015 rate case, in order to obtain reimbursement, the Company is proposing that the builder or developer pay for the work to be done in the units and then provide the Company documentation that the work has been completed.

Q. Will the cost of the 150 feet of main and service line be included in the economic analysis to determine if the builder/developer is eligible for a house piping reimbursement?

A. Yes, similar to the residential house line reimbursement program, even though the Company will extend its main 150 feet and install 150 feet of service line, in areas where the Company owns the service line, at its own expense for each customer, these costs will be placed in the economic model when determining if the builder/developer is eligible for a house piping reimbursement, so that existing customers do not subsidize new customers for house piping.

Q. Who will be eligible for this program?

A. To be eligible for this program, a builder and/or developer must be either converting an existing multi-unit residential building or constructing a multi-unit residential building that includes natural gas as a fuel source for each individual unit. The builder or developer must agree that each unit will have a separate Company gas meter.

Q. Why is Columbia proposing this reimbursement?

A. Multifamily construction is trending upward in the United States. Please see Exhibit

RCW-1 for more details. However, because of the time and costs associated with installing extensive additional piping and venting throughout a multifamily building to comply with building code and natural gas installation requirements, developers often choose to use electricity for the energy needs of the building. This is not an ideal situation for residents of multiunit residential buildings, as they end up paying more out of pocket for energy consumption, because electricity is a more expensive energy source than natural gas.

Q. Please explain your statement that choosing to use electricity for energy needs is more expensive than natural gas.

A. Below is a chart that compares the estimated annual heating costs and water heating costs of natural gas compared to electric in Pennsylvania.

Table

	Annual Heating Costs	Annual Water Heating Costs	Total Annual Energy Costs
Natural Gas	$927	$354	$1,281
Electric	$1,610	$852	$2,462

This table reflects space heating costs, which are based on current Columbia Gas of Pennsylvania rates and EIA rates for electric. The annual energy use is based on an average of 87.7 MMBTU. Space heating equipment used to calculate the costs are standard efficiency 80% for natural gas and standard efficiency 7.7 HSPF for electric heat pumps. Water heating costs are all based on storage water heaters.

To remedy this situation, Columbia proposes to offer an incentive for developers to install the necessary additional piping and venting so that new or converted multifamily buildings are capable of receiving natural gas service.

Q. Will existing customers be subsidizing new customers on the house piping/ venting proposal?

A. No, as stated, Columbia will never reimburse a customer enough to cause the project to return a negative result. Because the reimbursement can only go as high as the positive result of the project, existing customers will not be subsidizing the costs of new customers' piping or venting. In fact, because of the reimbursement limit equal to $1,000 per unit, there will be some cases where the NPV of the project is high enough to provide a benefit to existing customers. Below are two scenarios in which the builder or developer would like to install natural gas capabilities for a multifamily building, but without the assistance of the Company for house piping or venting installation, the projects would use another energy source.

Scenario	Units	Economic Analysis Result	Economic Result Per Unit	Available Reimbursement	Net Result
1	5	$3,000	$600	$3,000	$0
2	5	$8,000	$1,600	$5,000	$3,000

In scenario 1, the economic analysis yields a positive result of $3,000, or $600 per unit. In this case, the Company would reimburse the developer up to the positive NPV of the project, $3,000, yielding a Net Result of $0. The economic model guides the Company to make the investment of the main extension for any project with a net result greater than or equal to $0. Even with the Company contribution to piping/venting installations, the project would still be economically justified. To put it another way, the rates that the new customers will pay will fully cover the investment of adding them to the system including paying the incentive to the builder and/or developer. Therefore, the effect to existing customers is the same as if a project with an economic analysis net result of $0 was built for customers without any money given in contribution to house piping or venting.

In scenario 2, the economic analysis yields a positive result of $8,000, which is an average of $1,600 per unit. In this situation, the Company would reimburse the developer up to $5,000 for house line installations in the five units, since the Company's limit on reimbursement per unit is $1,000. The net result is a $3,000 benefit to existing customers from the new customers being added to the system because the projected revenues exceed the projected costs, even including the cost of reimbursement for the house piping/venting.

Q. Why did the Company set a reimbursement limit unit of $1,000 per unit?

A. Columbia set the reimbursement limit of $1,000 per unit so that this program would be comparable to the Company's house line reimbursement program for residential customers.

Q. For ratemaking purposes, how will the Company record the cost of house piping/venting reimbursements?

A. The Company will record the cost of reimbursing house piping/venting as an O&M expense.

Q. Has the Company included any projected costs for this program?

A. Yes, Exhibit RCW-2 illustrates the net cost of this program to ratepayers based upon the incremental costs the Company would incur and revenues that the Company would collect if this program were to be approved. The net cost of this program is included in Witness Miller's Cost of Service as an O&M expense. I note that for each project the reimbursement is a one-time expense, but the Company expects that the program will encourage additional projects each year.

Q. How did the Company develop the projections for this program?

A. Columbia used historical data from the multiunit housing projects that the Company has previously evaluated in the economic model to develop the projections for this program.

III. <u>Large Customer Incentive</u>

Q. What does the Company propose for large customers who wish to begin receiving natural gas service in this case?

A. For new applicants projected to use more than 64,400 therms annually, the Company proposes that it have the ability either to receive the full deposit up front, or to negotiate to receive some or all of the deposit over time, through an increase to charges to the customer. This negotiated rate would be above the Company's current applicable rate structure to recover from the customer the uneconomic costs of the main line extension to serve the customer. The rates portion of the deposit to be paid up front and terms of the agreement would be stipulated on an individual basis between each customer who elects this option and the Company.

Q. Why is the Company proposing this option?

A. The deposit amount is often the biggest barrier for customers to convert to natural gas. By having the option to eliminate or reduce the deposit through an alternative rate structure, the Company will help more customers convert to natural gas and enjoy the savings of this efficient natural resource. This new incentive will promote the growth of new businesses and economic development within the Commonwealth, including, but not limited to, Combined Heat and Power ("CHP").

IV. <u>Transaction Fees Proposal</u>

Q. Please describe the scope of Columbia's proposal to include all residential payment channel fees in the cost of service.

A. Currently, Columbia customers can make bill payments via mail, monthly debit from their financial account, authorized walk-in locations, one time electronic payment as a registered on-line account holder, and through a third party processor via debit card, credit card or Automated Clearinghouse ("ACH") electronic payments. The processing fees associated with all but the third party credit card, debit card, ACH and walk-in locations are included in the cost of service calculation.

In this case, Columbia is proposing that all costs, including those associated with credit card, debit card, ACH electronic payments and walk-in customer payments, be included in the cost of service calculation. If approved, all residential customers will be able to select the payment channel of their choice without consideration of additional convenience or transaction fees.

Q. Please describe the residential customer benefits resulting from Columbia's inclusion of all payment channel fees in the cost of service.

A. The inclusion of these fees in the cost of service is designed to enhance the overall experience of Columbia's customers. Customers frequently comment via surveys that they would prefer to pay online via the method of their choice, and without incurring an additional fee to do so. Customers responding to the Company's internal survey results echoed this suggestion. Please see Exhibit RCW-3 for customer comments regarding payment fees. Benefits of including all payment transaction fees in the cost of service include the following:

- Elimination of the convenience fee to customers for electronic payment through our third party processor for credit card, debit card and ACH transactions;
- Elimination of transaction fees for bill payment at one of Columbia's authorized walk-in locations;
- Encourage customer use of Columbia's authorized agents, thus avoiding delays in processing payments made through unauthorized agents; and,

- Increased customer satisfaction by allowing customers to pay via the channel of their choice – free of charge.

Q. What is Columbia's long term customer bill payment channel strategy?

A. Customer expectations are constantly changing, as companies focus on improving customer satisfaction and addressing changing needs due to technological advancements (e.g. tablets, smart phones, etc.). Columbia's goal is to work diligently to offer a variety of customer-focused payment options to address evolving payment expectations and improve the customer experience.

Q. What is the amount of the transaction fee annual costs that are included in this cost of service?

A. This cost of service includes annual transaction fees associated with projected payment volumes resulting from the elimination of all customer fees for credit card, debit card, ACH electronic payments and walk-in customer payments. Columbia estimates that credit/debit card payment volumes will almost double as a result of plans to offer these payment channels at no additional charge per transaction. The projected annual costs for credit cards and walk-in payments the initial year are estimated to be $516,954. The details for the cost and projected volumes for each transaction are detailed on Exhibit RCW-4.

Q. Please summarize your tariff change and transaction fees proposals.

A. The Company proposes to reimburse builders/developers up to $1,000 per unit for the installation of house piping on multifamily homes when projected revenues exceed projected costs by a certain threshold. In addition, the Company proposes to reduce or eliminate the deposit for large commercial and industrial customers who agree to a negotiated rate for gas service. Finally, the Company proposes to waive all transaction fees associated with the payment of residential customers' bills and include these costs in the cost of service.

Q. Does this conclude your direct testimony?

A. Yes, it does.

Freddie Mac
MULTIFAMILY

Multifamily Outlook 2016

Executive Summary

Demand for multifamily rental housing was higher than expected in 2015, absorbing much of the newly completed supply. Therefore, vacancy rates remained low and rents continued to rise in most markets. As more supply enters the market in 2016, multifamily fundamentals will moderate, more so in some geographic markets than others.

Sustainable Market Growth

Steady economic growth and key drivers will keep the multifamily market moving forward in 2016.

- Multifamily rental demand kept pace with the large wave of new supply in 2015 and will remain strong into the foreseeable future.
    - Favorable demographic trends, strength in the job market and reduced affordability of owning a home will continue to fuel strong demand for multifamily rental units.
    - As more supply enters the markets, the national vacancy rate will increase slightly, but it will remain less than the historical average through 2016. As a result, rent growth will remain strong until new supply can catch up with demand.
- In 2015, 306,000 multifamily units were completed and entered the market – the most in a single year since 1989. The level of new multifamily supply is expected to remain elevated over the next few years, given that the number of new construction permits rose again in 2015.
- The labor market added 2.7 million jobs and is near full employment as the unemployment rate finished 2015 at 5 percent. The strengthening labor market will put upward pressure on wage growth in 2016.
- Despite the Federal Reserve's decision to increase interest rates in December 2015, multifamily property price growth will remain strong and capitalization rates will not be significantly affected in the short-term.
- Multifamily origination hit record volume in 2015. It may have another record year in 2016 because of increasing property prices, new completions and maturities, all of which present favorable investment opportunities.

Vacancy and Rent Growth at the Geographic Market Level

For the majority of markets, vacancy rates remain below and rent growth above their historical averages. Gross income growth (average rent adjusted for vacancy) is mixed across markets and will further disperse as new supply enters the markets.

- Our top 10 list of metros based on 2016 gross income growth is dominated by West Coast markets, the exceptions being New York and Chicago.
- Vacancy rates in Washington, D.C. will increase further above their historical average in 2016; but multifamily construction started to slow down at the end of 2015. Boston, Jacksonville, and Norfolk are also projected to finish 2016 with vacancy rates above their historical average. Stronger-than-anticipated demand in Austin will outpace supply in 2016, keeping vacancy rates below the historical average.
- As oil prices near decade lows, several metros in Texas along with Denver will feel the impacts as employment growth slows as a result.

- Employment growth forecasts available to us forecast Houston growth will remain positive in 2015, but well below levels seen in the past few years. Vacancy rates will increase through 2016 and rent growth will moderate but remain strong enough to beat historical averages.
- Denver and Fort Worth will also see employment growth fall short of the last few years. Multifamily fundamentals will remain robust there, but with more moderation.

Multifamily Market-level Sensitivity Analysis

We test the sensitivity of multifamily performance across a range of economic growth forecasts from Moody's Analytics; strong growth, slow growth, moderate recession and low oil prices. These analyses reveal that even in stressed scenarios, gross income in nearly all markets is projected to grow, albeit at lower rates compared to the baseline scenario.

- In the strong growth scenario, gross income will grow more than the baseline scenario, but only by a modest amount because of the already above-average performance seen in the majority of markets.
- In the case of slow growth, all metros will see potential for lower gross income growth, but the majority will remain above their historical averages. A moderate recession will cause all metros to drop to or below their historical averages; some will turn negative.
- In the low-oil-price scenario, markets in Texas – including Houston, Austin, Dallas, San Antonio, and Ft. Worth – along with Denver and Oklahoma City would feel the biggest impact on gross income growth in 2016, but growth will remain above historical averages in each of those markets, except for Houston and Austin.

Multifamily Outlook 2016

- The multifamily rental market experienced its strongest post-recession growth in 2015, despite a wave of new supply.
- In 2016, new supply of multifamily units will continue to enter the market at levels not seen since the 1980s; meanwhile, plans for additional construction continue to increase.
- Multifamily performance at the national level will remain robust into 2016, but some individual markets are starting to moderate.
- We stress test multifamily performance based on strong and weak economic forecasts. Our analysis indicates even if economic growth slows down, gross income will continue to grow in nearly all markets, albeit at lower rates compared to the baseline scenario.

The multifamily rental market had another fantastic year in 2015. Demand kept pace with new supply, despite a large wave of new properties delivered to the market. Vacancy rates barely budged and rent grew at the highest rate since 2000. The market's extended period of growth confirms that rental housing is a growing segment of the housing market and not just experiencing a temporary correction after the Great Recession.

In 2016, we expect another good year for multifamily. Despite some headwinds in the economy, favorable demographic trends and economic growth will fuel household formations and strong multifamily growth. As more supply is delivered, most markets will moderate, but market cooling is not a given. Looking back over the last few years, some markets with the greatest gross income growth (average rent adjusted for vacancy) were those taking on a significant amount of new supply.

Low oil prices, reduced housing affordability in both rental and ownership and interest rate adjustments will also impact the multifamily market, some metros more than others. Although fundamentals began to moderate slightly by the end of 2015, more factors are poised to encourage continued growth than to constrain it.

Section 1 – Multifamily Market Drivers

The economy continued to improve steadily during 2015 and most macro-economic forecasters expect the trend to extend through 2016. Gross domestic product (GDP) for 2015 was revised downward to 1.8 percent, but still subject to revisions, and predictions for 2016 are in the range of 2.5 percent. While this level of economic growth will allow the economy to continue its steady recovery, the growth falls below the long-run average of 3.2 percent going back to 1948. However, on average, the economy is expected to see more moderate growth in the long-term. The Bureau of Labor Statistics stated in its Employment Projections 2014-2024 report, with more people retiring, labor-force growth will slow and lead to suppressed economic growth at the national level. GDP is expected to grow only 2.2 percent on average per year over the next decade.

The Federal Reserve increased short-term interest rates in December 2015 for the first time in nearly a decade. The Fed's decision to raise rates came from steadily declining unemployment, consistent real economic growth, and a strengthening housing sector. Tighter monetary policy is not expected to generate a spike in longer-term interest rates in the near-term, however. Mortgage rates will rise modestly but remain near historical lows. Continuing strong job and income growth will result in increasing household formations through 2016.

Global geopolitical issues that influence economic conditions are often unpredictable but still can affect real estate investment conditions. Many foreign investors still turn to U.S. Treasury bonds (Treasuries) as a stable investment during instability, keeping the long-term interest rate low and strengthening the dollar. However, the impact of a major global slowdown could ripple through the U.S. economy.

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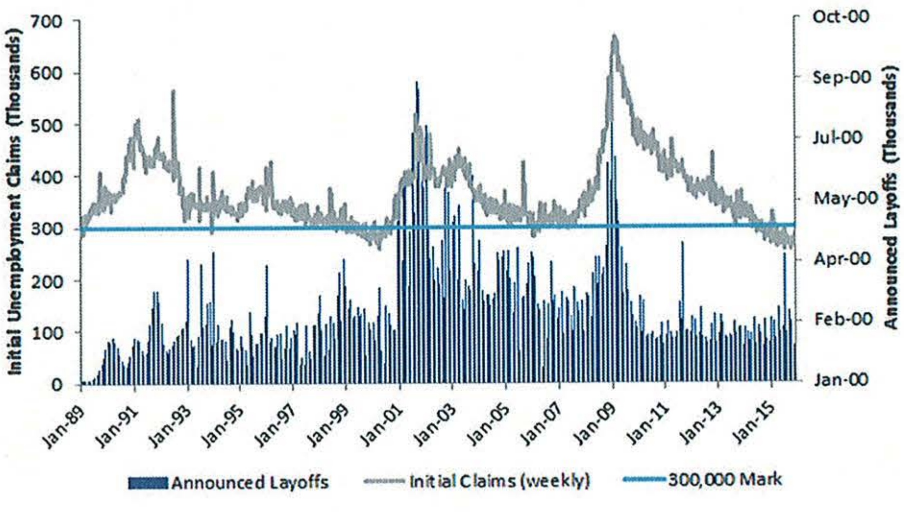
Economy Near Full Employment

Employment growth remained strong in 2015, albeit more subdued than in 2014. A total of 2.7 million non-farm jobs were added, the second largest annual gain since 2000. The unemployment rate dropped 60 basis points (bps), to 5 percent, in 2015. Similar job growth is expected in 2016, but only lowering the unemployment rate to 4.8 percent, as more people who stayed on the sidelines are expected to enter the labor force. Most industries will continue their healthy growth, except for manufacturing and energy; the strong dollar and struggling oil prices have led to slowdowns in these two industries.

Despite the low unemployment rate and high number of job openings, wage growth continues to disappoint. Wage growth in 2015 was stronger than in previous years, but the modest gains compared to historical growth indicate slack in the labor market. Job growth slowed across all wage tiers in 2015 compared to 2014, but all tiers are still hiring. According to Witten Advisors, middle-wage jobs had the most job gains in 2014 and 2015, outpacing low-wage job growth that dominated the first three years following the Great Recession. Meanwhile, high-wage job gains were hurt in 2015 partially because of the energy sector's contraction.

Announced layoffs in 2015, according to the Challenger Report, were at their highest since 2011 at 598,510. The energy sector announced the most layoffs, with 94,409 in 2015 compared to 14,262 in 2014. However, weekly initial unemployment claims have been below 300,000 – a level generally indicative of a strong labor market– for 46 straight weeks, as of January 16. This is the longest streak of claims below 300,000 since at least 1989, as shown in Exhibit 1.

Exhibit 1: Announced Layoffs and Initial Unemployment Claims



Sources: U.S. Employment & Training Administration; Challenger, Gray & Christmas, Inc.; Freddie Mac

Strong Rental Household Formations

The strength in the broader economy and labor market continues to fuel household formations. Total household formations increased by 1.5 million in the first nine months of 2015. While slightly lower than the prior three quarter's year-over-year change, it marks the fourth quarter that total formations exceeded one million.

Household formations have been heavily skewed toward renters over the last nine years, as shown in Exhibit 2. Since 2007, eight million renter households have been formed, while owner-occupant households have decreased by 1.8 million. The homeownership rate did increase 30 bps over the prior quarter to 63.7 percent, the first quarter-over-quarter increase since third quarter of 2013. The pick-up in ownership most likely resulted from households who were on the fence about owning finally taking the plunge before an anticipated interest rate hike.

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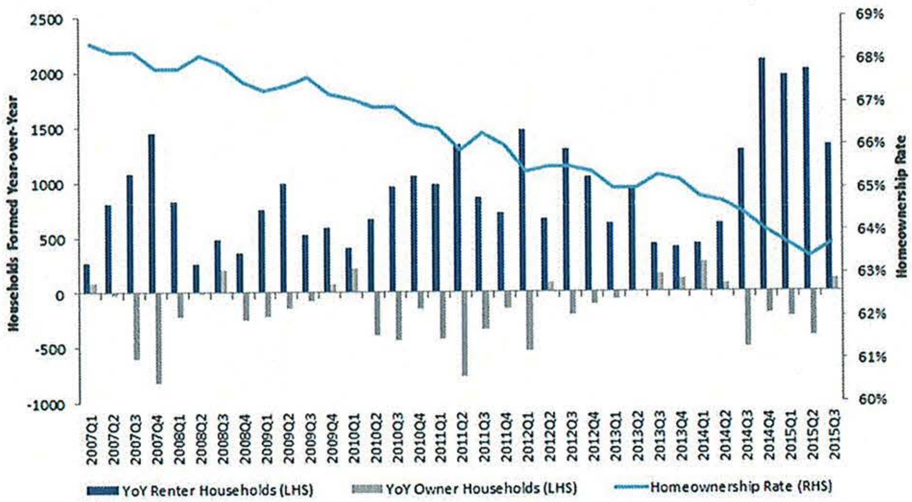
Increased owner-occupancy will positively affect rental housing in the long-run; more household formation, regardless of tenure, benefits the economy, creating more jobs, which spurs further household formations.

Exhibit 2 - Annual Renter and Owner Household Formations and Homeownership Rate (2007Q1 - 2015Q3)



Sources: U.S. Census Bureau, Freddie Mac

One factor that could slow renter household formations is the declining affordability of rental housing. There is a growing disconnect between renter income and asking rent for new multifamily units. Many new units are not built to accommodate households in the lower-income distribution. According to the Joint Center for Housing Studies (JCHS), only 10 percent of new units built had asking rents at levels considered affordable to about half of the renter population.

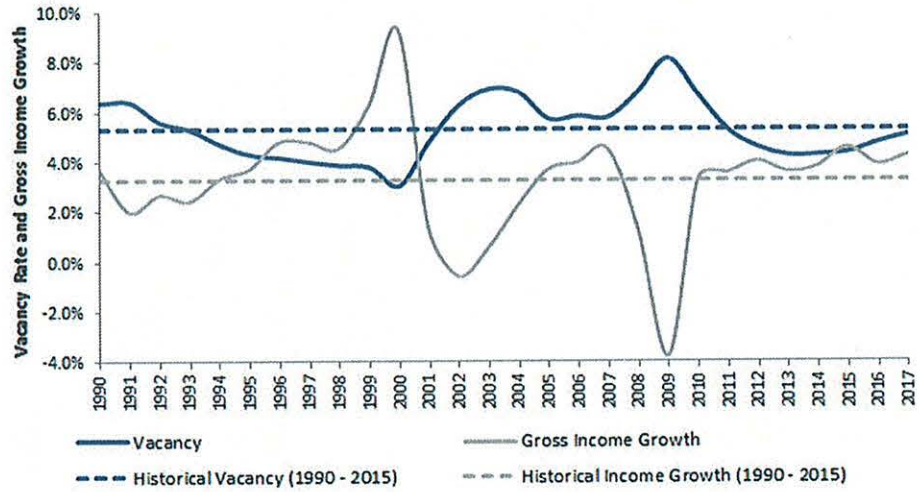
Despite reduced housing affordability, we expect renter household formations to remain strong because of favorable demographics and pent-up demand following the Great Recession. While the pace of renter household formations is expected to slow from the robust pace of the past few years, the JCHS estimates 4.4 million renter households will form by 2025 based on adult population growth alone.

Exceptional Multifamily Performance

The multifamily sector performed better than anticipated in 2015 despite the large flow of new completions to the market. Vacancy rates barely budged, increasing to 4.4 percent from 4.3 percent. Gross income growth reached 4.6 percent in 2015, exceeding expectations and reaching the highest level of growth since 2000, according to REIS. A combination of stronger-than-anticipated demand and slower-than-anticipated property deliveries suggests that multifamily market fundamentals will remain solid.

Through 2016, multifamily supply will continue to enter the market at elevated levels. Demand will remain strong enough to absorb most of the units, but supply is expected to outpace demand by the end of 2016. Vacancies will rise slightly to 4.8 percent and gross income growth will remain above historical average at 3.9 percent by year-end, as shown in Exhibit 3.

Exhibit 3 - Vacancy Rate and Gross Income Growth, History and Forecast

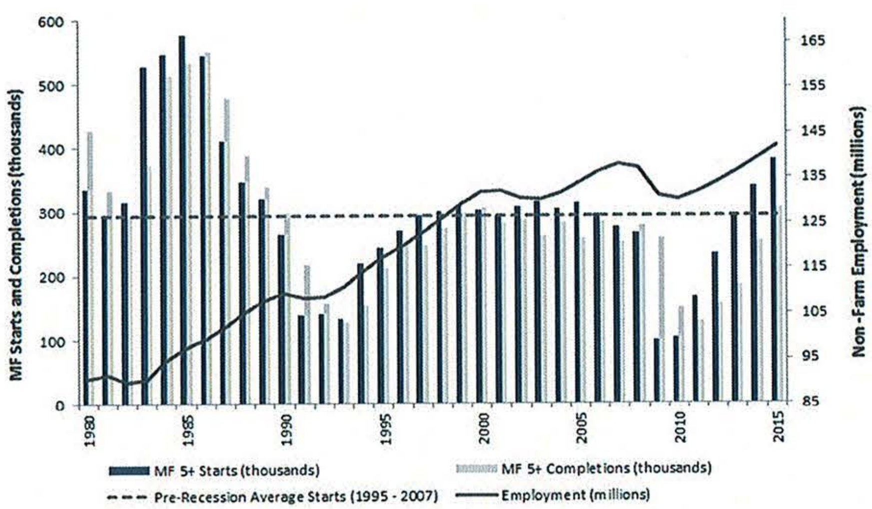


Sources: REIS, Freddie Mac projections

Multifamily Completions Up, Total Housing Supply Insufficient

Multifamily completions in 2015 hit 306,000 units, slightly more than the previous cyclical peak of 305,000 in 2000 and the most since 1989, as shown in Exhibit 4. In second quarter 2015, the market registered the largest quarter-over-quarter increase in completions since 2000, with 80,000 new units delivered. The multifamily market's performance throughout 2015 indicates that demand met the large amount of new supply.

Exhibit 4 - Multifamily Starts and Completions (5+ Units) and Employment



Sources: Freddie Mac, U.S. Census Bureau, Moody's Analytics

Multifamily starts continued to increase in 2015, as shown in Exhibit 4, indicating that completions will remain at high levels through 2016 and 2017. The elevated level of multifamily construction is a testament to many investors' confidence in the multifamily sector. By the end of 2015, multifamily performance started to moderate under the weight of new deliveries, causing some investors to worry that new construction will outpace demand.

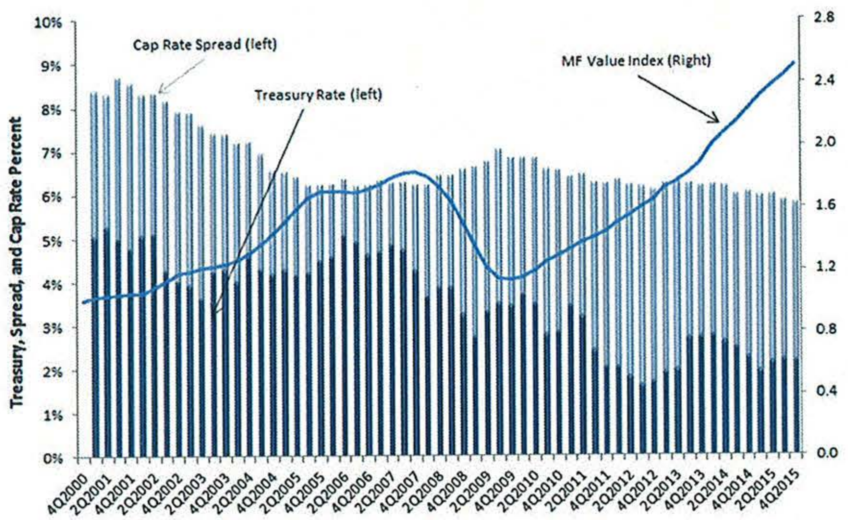
One crucial factor to consider is the overall level of housing supply. Despite the large increase in multifamily starts, the total number of housing starts in 2015 (which includes one-unit, two- to four-unit, and five-plus-unit buildings) was 30 percent less than the historical average, measured from 1970 to 2007. Therefore, the housing market is experiencing below-average housing construction, creating a shortage of total housing supply, which is being partially filled by the increase in multifamily construction.

Strong Property Price Appreciation and Rising Interest Rates

Multifamily property prices have grown remarkably since the low that followed the Great Recession. Surging demand and lack of supply have resulted in annual price appreciation between 13 and 15 percent. As of December 2015, property prices were 38 percent higher than the pre-recession peak. There is a concern, however, that the Federal Reserve's decision to increase interest rates in December 2015 may have a negative impact on property prices. Another concern is that property prices are growing faster than property cash flows which is not sustainable for an extended period of time.

Multifamily capitalization rates (cap rates) are not expected to be significantly impacted by the interest rate hikes in the short-term. The spread between cap rates and the 10-year Treasury remains historically wide, as shown in Exhibit 5, and will be able to absorb some of the interest rate increases. As of December 2015, cap rates dropped below 6 percent to 5.9 percent, according to Real Capital Analytics (RCA). Cap rates for the higher quality properties in more desirable locations are typically lower than the overall average, and have been around 5 percent since mid-year 2014. These markets have seen some of the strongest price appreciation and cap rates are expected to remain around 5 percent. For the overall multifamily market, we project that cap rates could increase slightly but will stay in the low 6 percent range through 2016. This forecast assumes steady employment growth, the 10-year Treasury rate remaining below 3 percent, and spreads continuing to tighten mildly to 300-330 bps.

Exhibit 5 - Multifamily Value Index, Cap Rate Spread and Treasury Rate



Sources: Freddie Mac, RCA CPPI™, U.S. Census Bureau, Moody's Analytics

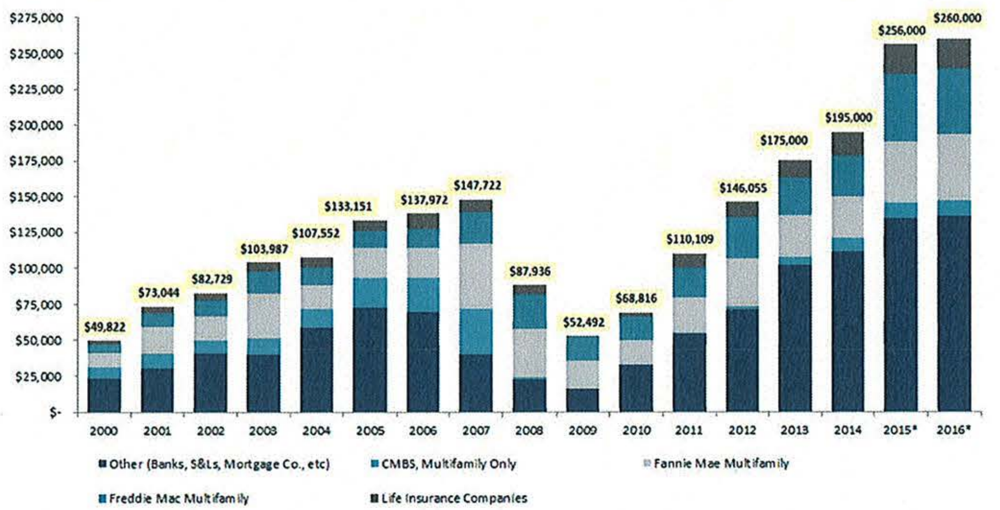
Record Origination Volume

Multifamily origination volume is expected to set another record high in 2015, at $256 billion. We expect origination volume to be even higher this year, because of increasing property prices, increasing construction pipeline, a large wave of maturities, and a relatively low – albeit starting to rise – interest rate environment. As shown in Exhibit 6, we anticipate that 2016 origination volume will reach between $250 billion and $260 billion.

The growth among the government-sponsored enterprises (GSEs), Freddie Mac and Fannie Mae, constituted the largest portion of the 2015's increase over 2014. As the economy continues to improve, other market participants will increase their market presence.

However, a change in regulatory guidelines on banks could create a headwind for origination volume. U.S. regulators expressed concern about the growing commercial real-estate sector and the possible rise in risky lending. The regulators may require banks to hold more capital or take other actions in 2016 if their commercial real-estate lending is deemed more risky. These regulator actions could affect the amount of multifamily volume banks can originate and lower the total 2016 volume.

Exhibit 6 - Multifamily New Purchase and Guarantee Volume ($ Millions)



Sources: Mortgage Bankers Association, Freddie Mac
Notes: 2015 and 2016 numbers are projections as of December 2015

Section 2 – Multifamily Market-level Outlook

Many metropolitan areas have had exceptional growth in their multifamily sector, thanks to strong demand. Stronger-than-anticipated demand in 2015 kept rent growth above historical average in many markets.

Our list of the top 10 markets based on forecasted gross income growth for 2016, is shown in Exhibit 7, along with actual growth for 2015, as reported by REIS. The ranking of markets remains consistent with previous results as many of the top 10 are West Coast markets, mostly in California. Chicago and Orange County moved into the top 10 as limited new construction has allowed rents to grow while vacancy rates stayed low. But in most of these markets performance is expected to be slower in 2016 than in 2015, except in Chicago, Orange County, and Los Angeles where gross income growth will accelerate in 2016.[1]

[1] Our forecasts also incorporate an update to our forecasting model. Adjustments were implemented to capture more movements among metros, which led to higher rent growth in some markets. These updates and results are consistent with market expectations and provide a better forecasting model for future vacancy rates and rent growth.

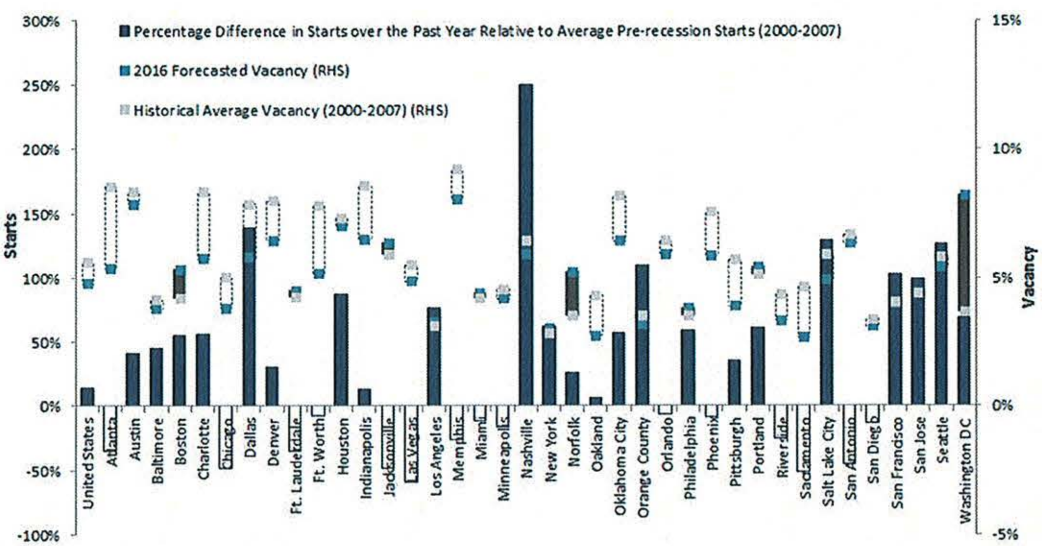
Exhibit 7 - 2016 Forecasts for Top 10 Metro Markets' Gross Income and Vacancy

	Annualized Growth in Gross Income		Vacancy Rate	
Metropolitan Market	2016	2015	2016	2015
San Francisco, CA	8.2%	10.7%	4.0%	4.1%
Oakland, CA	6.5%	6.5%	2.8%	2.7%
Seattle, WA	6.0%	7.4%	5.4%	5.3%
Los Angeles, CA	5.9%	5.0%	3.3%	3.3%
Sacramento, CA	5.8%	7.0%	2.7%	2.4%
San Jose, CA	5.2%	5.5%	4.4%	3.9%
New York, NY	5.2%	6.0%	3.0%	3.1%
Orange County, CA	5.2%	3.7%	3.2%	3.0%
Chicago, IL	5.1%	3.5%	3.8%	3.8%
Portland, OR	4.9%	6.2%	5.4%	5.0%
United States	3.9%	4.6%	4.8%	4.4%

Source: REIS, Freddie Mac projections

On the supply side, many markets continue to experience above-average construction, but vacancy rates in most of these markets will remain below average, as shown in Exhibit 8. Supply started to moderate in many markets by the end of 2015, which will help them absorb the new inventory and continue to grow at or above historical average levels. Construction levels in a few markets were higher by the end of 2015 than six months prior, such as Nashville, Dallas, and Salt Lake City. However, vacancy rates in these three markets are expected to stay below their historical averages in 2016.

Exhibit 8 - Multifamily Starts and 2016 Forecasted Vacancies Relative to History

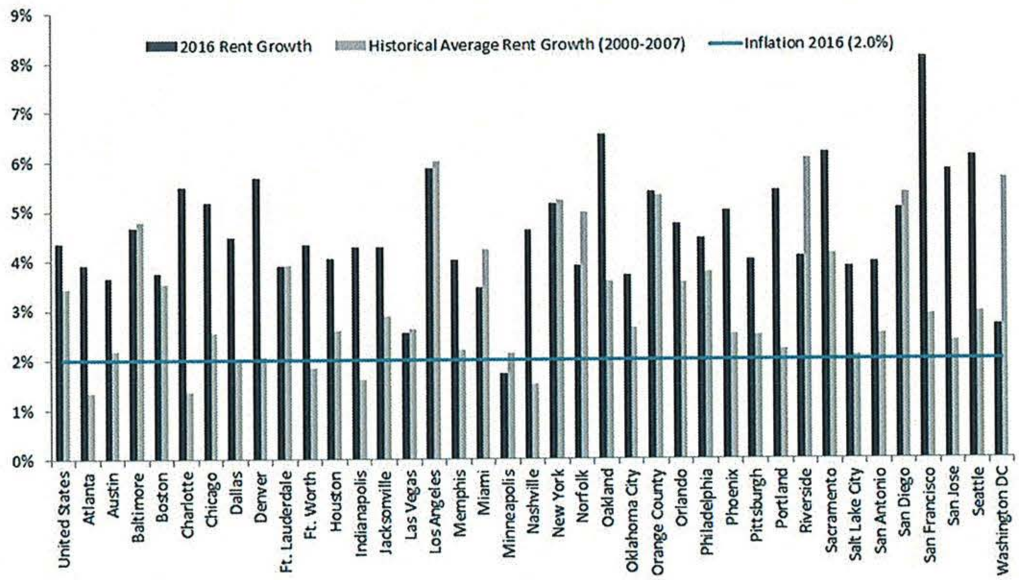


Sources: REIS, Moody's Analytics, Freddie Mac projections

Despite a meaningful slowdown in construction in the Washington, D.C. area over the past six months, the gap between 2016 and historical vacancy rates will widen as new supply enters the market. Boston, Jacksonville, and Norfolk will also most likely experience vacancy rates in 2016 above their historical averages. Vacancy rates in most markets will increase as new supply becomes available over the course of 2016; nevertheless, vacancy rates will stay below average in the majority of the markets.

In 2016, rents will grow more slowly than in 2015 in the majority of metros but still at a pace above historical averages and the expected inflationary target of 2 percent, as shown in Exhibit 9. Expectations are higher than previously forecast because of stronger-than-anticipated demand and expected wage growth. Strong demand will put upward pressure on rents, while increased wages will boost household formations and allow some to upgrade their living situations. Most metros will see growth rates moderate in 2016, but much less than previously anticipated. The relatively low vacancy rate in most markets also will continue to contribute to the strong rent growth; high occupancy coupled with high demand allows landlords to increase rents.

Exhibit 9 - Rent Growth Forecasts for 2016 Relative to History



Sources: REIS, Freddie Mac projections

Rents continue to grow most in markets in California as well as Seattle. The markets forecasted to experience the least rent growth are generally those that have gained significant supply in recent years, such as Washington, D.C. and Austin, or weaker economies, like Minneapolis and Las Vegas. Rents in Washington, D.C. and Minneapolis, despite a relatively strong showing in 2015, will roll back in 2016. Minneapolis has been experiencing a relatively strong rebound so far, but in 2016 employment growth is projected to slow down due to the strong dollar constraining the manufacturing sector, a key employment sector in Minneapolis, and subsequently slowing rent growth below its historical average. Meanwhile, in Austin and Las Vegas, rents are rising less than in most other metros but are still growing at or above historical averages.

Despite the low oil prices, most energy dependent areas continue to perform above average. Houston has the most risk associated with low oil prices and has seen the largest slowdown in employment growth. Annual non-farm employment growth slowed to 0.8 percent, as of November 2015, significantly below the pace achieved in the last few years. As a consequence, Houston's 2016 rent growth and vacancy rates will moderate but perform inline or better than the historical average.

Other energy dependent metros have been much less affected by oil price drops than Houston; as a result, job creation has not slowed as much. Annual employment growth in Austin, Dallas, and San Antonio remained strong through November 2015 and is on pace to match the annual growth rates of the last two years. In Ft. Worth, job growth slowed below the national average as of November 2015, but this market did not experience the rapid job growth that other Texas metros did in the past few years. Meanwhile, outside of Texas, job growth slowed in Denver compared to prior years, but is still above the national average.

If oil prices remain near or below $35 per barrel over the next several months, the labor markets in these markets could be impacted more severely, which would put further stress on their multifamily fundamentals.

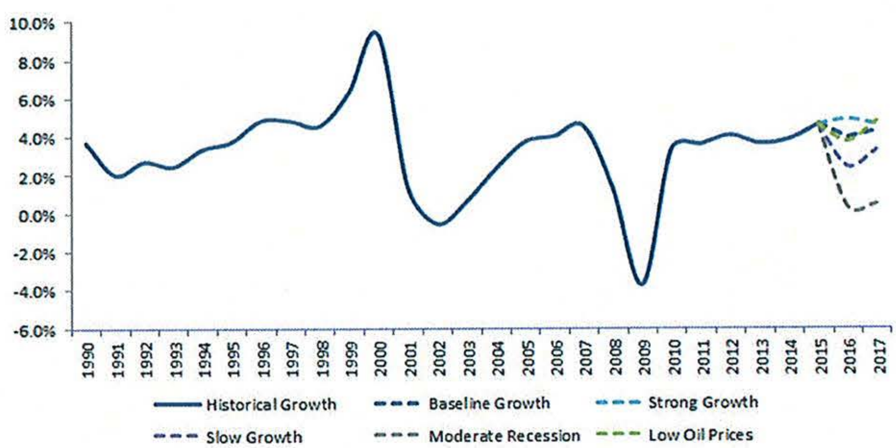
Section 3 – Multifamily Market-level Sensitivity Analysis

To assess the potential outcomes of multifamily performance for 2016, we project gross income growth across a range of economic forecasts that come from Moody's Analytics.[2]

We ran our multifamily market performance model based on Moody's Analytics baseline scenario and compared it to four alternative economic scenarios: stronger near-term growth, slower near-term growth, moderate recession, and low oil prices.[3] Each scenario includes assumptions related to the strength of the dollar and subsequent U.S. exports, Europe's and China's potential growth, oil prices, and interest-rate movements. These assumptions have varying impacts on drivers that affect gross income growth; employment, house price appreciation, consumer price index, and per capita income. While most industry participants expect consistent growth will continue into 2016, others anticipate a slowdown in the near-term. From our results, we can see that a slow-growth scenario would not be enough to derail most multifamily markets; however, a moderate recession would cause all markets to drop below their historical average gross income growth.

Exhibit 10 shows the results of our analyses at the national level. Multifamily performance previously described in Section 2 was forecasted using the baseline scenario. As mentioned, gross income will moderate in 2016 as vacancies increase and rent growth slows. A stronger economy in the near-term will drive more job growth, higher per capita income, higher inflation, and higher single-family house prices, all of which will bolster multifamily performance. On the other hand, a more sluggish economy will hamper growth in all of these variables, which, in turn, will weaken multifamily performance. In the strong growth scenario, gross income growth is expected to be 4.9 percent and 4.6 percent in 2016 and 2017, respectively. On the other extreme, a moderate recession will drag gross income growth down to 0.3 percent and 0.5 percent in these years, respectively.

Exhibit 10 - Gross Income Growth Projected for Moody's Analytics Scenarios



Sources: REIS, Moody's Analytics, Freddie Mac projections

[2] Similar case studies were published in 2015 which looked at specific markets and the impact of different economic forecasts: "A Little Bit Country, a Little Bit Rock 'n' Roll": http://www.freddiemac.com/multifamily/pdf/little_bit_country_little_bit_rock_n_roll.pdf .
"Oil Price Impacts and Multifamily Housing": http://www.freddiemac.com/multifamily/pdf/oil_price_impacts_multifamily_housing.pdf

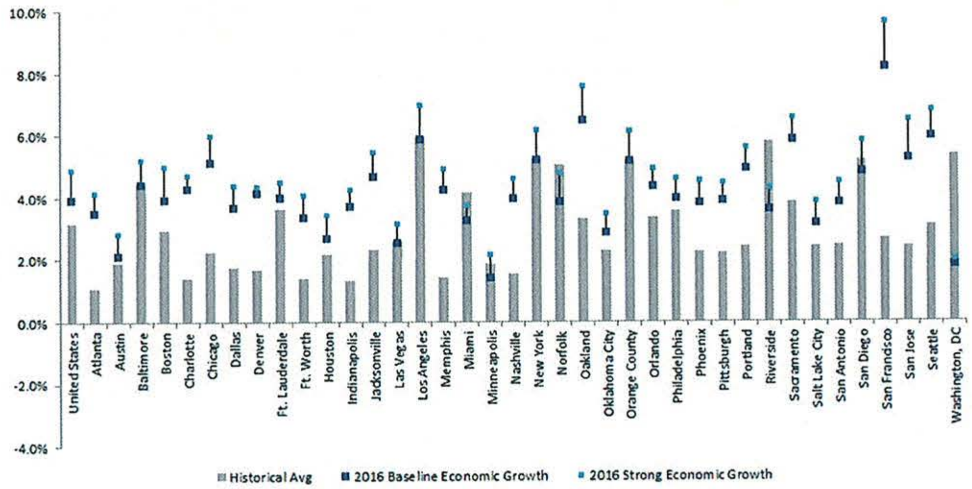
[3] The stronger near-term recovery scenario assumes the U.S. economy grows at a faster pace than the baseline scenario. The slower near-term recovery scenario projects a slower U.S. economy in 2016 but no recession. The moderate-recession scenario assumes the U.S. economy enters a recession in first quarter 2016 that lasts through fourth quarter 2016, but with less severity than the 2008-2009 downturn. The low-oil-price scenario assumes that West Texas Intermediate (WTI) remains near $35 per barrel through 2018 versus the baseline assumption that WTI will increase steadily to $70 per barrel during that period. For more information regarding the scenario assumptions, refer to Moody's Analytics. https://www.economy.com/home/products/samples/Moodys-Analytics-US-Alternative-Scenarios.pdf

Employment growth is one of the main drivers impacting multifamily performance. In the baseline scenario, employment grows by 1.9 percent in 2016. In the strong growth and low oil price scenarios, the economy would see more job growth than the baseline scenario because of a stronger economy. Job growth in these two scenarios is forecasted to be 2.4 percent and 2 percent, respectively. Meanwhile, in the slow growth and moderate recession scenario, employment growth slows to 0.9 percent and -0.9 percent, respectively.

Another key driver of multifamily performance is the amount of multifamily construction. But, any new completions delivered in the short-term forecast have already begun construction in the past two years and would not meaningfully impact the 2016 forecasts. However, these impacts would be seen in later years.

At the individual market level under the baseline scenario, most markets are expected to perform better than their historical averages in 2016. In the strong-growth scenario, the multifamily sector in all markets will experience even higher gross income growth in 2016, between 20 bps to 150 bps more, with an average increase of 70 bps. Exhibit 11 shows how results compare to the baseline. The additional boost in San Diego and Minneapolis will allow gross income to rise above their historical averages, whereas Norfolk, Riverside, Miami and Washington, D.C will still fall short of their historical averages.

Exhibit 11 - Gross Income Growth Scenario in 2016: Projected Strong Economic Growth

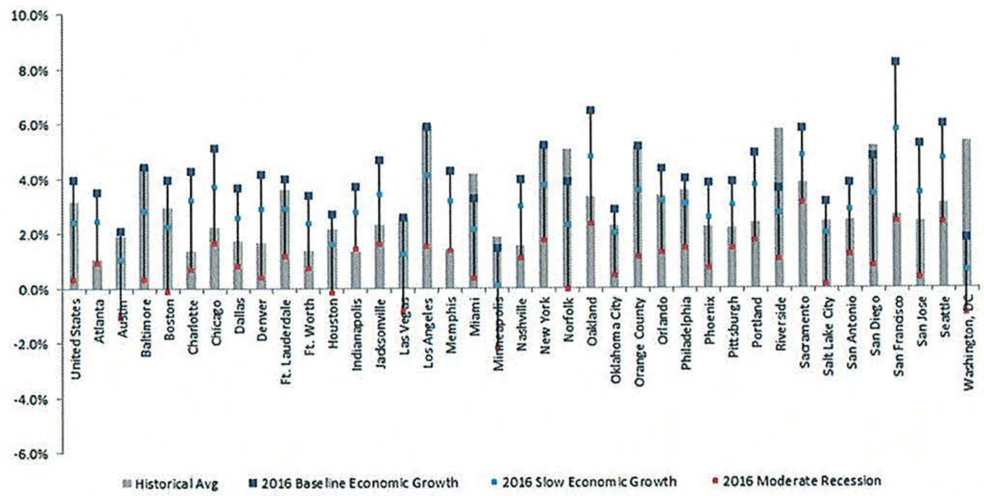


Sources: REIS, Moody's Analytics, Freddie Mac projections

The markets that will deliver the best results are those already expected to have the highest growth for 2016, including Los Angeles, Oakland, and San Francisco. Housing demand is already high in these markets because of strong employment growth; any additional household demand would push up gross income growth even further. Furthermore, any construction started in response would take a few years to complete.

In the slow-growth and moderate-recession scenarios, gross income growth will slow compared to the baseline scenario, as shown in Exhibit 12. The steepest declines will be in those markets with higher growth under the baseline scenario, such as the Bay Area and Southern California.

Exhibit 12 - Gross Income Growth Scenarios in 2016: Projected Slow Growth and Moderate Recession



Sources: REIS, Moody's Analytics, Freddie Mac projections

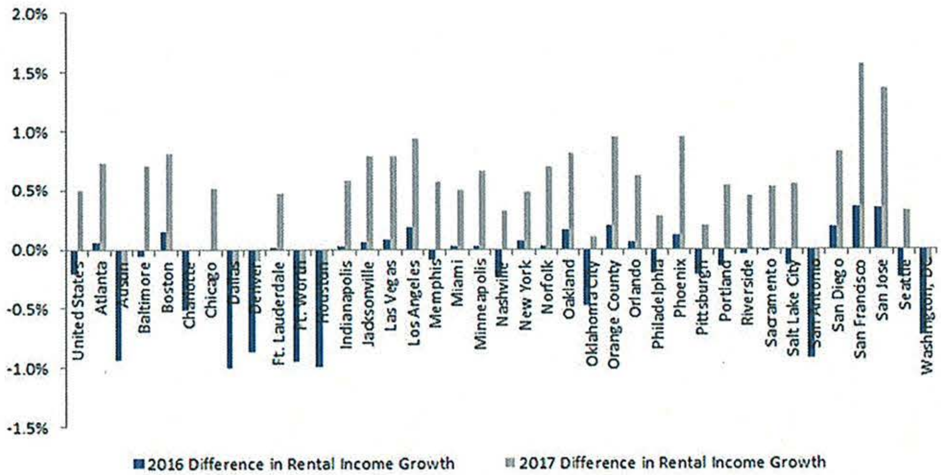
In the slow-growth scenario, gross income growth for most markets will remain above historical averages in 2016 but will be 130 bps less on average than in the baseline scenario. Growth will fall below the historical average in eight markets under this scenario: Austin, Boston, Ft. Lauderdale, Houston, Las Vegas, Orlando, Philadelphia, and Salt Lake City. Properties in these markets will have difficulty covering expenses and costs if new loans were based on historical performance.

The impact on multifamily performance is much more severe in the moderate-recession scenario. Most markets will experience a negative shock that will exacerbate the performance decline. On average, gross income growth will be 330 bps less than in the baseline scenario or another 200 bps less than the slow-growth scenario. All metros will experience gross income growth below or at their historical average levels.

In this scenario, gross income will shrink more than 4 percent in Boston, Los Angeles, Oakland, Orange County, San Francisco, and San Jose. It is not unexpected that the California markets, which had some of the highest income growth in 2016 under the baseline scenario, would expect a significant drop. Boston though, does not follow that same pattern of well-above historical income growth under the baseline scenario. Instead, Boston's sizable decrease in both scenarios is because of the relatively high vacancy rate compared to its historical average. In the event of a slowdown, there will be even greater pressure on vacancy rates to rise, causing rent and income growth to fall further.

In the low-oil-price scenario, projected performance across markets is mixed, as shown in Exhibit 13. In 2016, gross income growth in about half of the markets will be greater than in the baseline scenario and decrease in the other half.

Exhibit 13 - Change in Gross Income Growth from Low-oil-price Scenario to Baseline (2016-2017)



Sources: REIS, Moody's Analytics, Freddie Mac projections

For most markets, the impact will be minimal; but markets with a heavier reliance on the energy sector will feel a greater impact. In metros such as Austin, Dallas, Denver, Ft. Worth, Houston, Oklahoma City and San Antonio, gross income growth would decrease on average 90 bps compared to the baseline scenario. However, that decrease would only be enough for income growth in Houston and Austin to dip below the historical average. Income growth in the other five markets will decrease but remain above historical average in 2016. Washington, D.C. will also experience a significant negative impact to gross income growth; low-oil prices would boost employment growth but impact house prices which would negatively impact gross income growth in 2016.

However, the overall economic impact of lower oil prices will be positive once the energy sector stabilizes, beginning in 2017. That year, gross income growth at the national level will exceed expected growth in the baseline and strong-growth scenarios. Likewise, growth for the majority of the metros will be higher under the low-oil-price scenario in 2017, except Texas markets, Denver, and Washington, D.C.

Conclusion

Following a year that greatly exceeded expectations, the multifamily market overall will remain strong in 2016 but with more moderation. The wave of new supply that was delivered to the market mid-2015 was met with strong demand, keeping vacancy rates low and allowing landlords to increase rents. Fundamentals began to moderate by the end of 2015 as vacancy rates started to increase. Favorable demographic trends and an improving economy will generate robust demand for multifamily properties. Even if the economy experiences extended low oil prices or slow near-term growth over the next year, most multifamily markets will continue to perform above average. Dispersion across individual markets will continue, but increased supply or economic headwinds in some markets will not derail the multifamily market's growth at the national level.

For more insights from the Freddie Mac Multifamily Research team, visit the Research page on FreddieMac.com/Multifamily.

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MULTIFAMILY

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Columbia Gas of Pennsylvania
House Line Reimbursement cost

Ln. No.	Category Description	Detail			Amount	
	(1)	(2) (#)	(3)	(4)	(5) ($)	
1	**Revenue**					
2	Customers (Additional)	275				
3	Bills	3,300	$ 16.75	$ 55,275		
4	Volume (DTH)	24,197	$ 4.7806	$ 115,677		
5				$ 170,952	$ 170,952	
6	**Rate Base**					
7	Mains (Additional)			$ 840,000		
8	Services (Additional)			$ 710,000		
9	Total Plant			$ 1,550,000		
10	Reserve for Depreciation			$ 18,524		
11	Net Plant			$ 1,531,476		
12	Deferred Income Taxes			$ -		1/
13	Rate Base			$ 1,531,476		
14						
15	**Carrying Cost**					
16	Rate base			$ 1,531,476		
17	Pre-tax rate of return			12.230%		2/
18	Carrying Costs including income taxes				$ 187,300	
19						
20	**O&M**					
21	Line Reimbursement			$ 275,000		
22	Standard O&M costs for new customers			29,007		
23	Total O&M				$ 304,007	
24						
25	**Depreciation**					
26	Mains	$ 840,000	2.01%	$ 16,884		
27	Services	$ 710,000	2.84%	$ 20,164		
28	Annualized depreciation				$ 37,048	
29						
30	Total Cost				$ 528,355	
31						
32	Net revenue (Cost) (Ln. 5 less Ln. 30)				$ (357,403)	3/

Notes

1/ Any incremental deferred income taxes will be offset by additional Net Operating Loss

2/ Pre-tax return:

	Ratio	Cost	Weighted	Gross-up of Income tax	Pre-tax
Total Debt	47.690%	5.033%	2.400%		2.400%
Equity	52.310%	11.000%	5.750%	58.510%	9.83%
Total	100.000%		8.150%		12.230%

3/ The net cost is futher impacted by uncollectibles at a rate of 1.277569% and late payments of 0.243400%.

Verbatim Customer Comments Regarding Payment Fees from Company Survey

<u>Pennsylvania</u>

"I don't like being charged $2.49. Why?"

"I will not pay a fee to use a valid credit card and I will not share my bank account information for payment therefore the online account is a waste of time."

"Charging a surcharge for electronic payment is a disgrace. This represents a clear cost savings to your company but you charge the customs MORE for using it."

"What a rip off charging to pay your bill like you do, I won't be using your site again."

"Don't charge to pay bill."

"Would like to be able to pay our gas bill via telephone with no fees. We can pay our electric and credit card bills via telephone. Why not our gas bill. Thank you."

"Extra 'convenience' charges (e.g. Bill Matrix) add up when customer is between jobs & on fixed income."

"I would like to see using my Debit Card on my account that I would NOT have to pay "ANY FEES"...AT ALL, since it is coming DIRECTLY from MY BANK ACCOUNT" and NOT any credit card company !! I am disabled and have to pay bills online so having to pay extra fees for my Debit Card is Totally Ridiculous!!"

"No fee payments."

"Any method of payment should be a free method."

"Sometimes I can't get a ride to pay bills so I pay online and having to pay $2.00+ just for a transaction fee from my bank is totally RIDICULOUS!!"

"Happy site does not charge a fee for transactions."

"Would like to see the option offered to pay gas bill on the phone without any fees or charges for doing so. Thank you."

"No fee for paying with credit card because I have excellent credit."

Columbia Gas of Pennsylvania Transaction Fee Costs	Actual Jan 2015 thru Dec 2015	Annual Projected Increase		
Category / Description	Number	Volumes	Cost Per Transaction	CPA Cost
TOTAL CPA Payments - All Channels	4,520,194	4,655,259		
TOTAL CREDIT & DEBIT CARD	164,163	316,424	$1.1250	$355,977
% of Total CPA Payments	3.63%	6.80%		
Total ACH Check Transactions	102,788	92,509	$0.60	$55,506
% of Total CPA Payments	2.27%	1.99%		
Total All Bill Matrix Payments	266,951	408,933		$411,483
% of Total CPA Payments	5.91%	8.78%		
Movement from Other Channels		141,982	-$0.07	($9,939)
Incremental O&M - CREDIT / DEBIT CARD and ACH				**$401,544**
TOTAL AUTHORIZED WALK-IN PAYSTATION	115,410	115,410	$1.00	$115,410
% of Total CPA Payments	2.55%	2.48%		
Incremental O&M - WALK-IN PAYSTATION				**$115,410**
Incremental O&M - CR/DB CARD and WALK-IN PAYSTATION				**$516,954**

COLUMBIA STATEMENT NO. 14

BEFORE THE
PENNSYLVANIA PUBLIC UTILITY COMMISSION

Pennsylvania Public Utility Commission	)	
	)	
vs.	)	Docket No. R-2016-2529660
	)	
Columbia Gas of Pennsylvania, Inc.	)	
	)	

DIRECT TESTIMONY OF
DEBORAH DAVIS
ON BEHALF OF
COLUMBIA GAS OF PENNSYLVANIA, INC.

March 18, 2016

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 Company's Hardship Fund.

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 for a community based agency assisting low income clients with accessing utility service and providing other basic life necessities. In 1992, Columbia hired me as a Community Relations representative and subsequently, I became Manager of the Customer Programs department. My titles changed, but I have remained in a similar function throughout my 24 year career at Columbia.

Q. Please describe the scope of your testimony in this proceeding.

A. I will address the Company's plan to seek additional funds for Columbia's Hardship Fund, as required by the Pennsylvania Public Utility Commission ("Commission") in the Company's last rate base proceeding, R-2015-2468056.

Q. Why is the Company planning to seek additional funding for its Hardship Fund?

A. In the Company's 2015 base rate proceeding, the Commission allowed temporary recovery of $375,000 through the Company's Rider USP to fund the Company's Hardship Fund. However, in its Opinion and Order dated December 3, 2015, the Commission stated that it intends "for Columbia to devise a plan by which it will transition toward funding its Hardship Fund entirely through voluntary means."

Q. What does the Commission's Order require regarding the funding of the Company's Hardship Fund?

A. Going forward, the Commission stated that the Company "shall have a plan in place to seek out the funding from voluntary sources and should address the alternative recovery of the hardship funding in its next base rate proceeding."

Q. Since the Commission's 2015 Order, has the Company considered funding its Hardship Fund through voluntary sources and other additional fundraising efforts?

A. Yes. The Company took several steps to consider additional fundraising opportunities, including:

1. The Company reviewed the 2013-2014 Hardship Fund Contributions chart published by the Commission to understand which utilities were highest in "voluntary ratepayer" contributions.
2. The Company reviewed current fundraising efforts as well as current outreach conducted by other Pennsylvania utilities to identify potential ideas for consideration.
3. The Company convened an internal work group composed of Columbia staff from the customer programs, regulatory, communications, government affairs and universal services departments, in order to consider new fundraising activities to increase donations. The work group explored existing and future opportunities to raise additional funds for Columbia's Hardship Fund.
4. The Company met with Dollar Energy Fund personnel to discuss the feasibility of conducting fundraising efforts to raise additional funds for the Hardship Fund.
5. The Company intends to include fundraising as an agenda item for future Universal Service Advisory council meetings. I note that the Universal Service Advisory council is being developed as a result of the final Order in Columbia's 2015 rate case.

Q. Did the Company come to any conclusions resulting from these efforts?

A. Yes. The Company concluded that its current efforts are in line with and similar to that of other gas utilities with regard to fundraising. Further, the Company determined that all of the additional fundraising efforts would result in greater administrative costs and, in some cases, increased advertising and promotional costs. Based on the 2013-2014 Commission report on Hardship Fund contributions and considering Columbia's customer contributions and fundraising efforts only ($150,000 total), the Company receives the 6th largest amount (out of 13) of voluntary ratepayer contributions and the 4th highest per customer amount, among the other Pennsylvania Natural Gas Distribution Companies ("NGDCs") and Electric Distribution Companies ("EDCs").

	Voluntary Ratepayer Contribution	Voluntary ratepayer contribution per Customer
Duquesne Light	$ 250,395	0.47
First Energy		
Met-Ed	$ 139,374	0.28
Penelec	$ 103,496	0.21
Penn Power	$ 38,671	0.27
West Penn	$ 167,258	0.27
National Fuel Gas	$ 43,769	0.22
PECO	$ 29,404	0.1
PGW	$ 612	0
PPL	$ 674,231	0.39
UGI	$ 82,934	0.25
People's Gas	$ 169,048	0.51
People's Eq	$ 85,286	0.35
Columbia Gas	$ 150,000	0.39

The Company's current outreach programs to encourage donations are consistent with other utilities. The Company will continue these outreach efforts and will discuss with its Universal Service Advisory council whether there are additional cost-effective outreach programs that could be attempted. Current fundraising efforts are also consistent with other utilities, including participating in the Dollar Energy Fund's Warmathon, Cool Down for Warmth campaign, and the annual golf outing. In addition, the Company sponsors the Trans-Siberian Orchestra concert in Pittsburgh each year. As part of this sponsorship, $0.50 for every ticket sold is donated to Columbia's Hardship Fund administered by Dollar Energy Fund.

The internal fundraising task force identified several opportunities or new fundraisers with the potential to increase voluntary ratepayer contributions. Although each of these new fundraising ideas has the ability to increase funds for the Hardship Fund, all require administrative resources. Some will need upfront seed money, as was the case in 1999 when Columbia conducted a fundraiser that featured the marketing of scale model vintage service trucks. Others will need additional funds for advertising and promotions such as the Trans-Siberian Orchestra sponsorship or new partnerships with community businesses or events. Dollar Energy Fund reported that their largest campaign raised less than $270,000 gross donations in one year, a significant portion of which was consumed by administrative expenses, including a dedicated staff person. Columbia will discuss these fundraising ideas with its new Universal Service Advisory council and seek potential sponsors.

Q. What specific fundraisers did Columbia's internal task force identify?

A. There were several fundraisers the task force identified including the following:

- Vendor/Contractor solicitation campaign
- Partnership with a minor league baseball team
- E-Bill sign up contest with funds being donated to the Hardship Fund
- Partnership with another entity to donate sales per product sold
- A new partnership with a venue for possible per ticket donation sponsorship
- Creation of a 5K event
- Ad messages on the back side of concert or sports ticket sales

Q. Has the Company considered any other opportunities to develop alternate funding sources for the Hardship Fund?

A. Yes, the Company has considered the use of pipeline penalty credits and/or refunds to help fund the Hardship Fund. The Company has proposed and the Commission has approved similar proposals in the past. Specifically, in 2009, the Commission authorized Columbia to apply disgorgement funds to its Hardship Fund that were received from Columbia Gas Transmission, LLC ("TCO") pursuant to a FERC-approved settlement.[1] In 2010, the Commission authorized Columbia to apply Federal Energy Regulatory Commission ("FERC")-approved Polychlorinated Biphenyl ("PCB") remediation over-collection refund proceeds from Tennessee Gas Pipeline ("TGP") to its Hardship Fund.[2] In 2012, the Commission authorized Columbia to use proceeds received from Columbia Gulf Transmission Company ("Gulf") through a settlement approved by FERC in a Gulf rate case at Docket RP11-1435.[3] On June 13, 2013, the Commission approved Columbia's Petition to use proceeds received from TGP through a FERC approved settlement at Docket RP11-1566.[4] On November 20, 2013, the Commission authorized Columbia apply to its Hardship Fund a portion of refund proceeds received from TCO through a FERC-approved settlement in Docket RP12-1021 regarding base rate levels and other issues related to the repair and maintenance of TCO's pipeline system.[5] In each of these instances, only the portion of the proceeds that might have otherwise been credited to residential customers through the Purchased Gas Costs ("PGC") were used for the Hardship Fund, and the remaining proceeds were credited to non-

[1] *Petition of Columbia Gas of Pennsylvania, Inc. Requesting Approval to Use Settlement Proceeds to Fund Residential Hardship Fund and Provide PGC to Small Commercial Customers*, Docket No. P-2009-2083915 (Order entered March 18, 2009).
[2] *Petition of Columbia Gas of Pennsylvania, Inc. for Expedited Approval to Contribute A Portion of Tennessee Gas Pipeline Settlement Proceeds to Fund Residential Hardship Fun and Provide PGC Credits to Small Commercial Customers*, Docket No. P-2010-2157040 (Order Entered April 19, 2010).
[3] *Petition of Columbia Gas of Pennsylvania, Inc. for Approval to Contribute Columbia Gulf Refund Proceeds to Residential Hardship Fund and Provide PGC Credits to Small Commercial Customers*, Docket No. P-2012-2292298 (Order Entered April 26, 2012).
[4] *Petition of Columbia Gas of Pennsylvania, Inc. for Approval to Contribute Tennessee Gas Pipeline Refund Proceeds to Residential Hardship Fund and Provide PGC Credits to Small Commercial and Industrial Customers*, Docket No. P-2012-2314912 (Order Entered June 13, 2013).
[5] *Petition of Columbia Gas of Pennsylvania, Inc. for Approval to Contribute Columbia Gas Transmission, LLC Refund Proceeds to Residential Hardship Fund and Provide Credits to Non-Residential PGC Customers*, Docket No. P-2013-2371147 (Order Entered November 20, 2013).

residential customers through the PGC. On February 3, 2015, Columbia filed a petition, seeking Commission approval to use TCO penalty credit proceeds from 2014 for the Hardship fund. That petition at Docket No. P-2015-2465533 is currently pending. On December 10, 2014, Columbia received $1,323,179.23 in TCO penalty credits, and the Company proposes to use $957,981.76 of those credits for the Hardship Fund, while crediting $365,197.47 to non-residential customers through the PGC.

Q. What is the Company proposing to help further fund its Hardship Fund as a result of the termination of the Rider USP funding?

A. The Company proposes the use of pipeline penalty credits and refunds as a funding source for the Hardship Fund, while it continues to develop plans to seek out funding from voluntary sources. The amount of pipeline penalty credits and refunds Columbia receives varies from year to year. The Company proposes to retain any funds over $375,000 received in a single year to fund future program years while it works to obtain other funding from voluntary sources. The Company would provide an annual report to interested parties detailing the amounts received, disbursed and retained for future years. For the $957,981.76 at issue in Columbia's pending petition, the Company's Hardship Fund would be adequately funded for almost 3 years while efforts to ramp up voluntary funding are explored and implemented.

Q. Would all pipeline penalty credits be considered for this purpose?

A. No. As in prior similar petitions, the Company proposes to use the residential portion of the supplier credits only. The Company will determine the residential/non- residential split based on the recently projected firm demand of those customers. Thereafter, the Company will refund the non-residential portion to small commercial and industrial customers as determined by the Company's Tariff, as it has done in previous petitions.

Q. Does the Company intend to continue to seek to identify means to increase voluntary contributions to the Hardship Fund?

A. Yes. As explained above, as part of the settlement of the Company's 2015 base rate case, the Company agreed to establish a Universal Service Advisory Council. Columbia will engage the participants of its Universal Service Advisory Council to solicit additional input on means to increase voluntary contributions to the Hardship Fund. The Council will be presented with ideas already developed, and will be consulted for further ideas.

Q. Does this conclude your direct testimony?

A. Yes, it does.